Australia's National Science Agency

Value of Distributed Energy Resources: Methodology Study

Final Report

October 2020

Citation

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Contents

Executive Summary

Households and businesses continue to install small-scale solar, energy storage technologies, and electric vehicles at an increasing rate. As adoption rates of these distributed energy resources (DER) increase (Figure 1) and customer expectations with respect to DER use evolve, distribution network service providers (DNSPs) have proposed to invest in projects aimed at increasing DER hosting capacity and to support a broadening range of DER services. DER can provide benefits to all users of the electricity system by lowering the overall costs of energy delivered.

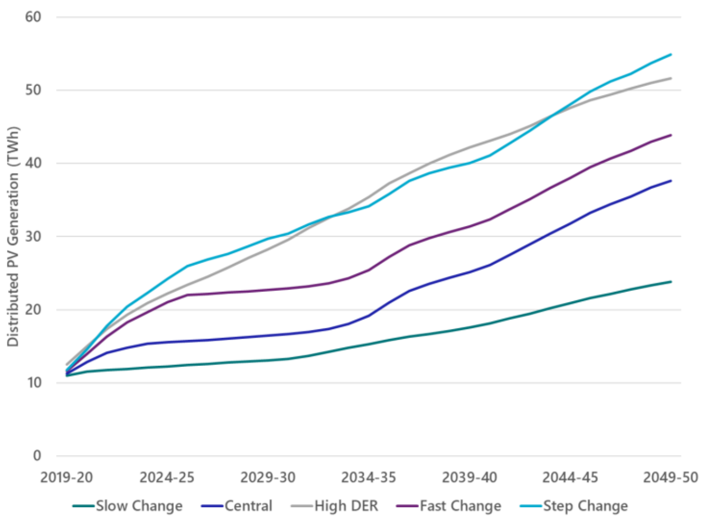

Figure 1 – AEMO DER scenario projections

This Value of DER (VaDER) Study, funded by the AER and ARENA and developed with the support of the DEIP Access and Pricing Steering Group, aims to deliver a simplified and transparent methodology for assessing the value of DER unlocked by proposed network expenditures to increase DER hosting capacity.

The key objectives of this Study are to:

- Engage with stakeholders to identify gaps and issues associated with current approaches and level of guidance on quantifying DER benefits
- Develop a methodology and approach for valuing DER benefits which reflect stakeholder feedback and are broadly accepted and supported by stakeholders as appropriate
- Provide a methodology for DNSPs to apply in valuing DER benefits which is practical, proportionate, repeatable, capable of flexibly accommodating jurisdictional differences, market reforms, differences in network visibility, access to data, and is likely to give rise to near optimal levels of investment
- Recommend the level of guidance that should be provided to DNSPs in quantifying DER benefits and guidance on how the methodology and/or methodologies should be applied.

Technical and regulatory processes for DER integration

The technical and regulatory processes networks may go through to integrate DER are complex, inter-related, and difficult to isolate. With that said, it may be helpful to provide an overview of these processes to better understand this Study's specific scope and how it relates to other initiatives underway.

In general, there is a generic four-step process that a network takes to propose a solution for a DER integration challenge and recovering costs associated with the solution. The four steps are:

1. Identify a problem (now or into the future) with integrating DER
2. Identify solution(s)
3. Assess the costs and benefits of identified/preferred solutions and the base case (e.g. the do-nothing 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

Separately, a network will determine how to recover these costs (and all other network costs) via its cost allocation method, tariff structure statement, and annual pricing proposals, all of which must be approved by the AER.

This Study provides a methodology that networks may use to determine part of step 3 – the benefits (i.e. the value of DER that is enabled through the network improving its integration of DER). Determining the costs – also part of step 3 – is outside the scope of this Study, as are the other steps. (The AEMC's consultation underway on requests for new rules to better integrate DER for consumers would primarily have implications for step 4 and the cost recovery process outlined).

In general, this Study is also agnostic about the actual DER technology. Rather, the focus is on the impact of a given network investment in relation to the additional capacity or energy services it provides to the electricity system. In other words, this Study is focused on developing a methodology that determines the benefits of an investment which increases DER hosting capacity.

Existing approaches to the valuation of DER

Some Australian distribution networks have prepared formal cost benefit assessments to support DER integration expenditure as part of the regulatory proposal process. However, this has resulted in several DNSP-specific approaches to the valuation of DER being adopted. Specific differences between these approaches have been noted in terms of:

- Types of value streams considered;
- Methodology for calculating value streams, in particular wholesale market value streams;
- Use of counterfactual (or base case) scenarios and sensitivity analysis; and
- Treatment of uncertainty.

The use of differing approaches has resulted in different values for DER benefits being applied, which creates challenges for consumer advocates and other stakeholders. The use of different approaches to the valuation of DER leads to challenges in assessing the relative merits of the proposed expenditure and in determining whether the value of DER adopted in the investment proposals is robust. It also imposes additional costs to DNSPs in preparing expenditure business cases and creates uncertainty in outcomes.

During our engagement activities, stakeholders expressed strong support for AER guidance aimed at assisting networks in calculating DER benefits in a more consistent, transparent and robust manner. DNSPs have also indicated that they are generally supportive of additional guidance from the AER, especially with respect to the calculation of wholesale market benefits as they do not necessarily have the expertise or experience in calculating these types of benefits.

Proposed Methodology

The methodology developed for determining the value of an increase in hosting capacity 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.

Mathematically, the methodology is expressed as:

$$\begin{aligned} Value\ of\ an\ increase\ in\ DER\ hosting\ capcity =\ & Investment\ costs_{(inc\ hosting\ capacity)} \\ & + Operating\ costs_{(inc\ hosting\ capacity)} + Enviro\ outcomes_{(inc\ hosting\ capacity)} \\ & -\ Investment\ costs_{(BAU)} - Operating\ costs_{(BAU)} - Enviro\ outcomes_{(BAU)} \end{aligned}$$

Our 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 the investment scenario.

DER value streams

An important aspect of the methodology is determining which costs and benefits associated with an increase in hosting capacity can be included. For most of the value streams identified, this task is simple. All agree that the benefits increased DER bring to the wholesale electricity market or to the provision of network services should be included. The treatment of certain costs and benefits – particularly those related to DER and environmental outcomes – is more contested.

The National Electricity Law (NEL) requires the AER to perform its functions in a manner that will contribute to the achievement of the National Electricity Objective (NEO). 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. The value streams that the AER may consider therefore must ultimately transfer benefits to electricity consumers in the long-term and must be shown to *increase consumer and producer surplus* – that is, the value streams must improve the welfare of both consumers and producers.

With regard to these principles, we have set out in Table 1 the relevant value streams that may arise as a result of a network investment to increase DER hosting capacity, and the extent to which they may be considered by the AER. Table 1 also summarises for what type of investment the value stream may be applied and the applicable method(s) for each DER service enabled.

Quantifying value streams

The regulatory investment test for distribution (RIT-D) and regulatory investment test for transmission (RIT-T) guidelines represent best practice in methods for quantifying value streams. We recommend that network businesses apply them where practicable.

We have proposed both a longhand and shorthand method for quantifying wholesale market benefits. RIT-T guidelines recommend market modelling, which we identify as the longhand method. The shorthand method is a simplified method which does not require electricity market modelling and is generally conservative. For network value streams, the existing approaches outlined in the RIT-D guidelines or in other AER guidance are largely fit for purpose where benefits can be identified.

Table 1 - Quantifying benefits from increasing hosting capacity for DER

<table>
<tr><th rowspan="2">Benefit Type</th><th rowspan="2">Value Stream</th><th rowspan="2">How DER integration delivers value stream</th><th rowspan="2">Able to be considered by AER</th><th colspan="3">Proposed Method</th></tr>
<tr><th>Network investment enables an increase in variable energy generation (passive DER)[1]</th><th>Network investment enables an increase in flexible energy generation (active DER)[2]</th><th>Network investment enables an increase in flexible generation capacity (active DER)[3]</th></tr>
<tr><td rowspan="3">Wholesale market</td><td>Avoided marginal generator SRMC</td><td>Increased DER generation substitutes generation by marginal centralised generators, which may have higher short-run marginal costs, in the form of fuel and maintenance costs</td><td>Yes</td><td rowspan="2">Applicable to all investments
Electricity market modelling or shorthand (total costs or running costs method)</td><td>Applicable to all investments
Electricity market modelling or shorthand (running costs method)</td><td>NA</td></tr>
<tr><td>Avoided generation capacity investment</td><td>Increased DER generation reduces the need for investment in new/replacement centralised generators</td><td>Yes</td><td>NA</td><td rowspan="2">Applicable to all investments
Electricity market modelling or shorthand (total costs method)</td></tr>
<tr><td>Essential System Services</td><td>Increased DER capacity enables more DER participation in ESS markets, reducing investment in new/replacement centralised ESS suppliers</td><td>Yes</td><td>NA</td><td>NA</td></tr>
<tr><td>Network</td><td>Avoided/deferred transmission augmentation</td><td>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</td><td>Yes</td><td colspan="2">Only applicable where generation aligns with peak
RIT-T or average LRMC approach</td><td>Applicable to all investments
RIT-T or average LRMC approach</td></tr>
</table>

[1] Variable energy – energy generated by passive DER systems with a profile dictated by technology type and resource conditions (e.g. solar PV, wind)

[2] Flexible energy – energy generated by active DER systems with a profile dictated by tariff structures and/or market conditions to maximise customer returns (e.g. batteries)

[3] Flexible capacity – active DER capacity available to provide services to wholesale markets (generally Essential System Services such as FCAS) or network services including demand management (e.g. batteries and demand response).

Benefit Type	Value Stream	How DER integration delivers value stream	Able to be considered by AER	Proposed Method Network investment enables an increase in variable energy generation (passive DER)[1]	Proposed Method Network investment enables an increase in flexible energy generation (active DER)[2]	Proposed Method Network investment enables an increase in flexible generation capacity (active DER)[3]
	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	Yes	Only applicable where generation aligns with peak RIT-D or average LRMC approach		Applicable to all investments RIT-D or average LRMC approach
	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	Yes	NA	Only applicable where additional batteries have been enabled. Approach based on batteries supplying customers during outages	
	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	Yes	Only applicable where generation aligns with peak RIT-D or average LRMC approach (if applicable)	NA	Applicable to all investments RIT-D or average LRMC approach
	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	Yes	Applicable to all investments but already included in wholesale market calculations		
	Avoided distribution losses	Increased DER generation can supply nearby loads, reducing the distance the energy travels across distribution network compared to centralised generators, which reduces the amount of energy lost to heat when transported over distribution lines	Yes	Applicable to all investments but already included in wholesale market calculations		

Benefit Type	Value Stream	How DER integration delivers value stream	Able to be considered by AER	Proposed Method		
				Network investment enables an increase in variable energy generation (passive DER)[1]	Network investment enables an increase in flexible energy generation (active DER)[2]	Network investment enables an increase in flexible generation capacity (active DER)[3]
Environment	***Avoided greenhouse gas emissions***	Increased DER generation substitutes generation by marginal centralised generators, some of which release greenhouse gases in the process of generating electricity	Yes, to the extent that there is a requirement for a market participant to pay a tax, levy or other payment associated with environmental or health costs or there is a jurisdictional requirement to consider the externality	Only applicable where there is a jurisdictional requirement to consider. Otherwise already included in wholesale market benefits Time-weighted emission intensity factor applied		
	Reduced health impacts of air pollution	Increased DER generation substitutes generation by marginal centralised generators, some of which release noxious gasses and particulates		Only applicable where there is a jurisdictional requirement to consider. Otherwise already included in wholesale market benefits Time-weighted emission intensity factor applied		
Customer	***Change in DER Investment Costs***	Change in DER investment or operational behaviour as a result of the network investment. (For example where an increase in hosting capacity incentivizes investment in larger sized solar systems than would have otherwise been the case). Will represent a negative benefit (or a cost) where a network investment encourages additional DER.	Yes, DER owners are considered to represent producers of electricity and therefore change in DER costs should be included.	Applicable to all investments which result in a change in customer investment in DER, which may represent a cost of additional DER (rather than a benefit). Calculated based on change in investment over total customer base		
	Electricity bill management	Increased DER generation and/or capacity provides DER customers with direct bill reductions via self consumption and/or via a feed-in tariff. Non- DER customers may experience a bill reduction or increase over time as a result of changes in wholesale and network prices where benefits are derived in these sectors (For example if network augmentation is avoided, prices go down)	No, as this would result in double counting of the benefits listed above in wholesale market and network segments, which ultimately transfer to customers as bill benefits.	Excluded		

Benefit Type	Value Stream	How DER integration delivers value stream	Able to be considered by AER	Proposed Method Network investment enables an increase in variable energy generation (passive DER)[1]	Network investment enables an increase in flexible energy generation (active DER)[2]	Network investment enables an increase in flexible generation capacity (active DER)[3]
	Willingness to pay for other perceived benefits (e.g. self-reliance, feel good factor, sense of contribution)	Increased DER generation may provide intangible benefits to customers beyond both financial and environmental benefits above.	No, we argue these benefits are external to the electricity system and therefore do not fit within the definition of electricity producer and consumer surplus (See Section 4.2.3). Regardless, capturing the consumer willingness to pay for DER which is truly *additional* to the value streams already captured is a complex exercise and not easily identifiable by either revealed preferences or willingness to pay surveys.		Excluded	

Results of Testing

The Methods described above were trialled for six worked examples including two worked examples relating to investments enabling additional rooftop solar PV generation. The rooftop solar PV examples can be compared to contemporary investment cases produced by Australian NSPs (which relate to similar, although not identical investment scenarios).

The outcomes in terms of the $/MWh value of additional rooftop solar from increased hosting capacity per additional unit of generation are shown in Figure 2 and compared to the values produced by Australian DNSPs to date in their investment cases to the AER.

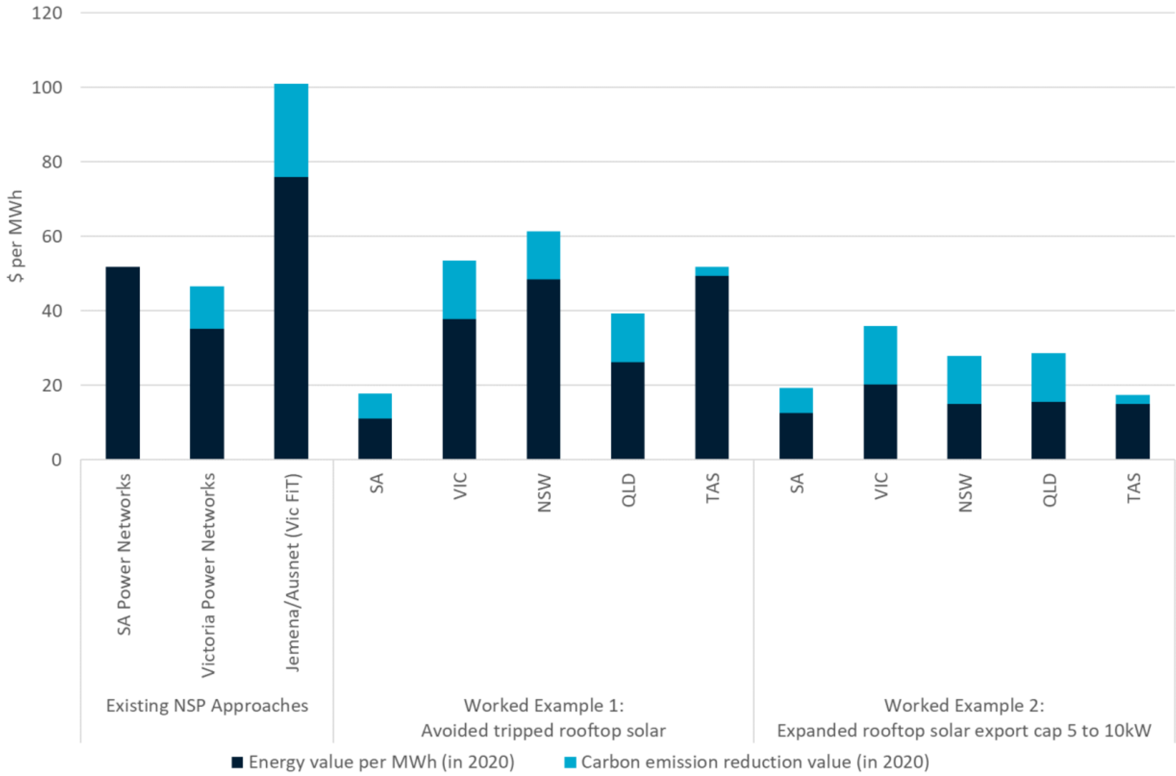

Figure 2 - Comparison of VaDER determined in this Study and existing NSP approaches

The difference in values determined in this Study result from three main factors:

1. Use of a profile which matches the *additional* DER exports enabled rather than an assumed standard solar generation profile. This profile will vary depending on the investment type.
2. The likelihood (in worked example 1) that the additional solar PV exports will only serve to displace large scale solar compared to the base case and therefore there are no short run marginal cost benefits, only long run marginal cost benefits (by avoiding investment in large scale solar).
3. The inclusion of the additional DER costs enabled by the network investment (in worked example 2). Worked example 2 assumes that the customers will install larger rooftop solar PV systems as a result of the network investment, whereas, worked example 1 assumes that the same DER investment occurs regardless of the network investment.

It should be noted that the values for the worked examples provided in Figure 2 include environmental outcomes. Environmental outcomes are only likely to be considered by the AER where there is a jurisdictional requirement for the network to do so.

Further, the values shown in Figure 2 are for 2020 only. The values for our worked examples (as presented in detail in this report) decrease over time. SA Power Networks and VPN also use values which vary over time according to the outcomes of electricity market modelling.

Recommendations for the AER

Publication of guidance note

The AER has already produced a number of guidance and practice notes to guide network businesses on how they might prepare business cases related to specific types of expenditure. It is recommended that the AER prepare a guidance note or practice guide setting out a principle-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 (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).

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.

Considerations for other bodies

Australian Energy Market Commission

AEMC could consider whether and how clarity may be provided as to how networks apply equity considerations to the allocation of hosting capacity, potentially via its current consultation on DER Access, Pricing and Incentive Arrangements Rule Change process aimed at updating regulatory arrangements for DER.[4] Consideration of equity implications may also require direction by State and Territory Governments.

There are currently a variety of existing approaches being taken to setting export limits via connection arrangements, whereby networks are attempting to manage power quality impacts and customer expectations with respect to DER exports. By virtue of this, whether explicitly or not, these approaches have equity implications between existing DER customers and future DER customers.

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[4] AEMC, Distributed energy resources integration - updating regulatory arrangements, Consultation paper, 30 July 2020

While this issue is broader than our Study, it has implications for the way in which network businesses consider the base case in their DER integration business cases.

State and Territory Governments

Where no other formal policy mechanism to value carbon emission reductions exists, State and Territory governments could consider requiring network businesses, who operate in their jurisdictions, to value the potential carbon emission reduction benefit of an increase in DER hosting capacity in their cost benefit assessments for DER integration and nominate the value to be adopted (in terms of $ per tonne of carbon equivalent avoided).

Where a State or Territory government elects to do this, the methodology set out in this report provides a mechanism for networks to calculate value of avoided carbon emissions.

Glossary

Abbreviation	Meaning
ACCU	Australian Carbon Credit Units
ACOSS	Australian Council of Social Services
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
API	Application Programming Interface
Capex	Capital Expenditure
CBA	Cost Benefit Analysis
CCP	Consumer Challenge Panel
DEIP	Distributed Energy Resources Integration Program
DER	Distributed Energy Resource
DNSP	Distribution Network Service Provider
EFA	Expenditure Forecast Assessment
ENA	Energy Networks Australia
EPRI	Electric Power Research Institute
ESB	Energy Security Board
ESC	Essential Service Commission
ESS	Essential System Services
EV	Electric Vehicles
FCAS	Frequency Control Ancillary Services
FIT	Feed-in Tariff
GW	Gigawatts
GW/h	Gigawatt Hours
ISP	Integrated System Plan
kWh	Kilowatt hour
kW	Kilowatt

LRMC	Long-Run Marginal Cost
LV	Low Voltage
MLF	Marginal Loss Factors
MW	Megawatt
NEL	National Electricity Law
NEM	National Electricity Market
NEO	National Electricity Objective
NER	National Electricity Rules
NSP	Network Service Provider
NT	Northern Territory
NY	New York
OEN	Open Energy Networks
Opex	Operating Expenditure
PV	Photovoltaic
Repex	Replacement Expenditure
RET	Renewable Energy Target
RIT-D	Regulatory Investment Test - Distribution
RIT-T	Regulatory Investment Test - Transmission
SAPN	SA Power Networks
TOU	Time of Use
TNSP	Transmission Network Service Provider
SAPN	South Australian Power Networks
SRMC	Short Run Marginal Cost
UE	United Energy
VaDER	Value of Distributed Energy Resources
VCR	Value of Customer Reliability
V2G	Vehicle to Grid
VPP	Virtual Power Plant

1 Introduction

Households and businesses continue to install small-scale solar and energy storage technologies at an increasing rate. Notwithstanding potential short-term impacts from COVID-19, this trend is likely to remain strong for the foreseeable future against the backdrop of falling prices for PV, batteries and electric vehicles (EVs); growing consumer sentiment towards the need for climate action; the growing desire for customers to have greater control of energy usage; and the introduction of government initiatives aimed at achieving renewable energy and carbon targets.

The Australian Energy Market Operator (AEMO)[5] anticipates rooftop solar capacity to double or even triple by 2040 (Figure 3). From a lower base, customer battery capacity is expected to increase between 4 to 20 times in the same period.

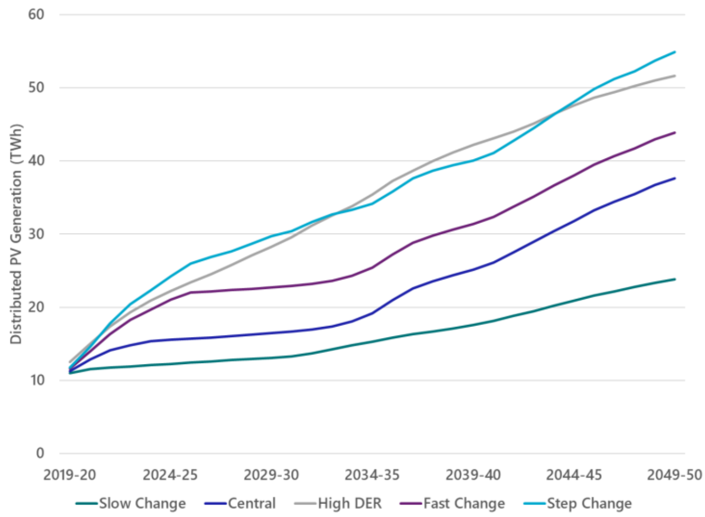

Figure 3 – AEMO DER scenario projections

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 DER hosting capacity and supporting a broadening range of DER services. Many distribution network service providers (DNSPs) have already prepared or are currently considering preparing business cases to justify such projects on an economic basis. This justification requires the quantification of 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 (producers and consumers).

The optimal outcome is the ongoing development of electricity networks that most efficiently balance the costs of the grid with the benefits that DER can provide. Such an outcome would both avoid overbuilding the networks and excessive costs to consumers and avoid underbuilding where DER is inefficiently restrained from access to the markets.

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 the Australian Energy Regulator (AER) 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 which have DER.

[5] AEMO, 2020 Integrated System Plan, July 2020.

To address these issues, the AER is developing a guideline to assessing DER integration expenditure which seeks to provide DNSPs with additional guidance on how to treat this relatively new investment driver. The DER Integration Expenditure Assessment Guideline will provide guidance to DNSPs on the types of analysis they might conduct to determine if expenditure relating to increasing DER penetration is prudent and efficient.

1.1 Purpose

This study, funded by the AER and ARENA and developed with the support of the DEIP Access and Pricing Steering Group,aims to:

- Investigate methodologies for evaluating the benefits of enabling additional DER energy generation or capacity beyond the current ability of the network; and
- Recommend an approach which is fit for purpose and promotes transparency, consistency, and predictability of expenditure outcomes under the regulatory process.

To achieve this purpose, we have sought to:

- Engage with stakeholders to identify gaps and issues associated with current approaches and level of guidance on quantifying DER benefits;
- Develop an approach for valuing DER benefits which reflects stakeholder feedback and is broadly accepted and supported by stakeholders as appropriate;
- Provide a detailed methodology for DNSPs to apply in valuing DER benefits which is practical, proportionate, repeatable, and capable of flexibly accommodating jurisdictional differences, market reforms, and differences in network visibility and access to data; and
- Recommend the level of guidance that should be provided to DNSPs in quantifying DER benefits and guidance on how the methodology and/or methodologies should be applied.

It is envisaged that the approach proposed by this Study will assist in informing the AER’s approach to assessing DER expenditure in future DNSP regulatory proposals and assist DNSPs in justifying DER-related expenditure.

1.2 Approach

The study was conducted over five distinct steps, as illustrated in Figure 4.

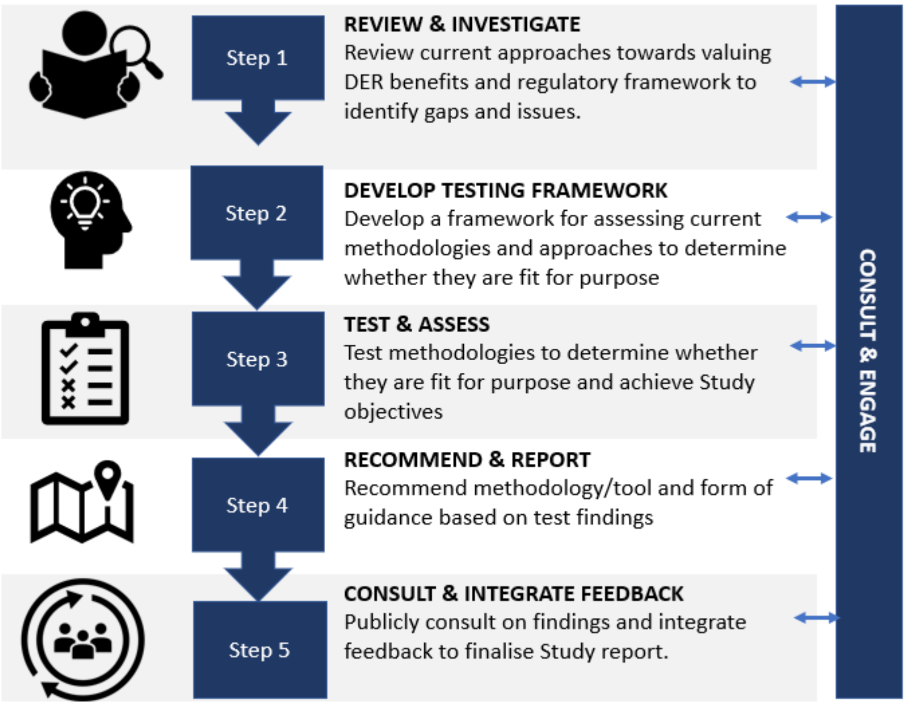

Figure 4 - Study steps

Throughout the preparation of the Study, we have engaged with a broad range of stakeholders (including consumer groups, industry, service providers, government, and market bodies) to gain a diverse range of views and perspectives to shape our findings and recommendations. The stakeholder organisations we engaged with are listed in Appendix A.1 while a summary of themes that emerged from our stakeholder engagement activities is provided in Appendix A.2.

In addition to targeted engagement with stakeholders, the report was subject to public consultation with the feedback from this broader engagement process incorporated into this final report. The response to submissions are contained in Appendix B.

1.3 Scope

There are a broad range of issues facing the NEM regarding DER integration and uptake, and a plethora of different reforms and initiatives aimed at addressing these issues. Consequently, it is important to clarify:

- the types of DER examined as part of this Study;
- the investment types that the methodology is intended to apply to; and
- the specific issues to be addressed by the Study.

Each of the above matters is discussed in further detail below, with further context provided in section 2.

1.3.1 Types of Network Investment

This Study seeks to develop a methodology for quantifying benefits associated with a network investment which:

1) Enables additional DER energy generation or capacity beyond the current ability of the network to accommodate (i.e. increases hosting capacity)
2) Has benefits which accrue to more than one customer which are recovered from the broader customer base.

DER services enabled by network investment

Throughout this report we refer to three types of services which may be enabled by investment in DER integration:

Variable energy – energy generated by passive DER systems with a profile dictated by technology type and resource conditions (e.g. solar PV, wind)

Flexible energy – energy generated by active DER systems with a profile dictated by tariff structures and/or market conditions to maximise customer returns (e.g. batteries)

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

Active DER can provide both flexible energy and capacity, while passive DER will only provide variable energy.

For the purpose of this Study, investment may be in relation to capital expenditure in the network and/or operational expenditure to procure non-network options; however, if the investment does not meet the above criteria it is considered outside the scope of this Study.

The Study is generally agnostic to the actual DER technology and is instead focused on the impact of a given network investment. In other words, the Study is focused on a methodology that more clearly articulates effects of network investment in relation to increasing, decreasing or changing the way DER systems produce electricity or manage demand to benefit electricity consumers.

1.3.2 Focus of this Study

As noted in section 1.1, the purpose of this Study is to investigate and develop a methodology for quantifying the benefits associated with DER-driven expenditure by DNSPs. The Study does not seek to provide broader guidance on how to undertake cost benefit assessments, nor how to calculate or define increased hosting capacity[6]. The Study is specifically focussed on how to value a change in DER generation and/or capacity enabled by a network investment.

[6] Note that some stakeholders did suggest that further guidance as to how networks should calculate hosting capacity and in particular how the volume of otherwise “spilled” solar generation should be calculated.

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. The four steps are:

1. Identify a problem (now or into the future) with integrating DER
2. Identify solution(s)
3. Assess the costs and benefits of identified/preferred solutions and the base case (e.g. the do nothing 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

Separately, a network will determine how to recover these costs (and all other network costs) via its cost allocation method and tariff structure statement and annual pricing proposals, all of which must be approved by the AER.

This consultation focuses on determining a methodology that networks might use to determine part of step 3 – the benefits (i.e. the value of DER that is enabled through the network improving its integration of DER). Determining the costs – also part of step 3 – is outside the scope of this consultation as are the other steps. (The AEMC's consultation underway on requests for new rules to better integrate DER for consumers would primarily have implications for step 4 and the cost recovery process outlined).

In general, the Study is also agnostic about the actual DER technology. Rather, the focus is on the impact of a given network investment in relation to the additional capacity or energy services it provides to the electricity system. In other words, the Study is focused on developing a methodology that determines the benefits of an investment which increases DER hosting capacity.

1.4 Report Structure

Our Final Report is structured around the following themes:

- ***Section 2: Context*** – Provides the context on the drivers for this Study and how this Study fits within and contributes to the existing reform landscape.
- ***Section 3: Types of Existing AER Guidance –*** Examines the various forms of guidance provided by the AER to networks
- ***Section 4: DER Value Streams –*** Provides an overview of key DER value streams, what value streams can be considered by the AER and how value streams translate to customer benefits.
- ***Section 5: VaDER Methods*** – Sets out our proposed methods for valuing additional DER generation as a result of network investment.
- ***Section 6***: ***Conclusions and Recommendations*** –Sets out the overall conclusion and recommendations for consideration by the AER and other bodies.
- ***Appendix A: Initial stakeholder engagement*** - Outlines stakeholder engagement undertaken at project outset including list of organisations consulted and key stakeholder themes
- ***Appendix B: Response to stakeholder submissions*** – Provides responses to stakeholder submissions received on draft consultation report by key themes

- ***Appendix C*: *Overview of DER Integration Related Reforms*** – Summaries relevant reforms underway related to DER integration
- ***Appendix D: Existing Approaches to Valuing DER***: – Provides a review of exiting approaches to valuing DER both in Australian and internationally
- ***Appendix E: Method Selection***: - Sets out our proposed approach for selection of methods for valuing DER benefits derived from a network investment
- ***Appendix F Method formulas and worked examples*** *– Provides detailed formulae and worked examples for each proposed method*

2 Context

This section provides further context on the drivers for DER expenditure, the barriers to increasing network hosting capacity, current issues identified with valuing DER approaches, and how this Study fits within the broader DER reform landscape. The section aims to highlight the broad array of interrelating and overlapping issues associated with facilitating efficient DER integration and to highlight the specific issues that this Study will seek to address.

What is DER?

For the purposes of this study, we have adopted the same definition used by the AER in its *Assessing DER Integration Expenditure* consultation paper, which defines DER as:

flexible resources connected to low voltage networks which produce electricity or manage demand

2.1 Current issues with valuing DER

Through our engagement activities with stakeholders several issues were raised in relation to current approaches used towards valuing DER. These include:

- ***Lack of consistency/transparency in approach used*** – DNSPs have adopted different approaches for justifying DER expenditure which can make it difficult for the AER to compare and benchmark expenditure against other DNSPs. For example, SA Power Networks (SAPN) used avoided dispatch costs,[7] CitiPower/Powercor/United Energy (UE) used avoided generator short run marginal costs (SRMC),[8] while Jemena[9] and AusNet[10] have sought to apply the Essential Service Commission (ESC) Victorian feed-in tariff (FiT) as a proxy for valuing DER benefits. The different approaches applied by DNSPs has resulted in varying degrees of transparency surrounding the process undertaken and the inputs and assumptions used, making it difficult for stakeholders to interrogate the veracity of modelling used to quantify DER benefits.
- ***Consideration of the base case***: DNSPs have adopted different approaches to the definition of a base case with most defining the base case as an option which requires them to apply static export limits (at a low or zero level) rather than allow tripping to occur.
- ***Visibility and access to data*** – DNSPs have varying degrees of LV visibility and data about their systems. This affects the level of granularity and accuracy of methods adopted for valuing DER benefits and is also a key driver for DNSPs adopting a conservative approach towards setting DER export limits within the connection agreement. Networks with low visibility of their networks have a limited understanding of the baseline amount of DER their networks can

[7] SAPN, Supporting Document 5.20 - Houston Kemp: Estimating avoided dispatch costs and VPP - Jan 2019 – Public.

[8] Jacobs, 'Market Benefits for Solar Enablement: Victoria Power Networks and United Energy – Final Report,' Rev 1, 15 August 2019.

[9] Jemena Electricity Networks Vic Ltd, 2021-26 Electricity Distribution Price Review Regulatory Proposal, Attachment 05-04: Future Grid Investment Proposal (Public), 31 January 2020.

[10] Frontier Economics, 'Value of relieving constraints on solar exports: A report for AusNet Services,' 16 October 2019.

handle. While increasing visibility is likely to support increased hosting capacity, any method for valuing DER recommended as part of this Study will need to flexibly account for differences in DNSP visibility and access to data.

- ***Accounting for uncertainty*** – DNSPs have adopted varying approaches for accounting for uncertainty. For the most part, DNSPs have not applied best practice approaches (such as those outlined in the RIT-D) surrounding the use of sensitivity testing, and consideration of option value and staging that seek to account for investment uncertainty and risk.
- ***Difficulties in standardising network benefits*** – network benefits are very spatial and temporal in nature making them difficult to standardise.
- ***Concern that current approaches may over-state benefits –*** stakeholders have raised concerns that use of FiT for calculating wholesale benefits may overstate benefits and may not be appropriate in the current context. Further, some stakeholder groups expressed concern that current approaches failed to appropriately consider DER self-consumption and appeared to assume that solar PV's will be exporting at maximum capacity every day.
- ***Which benefits should be included in the value stack –*** there is a lack of clarity regarding which benefits can be considered in developing business case expenditure, particularly around the appropriateness of including environmental benefits such as avoided greenhouse gas emissions/avoided cost of carbon. While all the Victorian DNSPs included environmental benefits as part of their quantification of DER economic benefits,[11] SAPN adopted a more conservative approach and did not include environmental benefits as part of its DER value stack. It is worth noting that most stakeholders (both consumer groups and networks) have expressed support for environmental benefits to be included.
- ***Aggregation of stacked benefits –*** some DER, particularly energy storage, have the potential to provide multiple benefits to the system. Appropriately accounting for all value streams when stacked can be challenging, given the potential for changes in operational practices to realise certain benefits. For example, a battery may need to reserve a certain portion of its capacity to provide distribution system capacity, which would mean that capacity cannot be used when accounting for the value of another benefit, for example, wholesale energy.
- ***Approach to valuing customer preferences*** – customer support for DNSP expenditure to increase DER hosting capacity was a theme that featured strongly in Victorian DNSP proposals. However, while the Consumer Challenge Panel (CPP) was supportive of the consumer engagement activities undertaken by the Victorian DNSPs, it expressed concerns on how discussions were framed. The CPP considered that the discussion should have been framed around what incremental value consumers placed on additional exports. [12]
- ***Future market developments –*** DER can provide a variety of services, including generation capacity and essential system services which, aside from frequency control, at present do not have active markets in the NEM. Where markets do exist, the specific rules governing DER

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[11] Jemena and AusNet used the ESC Victorian FiT to quantify environmental benefits, while CitiPower/Powercor/United Energy used Australian Carbon Credit Units as the basis for calculating environmental benefits.

[12] Consumer Challenge Panel – Sub-Panel 17, 'Advice to the AER on the Victorian Electricity Distributors' Regulatory Proposals for the Regulatory Determination 2021-26,' 10 June 2020.

participation in the markets may not be adopted or are in nascent pilot stages. As a result, determining the future benefits of DER within these markets is often challenging, if not impossible. Section 2.5 outlines current initiatives aimed at facilitating the efficient integration of DER and optimising customer benefits.

Variability of DER network benefits

Network benefits from DER are affected by the following:

- ***Location*** – value can vary based on the DER location within the network, specifically in terms of its proximity to areas of the network that are congested, or nearing congestion
- ***Time*** – value can vary according to the extent electricity generation coincides with periods of peak demand within the section of the network where the generator is connected
- ***Asset life-cycle*** – the value can vary based on the timing of network augmentation and replacement
- ***Capacity*** – the generation capacity of the distributed generation
- ***The ability to optimise DER*** – this is largely a function of DER being both predictable and responsive to the needs of the network
- ***Use of technology to transform intermittent generation into firm generation*** – technologies, such as energy storage (batteries) and energy management technologies, can enable DER orchestration and increase their potential value.

Source: Essential Service Commission, 'The Network Value of Distribution Generation: Distribution Generation Inquiry – Stage 2,' February 2017

Further details on stakeholders consulted, key themes and issues identified as part of our preliminary stakeholder engagement are outlined in Appendix A.

2.2 Suitability of the RIT-D guidelines to DER integration investments

As noted by DNSPs in their expenditure proposals and in their response to the AER's consultation paper on Assessing DER Integration Expenditure, the market benefit assessment framework in the RIT-D generally provides a suitable framework for determining the efficient level of DER expenditure. As noted by Victorian DNSPs in their business cases for DER expenditure, the RIT-D already contemplates:

> *"changes in fuel consumption arising through different patterns of generation dispatch, changes in ancillary service costs, and competition benefits"*

as additional market benefits under paragraph 7.h. of the RIT–D Guideline. [13]

However, it has become apparent from our discussions with stakeholders that while the RIT-T provides some guidance on the methodology, further guidance on which inputs and values to use, particularly with respect to benefits in the wholesale generation market, is required in the RIT-D application guidelines to provide greater clarity and certainty to DNSPs.

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[13] Refer to section 3.6.2, AER, 'Application Guidelines: regulatory investment test for distribution,' December 2018.

Our engagement activities with stakeholders indicated perceived gaps with the RIT-D guidelines in terms of providing sufficient guidance on which benefits could be considered in calculating the DER value stack. DNSPs also noted that the RIT-D is intended to be applied on a project-specific basis, whereas expenditure proposals tend to be prepared on a program basis where location-specific benefits are difficult to determine. Additionally, concern was expressed that the approach for quantifying benefits as set out in the RIT-D guidelines may be too complex and administratively burdensome to apply to smaller DER integration projects/programs. Some stakeholders considered that it may be more appropriate for the AER to develop several cost-benefit assessment approaches that could be flexibly applied by DNSPs depending on the nature and cost of the investment.

2.3 Defining the base case

Under the current regulatory framework, it is unclear how a prudent and efficient network should balance high levels of DER penetration and network investment. Under high levels of solar PV penetration, there is the potential for voltage to regularly exceed network limits. Under such circumstances, inverter systems will generally “trip” such that they cannot generate until network voltage has returned to within network limits. Some networks are considering or have implemented low or zero export limits to ensure that network voltage limits are maintained and to limit the degree to which DER customers are impacted by tripping. Stakeholders have raised concerns that there are considerable equity issues with this approach and that the “first come, first serve approach” may not be appropriate. However, networks are reluctant to rely on the inverters in managing voltage issues, due to both issues with inverter standard compliance as well as the potential for high volumes of customer complaints.

This is an issue for the day-to-day management of the network in terms of processing connection applications, but in the context of this Study, presents challenges to defining a base case for the purpose of cost benefit assessment of DER integration investments.

The RIT-D guidelines set out that where no mandatory service standard or regulatory instrument is driving the investment, 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 project nor implement any other credible option to meet the identified need*”. While the base case option may eventually result in unrealistic outcomes, 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.

While the RIT-D guidelines do not provide any specific guidance for DER integration investments, it is clear from the above that the base option should represent no new network intervention. As 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, the base case could allow inverter systems to “trip” at times where DER exports exceed hosting capacity.

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. 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).

Similarly, if networks have not already implemented a time-of-use (TOU) network tariff to encourage consumption when solar production – and voltage exceedance – is highest, the low-cost approach of implementing a TOU tariff to reduce network impacts is not included in the base case. TOU network tariffs are likely to be a credible, low-cost option to increase DER capacity; transparent discussion of the use of TOU network tariffs treatment can help elucidate the base case, investment case, and network approaches to calculating hosting capacity.

Perhaps the largest issue with relation to identifying the base case is accurately identifying the amount of DER a network could host absent any investment. There is no common approach used by networks to determine how much DER their distribution system could host in the base case or in the investment case. Even if such an approach were articulated, many networks would struggle to accurately implement it because they lack data and visibility on the condition of their low-voltage network.

To date, most networks[14] 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. 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.

2.4 How does this report fit within the landscape of DER-related policy and market reforms?

There are a plethora of different policy and market reforms aimed at addressing issues associated with increasing DER penetration and integration issues. A summary of different reforms and projects aimed at examining DER integration and network hosting capacity is provided in Appendix C.

The technical and regulatory processes networks may go through to integrate DER are complex, inter-related, and difficult to isolate. With that said, it may be helpful to provide an overview of these processes to better understand this Study's specific scope and how it relates to other initiatives underway.

In general, there is a generic four-step process that a network takes to propose a solution for a DER integration challenge and recovering costs associated with the solution. The four steps are:

1. Identify a problem (now or into the future) with integrating DER
2. Identify solution(s)
3. Assess the costs and benefits of identified/preferred solutions and the base case (e.g. the do-nothing 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

[14] SA Power Networks and Jemena assume static exports in base case, while CitiPower, Powercor and UE assume tripping

Separately, a network will determine how to recover these costs (and all other network costs) via its cost allocation method, tariff structure statement, and annual pricing proposals, all of which must be approved by the AER.

This consultation focuses on determining a methodology that networks might use to determine part of step 3 – the benefits (i.e. the value of DER that is enabled through the network improving its integration of DER). Determining the costs – also part of step 3 – is outside the scope of this consultation as are the other steps.

Three separate rule change requests recently submitted to the AEMC by SA Power Networks, the St Vincent de Paul Society Victoria, and the Total Environment Centre together with the Australian Council of Social Service seek to clarify the obligations distribution networks have to ensure customers' DER can connect and export to the grid. These rule requests relate to step 4 and the cost recovery process. Some of these proposals seek to create an obligation on networks to enable DER to connect and export to the grid just as networks today have an obligation to connect any/all customer consumption.

Obliging networks to enable DER to connect and export to the grid could have impacts on the allocation and recovery of costs for solutions to integrate DER. For example, if networks have an obligation to enable DER exports – even if the costs of enabling such exports were seen to be greater than the benefits – then cost recovery would likely be granted by the regulator if the costs were seen to be prudent and necessary to enable DER exports.

There is also a key issue related to cost allocation and pricing, which some of these rule change requests also address. They argue that costs to integrate DER should be allocated to those customers who want to export energy from their premise and are largely causing additional costs to be borne by the network. In cases in which the value of DER exceeds the cost of new integration programs, it may be appropriate to apply the costs of network integration to all customers, as all customers would benefit from the additional DER. On the other hand, if DER customers are causing the need for new network expenditure and are also receiving a disproportionate share of the benefits from that expenditure, then it may be appropriate to allocate costs more directly to those customers. In cases in which DER integration costs exceed the benefits of the integration expenditure – and the rules mandate customer access to the grid for export – then it may be appropriate to allocate the net costs through export tariffs or other means specifically to DER customers.

The need for this study was first conceived as part of the Distributed Energy Integration Program (DEIP) Dive workshop in May 2019 and formed an action under the DEIP Access and Pricing workstream. The Study then directly arose from action items 2 and 3 under the AEMC's Electricity Network Economic Framework Review 2019. Action item 2 is aimed at developing a common value of customer export methodology which could be used for the purpose of determining the value of marginal increases in hosting capacity.[15] This action item is intended to feed into Action item 3, which directs the AER to provide guidance on efficient DER expenditure.

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

As noted in section 1, this Study is aimed at informing the development of the AER's DER Integration Expenditure Assessment Guideline that is currently in the process of being developed. This Study is not intended to address all aspects intended to be covered by the AER's guideline but rather is intended to inform the consideration of the market benefit component of the cost benefit analysis process.

While reforms to pricing, incentives, connection arrangements, and technical standards form an important part of facilitating efficient integration of DER and optimisation of customer benefits, these issues are generally out of scope of this Study. The following reforms, while out of scope of this Study, are related and worth noting:

- ***DEIP Access and Pricing Working Group –*** aimed at examining how the economic regulatory framework should evolve to meet changing user expectations in light of higher DER penetration and to build consensus on equitable and efficient DER access and pricing models. This work is intended to result in several rule change requests to reform the network charging arrangement to better reflect the changing interaction between consumers and the electricity system and potentially trigger more hosting capacity expenditure proposals by DNSPs.
- ***ENA and AEMO's Open Energy Networks Program –*** aimed at developing a distribution operating model for integrating DER and identifying required network capabilities to support DNSPs' transition to being an enabling platform. This is relevant as it may trigger more investment in projects likely to be captured by the AER's impending DER Integration Assessment Expenditure Guideline.
- ***Energy Security Board Post 2025*** – the Energy Security Board (ESB) is exploring the design of what a two-sided market (where all types of energy users actively buy and sell electricity) could look like, which is relevant to this Study as it will change market supply and price quantities, as well as participation options for DER. The ESB is also looking at new markets for operating reserves and essential system services and how these services should be valued. This has the potential to impact DER values as essential system services form part of the DER value stack.
- ***Rule change requests to integrate more DER –*** AEMC has started a process to examine proposed changes to the power system's regulatory framework. The changes were proposed by Total Environment Centre and the Australian Council of Social Services (ACOSS), SA Power Networks, and St Vincent de Paul Society with an aim to integrate more DER in a way that benefits all electricity consumers. The proposed changes are targeted at improving the framework for network planning and investment as well as the access and pricing arrangements for DER.

3 Types of Existing AER Guidance

As part of this Study we have sought to identify the extent of existing guidance provided by the AER to DNSPs in undertaking cost benefit assessments more broadly to identify current gaps. We have also reviewed the types of guidance provided by AER to DNSPs in other contexts.

3.1 Guidance in undertaking cost benefit assessments

The AER expects DNSPs to submit cost benefit assessments in support of forecasted projects and expenditures in general[16]. The AER provides comprehensive guidance to DNSPs as to how to undertake cost benefit assessments for the purposes of the Regulatory Investment Test-Distribution in its RIT-D application guidelines,[17] which are applied by networks to justify investment greater than $6 million.

RIT-D guidance, however, is not required and was not intended to be applied to the justification of investments within the regulatory reset process. Investments set out in the regulatory proposals are often programmatic in nature (rather than discrete projects) and so it can be difficult to strictly apply the RIT-D process at this time. Notwithstanding, the RIT-D guideline provides useful guidance to DNSPs as to how to undertake robust cost benefit assessments in any context including:

- The types of benefits which may be considered
- Methods for evaluating benefits
- Assignment of probabilities to scenarios
- Use of options / staged / contingent projects
- Use of counterfactuals, sensitivities and scenarios
- Choice of modelling period
- Use of the AEMO ISP as the primary source of assumptions.

The RIT-D guidelines provide worked examples of how to calculate various benefits. The RIT-D guidelines however do not set out how DNSPs should assess wholesale market or inter-regional impacts and instead provide high-level guidance and refers to the RIT-T application guidelines. The RIT-T application guidelines provide additional guidance on how wholesale market benefits should be modelled including that:

“Market dispatch outcomes can be modelled using market or pool dispatch models that simulate or forecast wholesale spot market outcomes in the presence of each credible option, as well as in the base case. Such models should operate using bid-based merit order dispatch so they produce similar results to the dispatch algorithm AEMO uses to dispatch and settle the NEM”.

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16 Better Regulation: Expenditure Forecast Assessment Guideline for Electricity Distribution, November 2013

17 AER, Final Decision – Application guidelines for the regulatory investment tests, December 2018.

3.2 Other types of AER guidance

The AER provides a range of guidance to DNSPs generally to provide clarity as to how the AER intends to assess a certain category of expenditure (where the assessment approach was previously unclear).

The guidance can take a range of forms including:

- principle based guidance
- methodology statements
- input values it expects DNSPs to adopt
- calculation tools the AER uses in its assessment of expenditure, which may also be used by DNSPs in proposing expenditure.

A summary of guidance currently provided by the AER is provided in Table 3 below.

Table 3 – Types of AER guidance

Guidance	Guidance description	Type of guidance	Rationale for guidance
Values of customer reliability[18]	Provides values of customer reliability (VCR) for unplanned electricity outages of up to 12 hours in duration. VCRs seek to reflect different types of value customers place on having reliable electricity supply under different conditions and are usually expressed in dollars per kilowatt hour ($/kWh). They form an important input in identifying efficient levels of network expenditure and in determining reliability standards.	Values and methodology statement	The AEMC determined, as part of its assessment of 'Establishing values of customer reliability' rule change, that assigning a single body responsibility for developing a nationally consistent VCR methodology and for calculating VCR estimates would remove unnecessary duplication and decrease the overall administrative burden associated with the use of VCR by a wide range of stakeholders.[19] The AER was considered the most appropriate body for developing the VCR methodology and VCR estimates on an on-going basis because the responsibility is more closely aligned with its statutory functions, and, as the economic regulator, the AER is well equipped to assess trade-offs between cost and reliability.

[18] AER, Values of Customer Reliability, Final Report on VCR values, December 2019.

[19] AEMC, Establishing VCRs, Rule determination, 5 July 2018.

Guidance	Guidance description	Type of guidance	Rationale for guidance
Expenditure Forecast Assessment Guideline[20]	The guideline specifies: 1) the approach the AER uses to assess capital expenditure (capex) and operating expenditure (opex) forecasts 2) the information the AER requires from network service providers (NSPs) to make its assessment.	Principles	Clarifies the approach the AER will take in assessing NSP expenditure proposals and the use of benchmarking.
Replacement model handbook[21]	Handbook sets out how the AER's replacement expenditure (repex) model is to be used assessing NSP regulatory proposals. It provides a series of Microsoft Excel spreadsheets that enables benchmarking of replacement capital expenditure.	Calculation tool/ Handbook	The handbook is intended to provide background and context for the repex model and explain the model so that NSPs could familiarise themselves with the repex model and its application.
Application Guidelines for regulatory investment tests	Provides practical guidance to help network businesses apply a consistent, efficient, and effective cost benefit analysis under the current regulatory framework.	Methodology and principles	Enables more transparent and consistent application of RITs by providing guidance on stakeholder engagement and assisting NSPs in applying RITs in a changing regulatory environment.
Industry practice application note – Asset replacement planning[22]	This Application Note supplements AER guidelines by outlining principles and approaches the AER considers relevant to replacement expenditure planning. The Application Note itself is not binding, but it is intended to support NSPs in considering relevant principles and approaches that could be applied under the AER's guidelines.	Methodology and principles	The AER developed this Application Note in response to NSP requests for clarity on how they might apply the NER requirements to their replacement expenditure planning of network assets. In particular, the AER provides guidance and examples on how NSPs could meet the NER requirements of demonstrating prudency and efficiency of network investment, asset retirement and de-rating decisions.
Non-network ICT capex assessment approach[23]	The review provides clarity on the AER's approach to assessing forecast non-	Methodology and principles	The guideline is aimed at addressing a perceived gap

[20] AER, Better Regulation: Explanatory Statement – Expenditure Forecast Assessment Guideline, November 2013.

[21] AER, Electricity network service providers – Replacement model handbook, December 2011.

[22] AER, Industry practice application note – Asset replacement planning, January 2019.

[23] AER, Non-network ICT capex assessment approach, November 2019.

Guidance	Guidance description	Type of guidance	Rationale for guidance
	network ICT capex and highlights the information the AER uses to meaningfully assess ICT expenditure proposals.		regarding how ICT expenditure is assessed by the AER. Consumer advocacy groups have highlighted that the Expenditure Forecast Assessment (EFA) Guideline does not provide clear guidance on how the AER will assess ICT capex forecasts, which is a growing component of NSP regulatory proposals.
Draft cost benefit analysis guidelines[24]	The CBA guidelines provide guidance to AEMO in preparing an integrated System Plan ISP[25] and RIT-T proponents in applying the RIT-T to actionable ISP projects.[26] By doing this, the RIT-T instrument realises the purpose of the RIT-T under NER clause 5.15A.1(c), which is to identify the preferred option.	Methodology and principles	The guidelines are aimed at giving effect to the ESB rule change to convert the ISP into action.[27] The intent of the new rules is to streamline the transmission planning process while retaining rigorous cost benefit analysis.

3.3 Observations and insights

Key observations from reviewing different forms of AER guidance include:

- ***The form and level of prescription of guidance varies depending on the trigger for the guidance*** – as highlighted by Table 3, the level of prescription provided by the AER is often influenced by whether the guidance is being provided in response to a change to the regulatory framework or is self-initiated by the AER to provide clarity and/or transparency in the operation of a specific aspect of the regulatory framework.[28] Where the guidance is triggered by a change in the regulatory framework, the NER will dictate the form and level of guidance the AER is required to provide, based on the AEMC's assessment on the level of guidance most likely to promote the achievement of the National Electricity Objectives (NEO). Where guidance is self-initiated, the guidance tends to be principle-based and focused on providing worked examples

[24] AER, Draft cost benefit analysis guidelines: Guidelines to make the Integrated System Plan actionable, May 2020.

[25] AER, Draft: Forecasting Best Practice Guidelines, May 2020.

[26] Actionable ISP projects are identified in an ISP, and trigger RIT–T applications for these projects. Under the RIT–T instrument, RIT–T proponents must identify the credible option that maximises the present value of net economic benefit to all those who produce, consume and transport electricity in the market (the preferred option), consistent with clause 5.15A.1(c) of the NER.

[27] AEMC, Early implementation of ISP priority projects, Rule determination, 4 April 2019.

[28] *National Electricity (South Australia) Act 1996*, Part 3, Division 1, section 15(2) confers the AER with the power to do all things necessary or in connection with the performance of its economic and regulatory powers.

to provide greater clarity on how to demonstrate compliance with the NER requirements or AER Guidelines mandated under the NER.

- ***The form of guidance is dependent on several factors including the underlying driver for the guidance, and perceived level of uncertainty*** – where the primary driver for the guidance relates to a lack of transparency or clarity around the approach that should be followed, outlining a principle-based approach is generally appropriate as it provides flexibility in how the guidance is interpreted and applied, however it may trade-off accuracy and consistency in outcomes depending on how it is interpreted. In contrast, where the primary underlying drivers for guidance is a need for consistency in outcomes, and to address uncertainty, then a more prescriptive level of guidance such as a methodology, model, or calculation tool may be more appropriate. More prescriptive approaches do, however, involve trade-offs being made with accuracy, cost, and flexibility. While more prescriptive guidance will provide greater transparency, consistency, and certainty in outcomes, it is less likely to be robust to exogenous factors such as regulatory and market reform. The development of a highly accurate calculation or modelling tool may provide greater accuracy but is likely to be more costly and complex to implement. Depending on the circumstances, the need for accuracy may not be as important as the need for an approach that is practical and repeatable.
- ***Identifying the party to undertake the analysis is another important factor that must be considered in developing guidance that is fit for purpose*** – Ideally, the party which has the necessary capabilities, access to information, knowledge, and expertise should have the responsibility for undertaking the analysis to promote efficient outcomes. An example of this is the AER's calculation of the VCR.

Based on our observations regarding the factors that influence the type of guidance likely to be appropriate and fit for purpose, we draw the following insights:

- **Where there are opportunities to remove unnecessary duplication, as well as to provide for transparency and repeatability, it is likely to be more appropriate for the AER to set a value (i.e. adopt an approach similar to the VCR) or provide a calculation tool** – Adopting this approach is likely to promote more efficient outcomes than a principle-based or methodology approach as it addresses uncertainty, provides transparency and greater certainty in outcomes, reduces duplication, and is potentially more cost effective to implement. However, where this is the case, the value/tool requires frequent updating or revision to ensure that it is robust to changes in operating environments. Under such an approach, the AER allows DNSPs to adopt an alternative approach where this can be shown to deliver more optimal outcomes or better reflect the specific circumstances of the DNSP.
- **Where DNSPs are best placed to undertake analysis but are uncertain of the approach to follow, it is likely to be more appropriate for guidance to be in the form of a methodology rather than prescribing a value or tool** – Adopting this approach would provide more accurate outcomes and would better take into account network differences and site-specific factors given DNSPs have more granular knowledge of their network than the AER and are therefore better positioned to undertake the analysis.

Applying the above observations and insights to the issues that have been identified with quantifying DER benefits, there is a role for both principle-based guidance as it relates to consideration of benefit types, defining of the base case and approach to calculating benefits. Further, there may be a role in more prescriptive advice related to the calculation of wholesale market benefits where the AER could potentially take on a role of providing input assumptions or a calculation tool. A less prescriptive approach or methodology is likely to be more appropriate for calculating network benefits due to the high level of spatial granularity and network specific factors that need to be accommodated.

3.3.1 Investing in DER integration services

Several of the issues in valuing DER listed above stem from the 'open access' regime reflected in the existing regulatory framework, which is based on consumption (i.e. import) only and does not recognise bi-directional electricity flows and the costs/benefits derived from generation located on the distribution network. Under the open access regime there is no positive requirement for DNSPs to provide connection applicants with the ability to export, nor are there any service standards regarding exports. Consequently, without any positive requirement or obligation under the National Electricity Rules (NER), it is less clear whether DNSPs can make network investments aimed at supporting customer preferences to remove export constraints.[29]

This issue is currently being explored by the Distributed Energy Resources Integration Program (DEIP) and is the subject of current rule change requests by SA Power Networks, St. Vincent DePaul Society, and Total Environment Centre/ACOSS. The AEMC's review of these requests may increase incentives for DNSPs to support DER by making investments aimed at delivering a change in the export/import of DER systems. [30]

[29] CEPA, 'Distributed Energy Resources Integration Program – Access and pricing: Reform options,' report prepared for Australian Energy Market Commission, 9 April 2020.

[30] https://arena.gov.au/knowledge-innovation/distributed-energy-integration-program/

4 DER Value Streams

This section explores the different values streams enabled by increased DER penetration and current approaches that have been used (both in the NEM and internationally) for quantifying DER benefits. Our analysis of current approaches seeks to highlight any gaps or issues with current approaches to inform the options that we test and assess for appropriateness as part of this Study.

4.1 Overview of DER Value Streams

Table 4 lists the different value streams that may form the DER value stack[31] and indicates in which part of the energy system the benefits arise. We have collated this list from our extensive review of literature, however it is important to note that not all the value streams contained in Table 4 will be material or are able to be considered by the AER.

Table 4 – DER Value Streams

Benefit Type	Value Stream	How DER integration delivers value stream	Network investment types		
			Enable an increase in variable energy generation (passive DER)	Enable an increase in flexible energy generation (active DER)	Enable an increase in flexible generation capacity (active DER)
Wholesale market	***Avoided marginal generator SRMC***	Increased DER exports substitute for generation by marginal centralised generators, which may have higher short-run marginal costs, in the form of fuel and maintenance costs.	✓	✓	✓
	Avoided generation capacity investment	Increased DER export capacity reduces the need for investment in new/replacement centralised generators.	✓	✓	✓
	Essential System Services (including FCAS)	Increased DER import/export capacity enables more DER participation in ESS markets, reducing investment in new/replacement centralised ESS suppliers.			✓
Network	***Avoided/ deferred transmission augmentation***	Increased DER exports increases the amount of load supplied from within distribution networks, reducing peak demand at transmission connection points and avoiding or deferring transmission augmentation.	✓	✓	✓

[31] A passive DER technology can only provide variable energy services. An active DER technology can potentially provide a combination of flexible energy and capacity services. In this sense, the distinction between flexible energy and flexible capacity is not essential to understanding the conceptual value of DER. However, the distinction becomes important in the methodologies for calculating value. In simplified methods it is often practical to focus on the single most valuable type of service. The distinction also assists with identifying what costs are avoided.

Benefit Type	Value Stream	How DER integration delivers value stream	Network investment types: Enable an increase in variable energy generation (passive DER)	Enable an increase in flexible energy generation (active DER)	Enable an increase in flexible generation capacity (active DER)
	Avoided/ deferred distribution augmentation	Increased DER exports or battery imports increases the amount of load supplied from within local distribution networks, reducing peak demand at upstream network assets and avoiding or deferring augmentation of these assets.	✓	✓	✓
	Distribution network reliability	DER can supply individual customers and/or local networks after network faults, reducing unserved energy and outage duration.		✓	
	Avoided replacement / asset derating	Increased DER 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 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	DER generation supply nearby loads, reducing the distance energy travels across the distribution network compared to centralised generators, which reduces the amount of energy lost to heat when transported over distribution lines.	✓	✓	
Environment	***Avoided greenhouse gas emissions***	Increased DER generation substitutes for generation by marginal centralised generators, some of which release greenhouse gasses in the process of generating electricity.	✓	✓	
	Reduced health impacts of air pollution	Increased DER generation substitutes for generation by marginal centralised generators, some of which release noxious gasses and particulates.	✓	✓	
Customer	***Willingness to pay for other perceived benefits (e.g. self-reliance, feel good benefit, sense of contribution)***	Increased DER may provide intangible benefits to customers beyond the financial and environmental benefits– including those nearby that do not host the DER.	✓	✓	✓

Benefit Type	Value Stream	How DER integration delivers value stream	Network investment types Enable an increase in variable energy generation (passive DER)	 Enable an increase in flexible energy generation (active DER)	 Enable an increase in flexible generation capacity (active DER)
	Change in DER investment	Where a network enables additional hosting capacity, this may change the size or type of DER systems which customers invest in, compared to what they otherwise would have. Where customers invest more (e.g larger sized solar systems), this represents a negative value. Where customers invest less in DER (e.g no longer purchase batteries), this represents a positive value	✓	✓	✓

4.2 What value streams can be considered by AER

One important aspect of the methodology is determining which of the value streams above can be included. For most of the value streams identified above, this task is simple. All agree that the benefits increased DER bring to the wholesale electricity market or to the provision of network services should be included. The method of evaluating certain costs and benefits – particularly those related to DER owners and environmental outcomes – is, however, more challenging.

4.2.1 Potential system boundaries

This section considers the implications of where the system boundary is drawn in assigning costs and benefits of DER integration investments.

Three potential system boundaries have been considered to capture the long-term interests of consumers:

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.

These three approaches vary by where one draws the line in determining which costs/benefits to include. In practice, the debate is most principally between using the 'to the meter' test or the 'total electricity system' test, because the 'societal' test is outside the AER's mandate. The only difference between these two tests, as is described in more detail below, is the consideration of the costs of DER investments paid by customers/owners of DER.

The treatment of DER investment costs only changes the calculation of benefits (or our methodology) if the network varies projected DER adoption between the base case and the investment case. For the most part, we think it is unlikely that networks will – or should – change their DER adoption forecasts between scenarios, given that we suspect most network expenditure will focus on ICT investments and operational changes rather than significant expansion of network infrastructure. Networks should invest – and historically have invested – to integrate DER based on reasonable assumptions of DER adoption and not in a way that is actively incentivising additional DER adoption.

The 'to the meter' test, as its name implies, only considers costs and benefits to the system that occur up to the customer's retail meter. Accordingly, the costs of DER to the DER owner and benefits that flow exclusively to the customer (and not to the wholesale and network sectors) are excluded in this methodology.

One potential flaw with this methodology is that by not including the costs of DER to customers, it potentially overstates the benefits that investments to increase DER hosting capacity have to the system. It considers all new investment in DER created by an increase in hosting capacity as essentially free to the system, whereas the methodology does include the costs of large-scale generation. Accordingly, it serves to overestimate the benefits of network investments to increase DER hosting capacity compared to, for example, network investments to increase hosting capacity for large-scale generation. This approach is most consistent with conventional network regulation.

The second methodology – the total electric system resource test – is like the previous electric system test, except that it also includes the costs that individual DER customers pay or receive. This test essentially seeks to treat electricity customers as fully rational actors, just like those that invest in networks or large-scale generation, and accordingly includes all electricity-related costs and benefits that are incurred by these customers. By including such costs, one hopes to achieve the most efficient economic outcome. Notably, government subsidies for DER are included as a benefit in this approach; this is because DER customers (which are an included actor in this methodology) receive such benefits, whereas governments pay such costs, but are not an included as an actor in this test.

The most significant challenge with using this methodology is its practicality. When applying this approach, the accuracy of DER adoption forecasts for both a 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.[32]

The main benefit of using this methodology is that it fairly accounts for all costs and benefits incurred by all actors in the electricity supply chain. DER is by all accounts now a major source – arguably the most important source – of electricity in Australia. This approach treats the owners of that resource as actors whose full costs and benefits must be considered. In other words, this change in methodology is perhaps justified by the role DER now plays in the electric sector; continuing to exclude the costs DER owners pay would be ill advised.

The third methodology considers all of society as actors in the regulation – including governments. Aside from those outlined above, the most significant change in this approach is the treatment of environmental outcomes. In both previous methodologies, environmental outcomes were

[32] DER forecasts must be used for both the base case and investment case in all the tests identified; they are simply more important in the total electricity system test.

considered an externality unless some government policy sought to include them by posing a cost or conferring a benefit to an actor within the sector. In this methodology, all environmental outcomes are included, even if they are externalities to the market. This methodology also does not allow for government subsidies to be directly included, because subsidies represent a transfer of social/environmental benefits within the system. This approach is not recommended, simply because using it would be beyond the AER's remit.

A summary of how each test allocate value streams could is set out in Table 5.

Table 5 – Value streams included depending on system boundaries

Cost/Benefit Category	Electric system up to the meter test	Total electric system resource test	All of society test
DER benefits to wholesale market	Included	Included	Included
DER benefits to network sector	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 (including both DER and non-DER)	Included even if no gov't imposed costs/benefit
Other perceived (intangible) DER benefits	Excluded	Excluded	Included
Change in DER investment	Excluded	Included	Included
Government subsidies for DER	Excluded (all DER costs and subsidies excluded)	Excluded[33]	Excluded

What does the NER/NEL say?

The National Electricity Law (NEL) requires the AER to perform its economic regulatory functions in a manner that will or is likely to contribute to the achievement of the National Electricity Objective (NEO):

> *…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 to the benefit of electricity consumers in the long-term. The value streams that the AER may consider therefore must ultimately transfer to electricity consumers in the long-term.

[33] For clarity, this implies that for any additional DER, the subsidised amount should be subtracted from the DER cost. This is consistent with the approach for RIT-T whereby any portion of a network investment that is government subsidised is excluded from the cost.

The RIT-D application guidelines provide further guidance on the types of value streams which can be considered by the AER. The RIT-D guidelines state that any DNSP investment must be shown to increase *consumer and producer surplus* in the NEM where:

- consumer surplus is the difference between what consumers are willing to pay for electricity and the price they are required to pay
- producer surplus is the difference between what electricity producers and transporters are paid for their services and the cost of providing those services.

The RIT-D application guidelines further set out the types of benefits that may be considered to increase consumer and producer surplus including reductions in:

- capital costs, including the costs of generation and network assets
- operating costs, including fuel costs, network losses, ancillary services, as well as voluntary and involuntary load reduction
- where applicable and material, the costs of meeting mandated government targets, such as the renewable energy target (RET) or similar developments (like a potential National Energy Guarantee or similar).

Based on the above, we consider 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.

4.2.2 Proposed treatment of environmental and health benefits

Environmental and health benefits are likely to be considered by the AER as externalities that accrue to parties other than those who produce, consume or transport electricity in the market. Adopting the total electric system resource test, these value streams are only likely to be included to the extent that market participants in the NEM may need to, in a particular scenario, pay a tax, levy or other payment associated with environmental or health costs or where jurisdictional legislation directs DNSPs to consider the impact of these externalities and has provided a value that is to be used (e.g. a jurisdictional requirement to consider the price of carbon).

4.2.3 Treatment of intangible benefits of DER

Intangible benefits (beyond environmental and financial) are excluded under both electric system tests. These intangible benefits may manifest as either:

- A DER owner's willingness to pay a premium for investment in DER, or
- A DER owner's (as a producer of electricity) willingness to accept reduced revenue.

It is unclear whether a DER owner's willingness to pay a premium for DER is strictly an *electricity* consumer surplus as many or most of these values may be unrelated to the electricity system impacts of DER. It is further unclear that these intangible benefits represent an electricity producer surplus, unless the DER owner (as a producer of electricity) is willing to make a loss on their investment (such that the acceptable revenue is below the cost of their investment).

We acknowledge 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[34], and our assumption is that the value of intangible benefits not already captured within the methodology is small.

Moreover, in practice it is complex to capture the additional consumer willingness to pay for additional access to exports/imports beyond the value streams already captured. For the purposes of this study, we suggest that the value of intangible benefits not otherwise accounted for by our methodology should be excluded.

4.2.4 Treatment of avoided DER investment costs

For the purpose of this Study, we have considered that DER owners are producers of electricity and suggest including avoided DER costs.

In this sense, we draw boundaries around our system to include the consumers' electricity assets behind the meter, to the extent that a change in investment in behind the meter assets gives rise to a benefit or cost within the electricity system.

Some stakeholders did not necessarily agree with this approach, arguing that DER costs should be excluded as they are not entirely paid for by all electricity consumers (noting that they are partly paid for by all consumers where any feed-in tariff is in place). Others also suggested that DER investment costs can also include some intangible, additional willingness to pay, beyond that of an economically rational customer, and that this intangible cost should not be included unless the intangible benefit was also included.

In our view, the existence of a premium payment for intangible benefits above may be true for early adopter markets and so may potentially apply for battery investments. Where a network is able to identify (or makes an assumption) about the premium customers pay for DER systems (above economically rational), this may be subtracted from the DER costs they include in their cost-benefit assessment.

We also consider that any DER subsidies that the customer receives should be netted off from investment costs, consistent with the treatment of environmental and health benefits above.

4.3 How value streams translate into customer benefits

While this Study is not focussed on the apportionment of DER value between producer and consumer surplus, or the apportionment of those surpluses between individual customers/producers, the value streams discussed above may transfer in part or in full to both DER and non-DER customers.

Wholesale market benefits (avoided marginal generator SRMC and avoided generation capacity) are initially captured by the DER customer through their feed-in-tariff. Over time, competitive

[34] Energy Consumer Australia, Consumer Sentiment and Behaviour, 2019

pressures in the wholesale market may transfer some of these benefits to non-DER customers through lower wholesale electricity prices.

Essential System Services benefits would generally transfer directly to the DER customer and/or aggregator through service payments where there is an existing market (e.g FCAS). As with wholesale market benefits, over time competitive pressures may transfer some of these benefits to non-DER customers through lower service prices.

Network benefits are transferred to all customers supplied by that network via reduced network prices. A portion of the benefits may be captured by specific DER customers in the form of availability (or similar) payments made by the network to source network support services. These benefits are provided only to the subset of DER customers that actually provide a network benefit. The extent to which the remaining benefits (i.e. where payments for services are less than the value of avoided network augmentation) are shared by all DER and non-DER customers depends upon the network tariff structure.

5 VaDER Methods

5.1 Principles for Method development

Value of DER (VaDER) methods are methods for calculating the value delivered by a change in DER generation and/or capacity as a result of a DNSP investment.

Based on the regulatory framework and diversity of applications, the following principles have been developed and applied to determine fitness for purpose:

- Able to quantify changes in consumer and producer surplus over the network investment lifetime
- Likely to give rise to near optimal levels of investment by NSPs by:
  - Being sufficiently granular (temporal) to reflect that the additional DER generation is likely to vary depending on time of day
  - Being sufficiently granular (spatial) to reflect that benefits will differ depending on the location of the investment
  - Accounting for changes in the energy system over the network investment period
- Flexible enough to accommodate jurisdictional differences, future market reforms, and differences in network visibility and access to data
- Proportionate (in terms of cost and time to undertake) with the levels of expenditure likely to be proposed
- Practicable for the DNSP to apply.

5.2 Existing Methods

5.2.1 Other contexts

There have been several studies both in Australia and internationally which set out approaches for valuing DER benefits. Most of these studies have been prepared for applications which differ from the context described here, most commonly to set feed-in tariff rates for DER customers. These methods tend to:

- Reflect short-term value (rather than value across the longer-term period of the network investment)
- Reflect the full value of all DER exports (rather than just the fraction of DER exports enabled by the network investment, which may not necessarily match the profile of the overall DER export)
- Not consider a counterfactual (or assume a counterfactual of no DER)
- Focus predominantly on wholesale market benefits
- Require network benefits, when considered, to be determined through a separate process and/or by the network internally.

Nevertheless, these studies provide valuable insights into the methods various parties have used to determine the value of DER. In particular, the use of shorthand methods to calculate wholesale market benefits. The review of other Methods reviewed is set out in Appendix D.

5.2.2 Methods adopted by Australian NSPs to date

Methods adopted by networks in Australia to date, specific to justifying network investment in DER integration, have generally only been concerned with investment that enables energy services (as opposed to capacity) and have taken one of two approaches:

- Use of electricity market modelling to assign a value to the wholesale market benefit of increased DER generation enabled by the network investment; or
- The use of a constant rate (usually $ per kWh) from an external source (e.g. Victorian feed-in tariff) assigned to the increased DER export/generation enabled by the network investment.

Of the NSPs that have to date submitted business cases, only one has included any network benefits based on increasing the lifespan of network assets due to reduced utilisation[35] (included as avoided replacement / asset derating in the value streams identified in this study).

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 overtime 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.

Electricity market modelling

Electricity market modelling, for the purposes of identifying wholesale market benefits is likely to be fit for purpose where:

- The model is tried and tested;
- The model uses input assumptions from valid, referenced external sources; and
- The cost of the modelling is proportionate to the level of investment proposed.

Electricity market modelling, however, tends to lack transparency and is sensitive to bidding behaviour assumptions embedded in proprietary models which vary depending on the model used. As a result, the AER and other stakeholders may find it challenging to assess the appropriateness of the value of DER derived.

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[35] Jemena Electricity Networks, 2021-26 Electricity Distribution Price Review: Regulatory Proposal: Attachment 05-04 -Future Grid investment proposal, 31 January 2020

Though recommended by the RIT-T and RIT-D, the use of sophisticated electricity market modelling in the context of DER integration investment is not necessarily required. DER integration investments by individual networks give rise to additional DER generation. However, for some projects, additional DER levels may not materially impact market investment outcomes. In these cases, an electricity market model is useful in deriving assumptions about the market at the time the additional DER generation occurs or capacity is enabled, which may then form inputs to cost-benefit assessments. However, for low levels of additional DER, the model does not necessarily need to be "run" to determine the impact of the additional DER on the system. A credible set of assumptions with respect to the future operation of the electricity market (which are derived from an electricity market model) is likely to be sufficiently robust. For example, if AEMO were to publish wholesale price or short-run marginal cost outcomes from its electricity market models (for the ISP central scenario) on a half-hourly basis over a 50 year period (which it currently does not do), then these AEMO modelled outcomes could be credibly used as inputs into an NSP cost-benefit assessment without the need for a network to commission an electricity market modelling exercise.

Constant rate from external source

The use of a constant rate from an external source (such as a feed-in tariff) is not likely to be fit for purpose, especially where the constant rate was developed for another context. This is due to:

- The constant rate not being able to reflect future changes in the electricity market (which are very likely to be significant);
- 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 (as opposed to, for example, a standard solar profile, which is often assumed under feed-in tariff calculations); and
- The constant rate including components which may not fall within the boundaries of consumer and producer surplus (such as environmental benefits, and financial costs to retailers such as market fees).

5.3 Proposed Methods

The methodology developed for determining the value of an increase in hosting capacity compares the total electricity system costs as a result of increasing hosting capacity with the total electricity system costs of not doing so. In other words, the method compares investment, operations, and environmental outcomes in a "base case" and in an increased hosting capacity case.

The value can be calculated as the difference in investments, operation, and environmental outcomes between the increased hosting capacity scenario and the base case. Investment costs are expenditure on long-lived assets such as generation technologies, network infrastructure, and customer DER. Operating costs include fuel and maintenance costs and are impacted by changes in the timing of the operation of other participants in the sector (hence changes in behaviour are also relevant in this category of expenditure). Environmental outcomes focus primarily on changes in emissions of greenhouse gases and other pollutants.

The method can be described mathematically:

$$Value\ of\ an\ increase\ in\ DER\ hosting\ capcity = Investment\ costs_{(inc\ hosting\ capacity)} + Operating\ costs_{(inc\ hosting\ capacity)} + Enviro\ outcomes_{(inc\ hosting\ capacity)} - Investment\ costs_{(BAU)} - Operating\ costs_{(BAU)} - Enviro\ outcomes_{(BAU)}$$

Both the base case and the increased hosting capacity scenario include some amount of investment cost and operational cost – in large-scale generation, capacity for essential system services, in network, and in DER by customers.

Our proposed methodology requires networks to carefully and clearly articulate their assumptions about the changes in investments, operations/behaviours, and environmental outcomes in both the base case and the investment scenario.

5.3.1 Determining DER services enabled by the network investment

<u>*Type of DER service enabled*</u>

The type of DER service enabled by a network investment dictates the benefits available, and we describe the three germane DER services – variable energy services, flexible energy services, and capacity services – below. Determining which of the three types of services are enabled requires consideration of the impact of the investment.

- **Variable energy services** will be enabled by investments that increase the overall capacity of *passive* DER in the network (such as solar PV) either by creating incentives which give rise to more and/or larger passive DER systems and/or by directly enabling additional export capacity for passive DER.
- **Flexible energy services** will be enabled by investments that increase the overall capacity of *active* DER (e.g batteries or V2G EVs) in the network where these systems predominantly provide wholesale or retail price arbitrage. This may be either by creating incentives which give rise to more and/or larger active DER systems and/or by directly enabling additional export capacity for active DER.
- **Capacity services** will be enabled by investments that increase the overall capacity of active DER (e.g. batteries or V2G EVs) in the network where these systems predominantly provide capacity services (e.g. frequency control and ancillary services and/or essential system services). This may be either by the investment resulting in an increase in the number or size of active DER systems and/or by enabling additional export capacity for active DER.

In most cases, where active DER is enabled, both flexible and capacity services will be provided. However, the shorthand method requires the network to evaluate one service at a time. The first service selected should represent the service via which the active DER systems are likely to generate most of their revenue. Networks can choose to stack additional benefits from other services if necessary, to support the investment case.

In some cases, one service may be enabled while another is reduced. For example, a network investment may allow for increased export limits for variable energy services by reducing the amount of inverter tripping. However, the investment may also reduce investment in batteries (a customer solution to reduce inverter tripping) which may have otherwise occurred, reducing flexible energy and/or capacity services. As a result, the investment will both enable variable energy and reduce flexible energy or capacity services. Where these changes are material, the change in all services should be considered.

Volume of DER services enabled

Determining the volume of DER services enabled is a complex exercise and highly dependent on the type of network investment. The following considerations must be made when determining the volume of DER services enabled:

1. Produce a baseline forecast of DER adoption in the network in terms of number, capacity and type of DER systems adopted over the investment life (for the base case without an investment in additional hosting capacity)
2. Produce aggregated half-hourly generation profiles (for energy services) and/or total aggregated flexible capacity (for capacity services) of the DER systems corresponding to the baseline forecast over the investment lifecycle
3. Identify how the network investment will change the way in which customers adopt DER systems in terms of number, capacity and type of systems relative to the baseline
4. Produce an aggregated half-hourly generation profile (for energy services) and/or total aggregated flexible capacity (for capacity services) of the DER systems under the network investment case over the investment lifecycle
5. Produce a net half-hourly generation profile (for energy services) and/or total aggregated flexible capacity (for capacity services) that has been enabled by the network investment by comparing 4) to 2).

Where network benefits are included, consideration must also be given to the spatial variation in volume of DER services enabled.

Two additional clarifications may be helpful: first, determining how a network investment impacts DER adoption by customers (in 3. above) is outside of the scope of this project, but would generally require a model and/or assumptions which forecast customer DER uptake based on price/incentives offered. Second, the half-hourly operation of flexible capacity is a function of capacity market prices which are more variable and uncertain than energy. While capacity markets continue to mature, in the interim, it is acceptable at present to establish the likely capacity available when capacity services are required rather than a full yearly profile.

5.3.2 Quantifying wholesale market \ benefits

We have proposed both a longhand and shorthand method for quantifying wholesale market benefits.

Shorthand vs Longhand approaches

We use the terminology “longhand” to describe electricity market modelling as provided by various consultants using bespoke software and “shorthand” to describe methods that can be carried out using simple, readily-available spreadsheet software and data either created by the network or in the public domain. The shorthand method is a simplified method which does not require electricity market modelling and is generally conservative

Where appropriate, the methods include both a shorthand and longhand method. It is proposed that a shorthand method may be used:

- 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.

The first two criteria should both be met to qualify.

Proposed Methods

We have proposed both a longhand and shorthand method for quantifying generation sector benefits.

The longhand approach involves commissioning electricity market modelling. Electricity market modelling will enable the impact of the change in DER services on the wholesale market to be quantified in terms of both avoided investment and avoided operational costs.

Two shorthand approaches are proposed in Table 6.

Table 6 – Shorthand approaches to quantifying generation sector benefits

Approach	Description	Applicable DER Services	When it should be applied	Inputs required
Total cost method	Evaluates the avoided investment in the wholesale market by considering the total (long run marginal cost) of the corresponding technology investment avoided	Variable energy Flexible capacity	When the additional DER variable energy or flexible capacity is: • available over an extended period • demonstrably needed by the sector in that generation region based on future planning • (for variable energy only) the annual energy profile a reasonable substitute for the relevant standard solution(s) to be avoided or reduced.	Long run marginal cost of large-scale generation technology in which investment may be avoided by the enabled DER services
Running cost method		Variable energy Flexible energy	When the total cost method is not applicable and/or flexible energy services are enabled	Wholesale market prices (as a proxy for short run marginal cost) for the previous year with a discount factor applied over time adjusted over time to account for likely changes in average prices in the relevant time period.

Further explanation of the shorthand methods including detailed formulae are contained in Appendix E. Worked examples of both shorthand methods are contained in Appendix F.

5.3.3 Worked example variable energy services: Generation running cost method-reduced rooftop solar tripping in system with 5kW export cap

The case of increased hosting capacity to reduce inverter tripping was selected as one worked example, because inverter tripping is a widely recognised outcome of constrained hosting capacity. In this case, large-scale solar PV was considered as a potential substitute for the additional rooftop solar. In Appendix E we explain that comparing capacity factors of the additional DER output to its nearest large-scale competitor can be used to screen the potential for substitution.

The capacity factor ratio – which compares the generation capacity of the investment-enabled, additional tripped solar to large-scale solar generation it might displace – is very low at 0.15 to 0.17 (also see Figure 7). As such the case of avoided investment is very weak – the additional solar enabled by the network investment only unlocked 15-17% of the output of an equivalently sized large-scale solar installation. Therefore, the generation running cost method is appropriate. (The additional value from rooftop solar meeting environmental requirements in Victoria and Queensland are ignored for now but are addressed in Appendix F.) For simplicity, we also exclude changes in battery investment that might occur; combined solar and battery investment and operation changes are examined in the next example.

Networks will calculate their own expected additional DER output profiles from studying their own networks. For the purposes of presenting a worked example, we constructed a synthetic profile for additional rooftop solar that has been allowed by increasing hosting capacity – this is the solar generation that would have occurred if the inverter had not tripped due to voltage increases beyond the inverter's threshold. This synthetic profile was created by keeping all output from the normal rooftop solar profile during weekend and public holidays between 10am and 3pm and deleting output at all other times. This approach assumes most tripping of rooftop solar PV generation occurs on low demand times and days during high solar output. The business as usual tripped profile and the now avoided amount of tripped energy is shown together in Figure 6. This avoided tripped energy is also shown as normalised average daily generation profile in Figure 7 and compared to large-scale solar PV average daily generation.

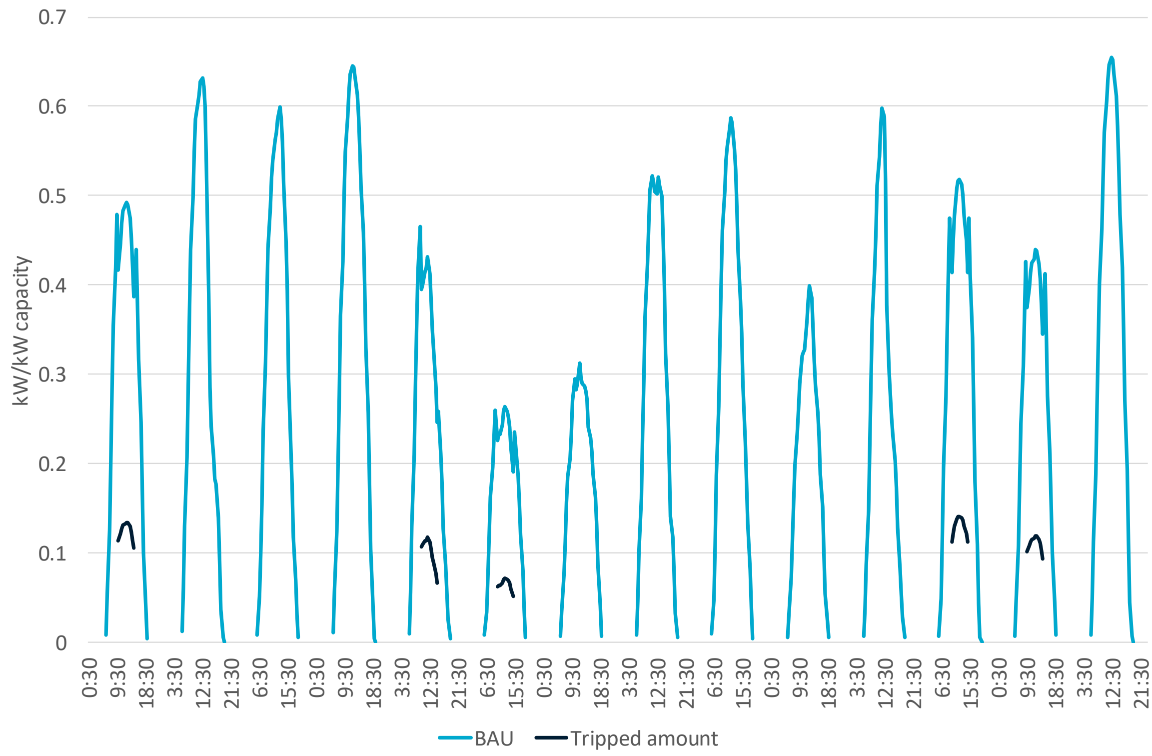

Figure 6 Sample of synthetic profile of rooftop solar tripping under business as usual and tripped amount

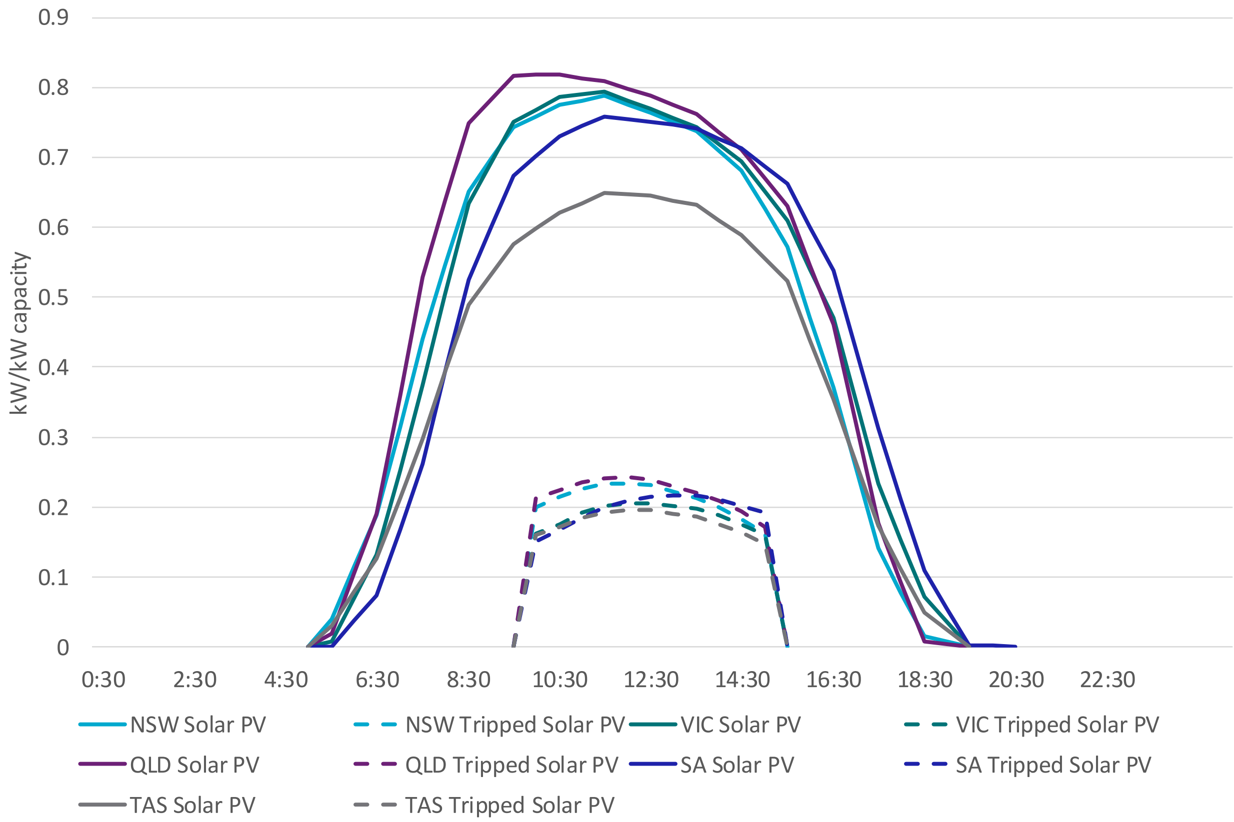

Figure 7 – Total cost of large-scale solar PV and value per MWh of additional rooftop solar PV under generation total cost method

To apply the generation running cost method, historical half hourly regional electricity prices have been collected for both calendar year 2019 and financial year 2019-20 (the complete formula for the method is shown in Appendix F). Figure 8 shows the percent of times between 9am to 5pm that each of the NEM regions experienced negative prices during these one-year periods. The relative prevalence of negative prices during the day reflects a combination of factors including increased deployment of rooftop and large-scale solar PV, low industrial demand in the region, the state of demand in neighbouring regions and more random factors such as the incidence of mild clear days on weekends and public holidays. The increase in negative prices in 2019-20 also reflects the one-off factor of reduced demand due to the imposed shutdown in economic activity to manage the COVID-19 pandemic.

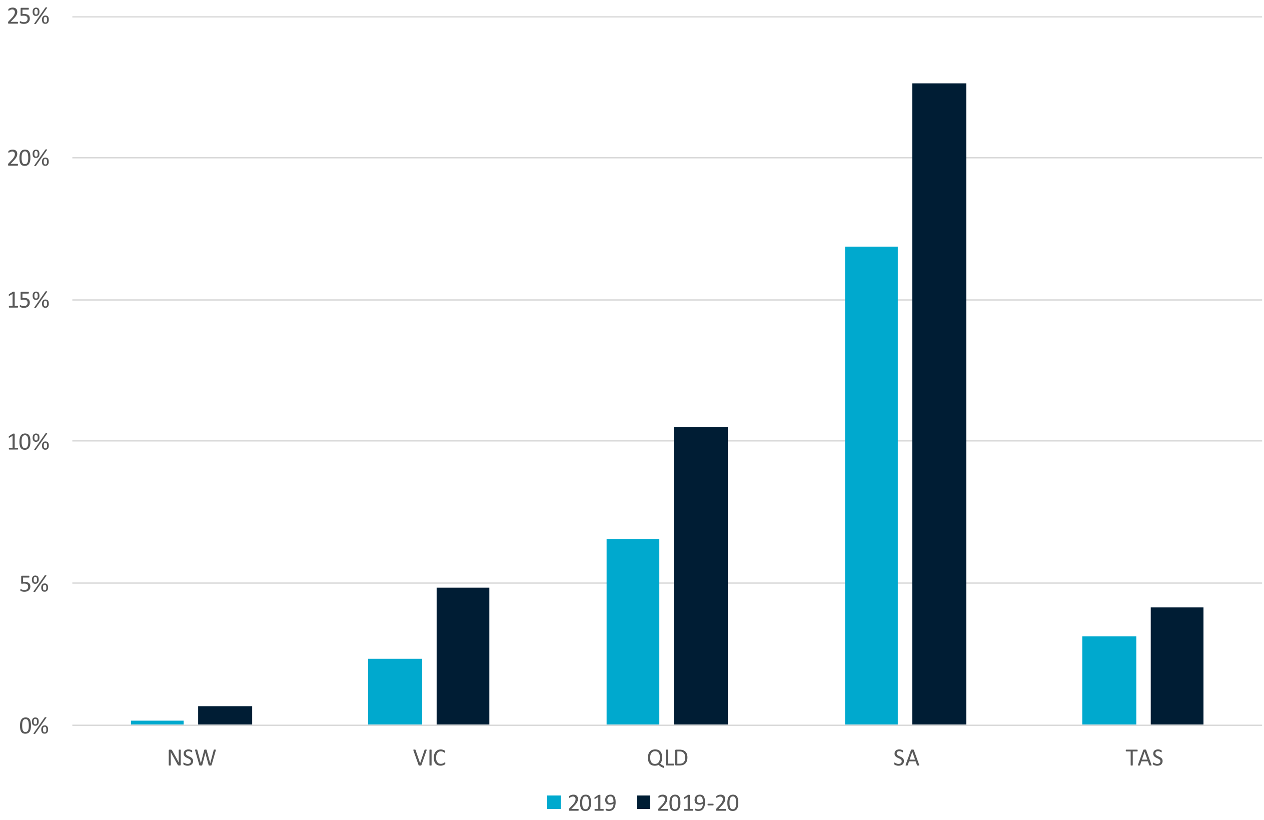

Figure 8 – Proportion of time region experienced negative 30-minute prices by region and period

The most recent historical half hourly prices are used in the formula as a starting point but must be adjusted over time to account for likely changes in average prices in the relevant time period (Figure 9). There are no regular half-hourly or annual electricity price forecasts provided by AEMO or other groups. Should a source of this data emerge, it is the most preferred source.[36] Otherwise, a source that reflects changes in costs of electricity supply at the relevant time period should be used. For the trend in prices that would be received by rooftop solar PV, an index of the change in the total costs of large-scale solar should be used[37]. Our expectation is that the average value of all

[36] We separately suggest AER consider commissioning annual market modelling to provide such a source of data.

[37] Large-scale solar is projected to be the most competitive supplier in this time period over the long run and so it is reasonable to expect volume weighted prices during this period will converge towards the cost of large-scale solar. The index is applied directly to the volume-weighted average rather than the individual prices as it makes more sense in this context.

prices combined will fall overtime. Accordingly, the index is used as an annual adjustment factor of the summed value of half hourly prices in the first year. Applying this approach, the present value over 30 years of 1 MW of additional DER is $174,000 to $295,000 using historical 2019 calendar year prices as starting prices, and $41,000 to $175,000 using historical 2019-20 prices as starting prices. We do not consider the cost per MW of implementing the increased hosting capacity that made the tripped rooftop solar PV available. Therefore, we cannot say whether this level of wholesale market benefits would be sufficient to justify the network hosting capacity project.

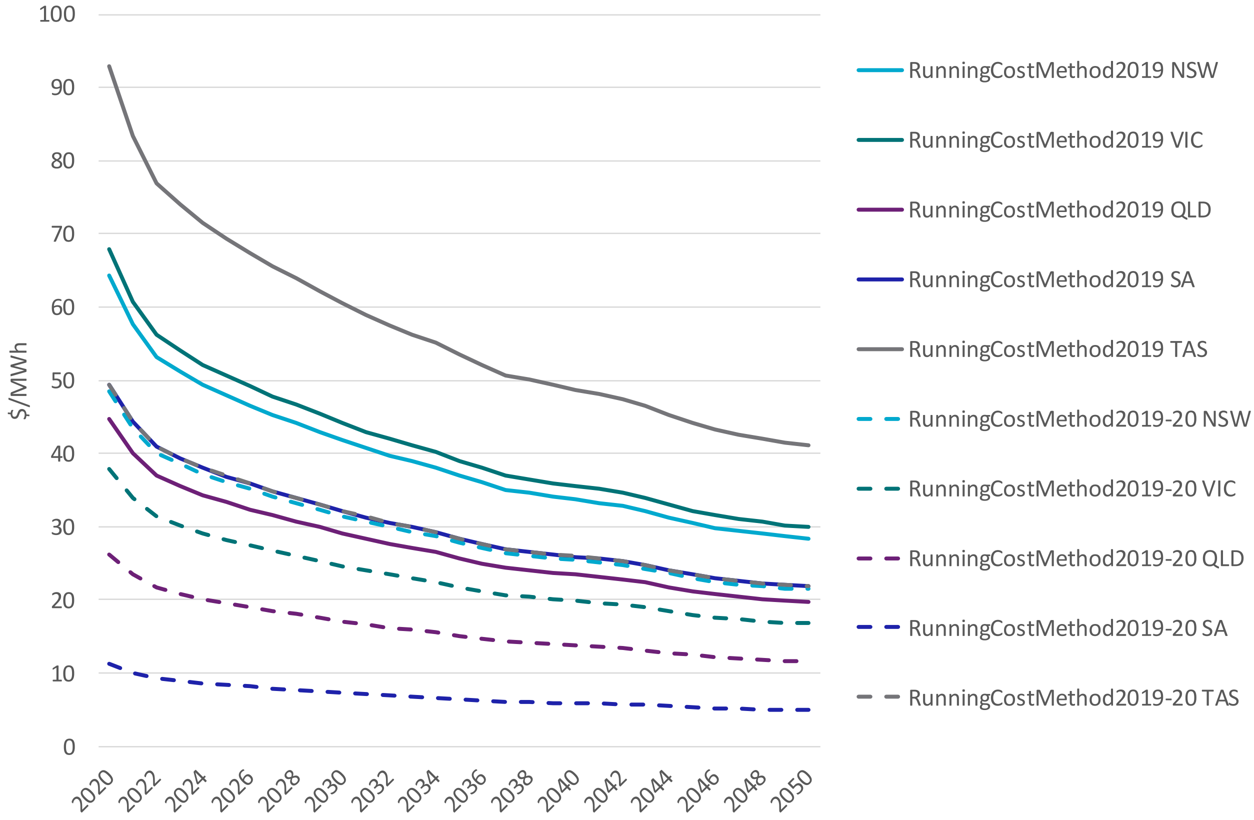

Figure 9 – Average value of avoided running costs to 2050 for starting years 2019 and 2019-20

5.3.4 Worked example combined energy and capacity services: Generation total cost method- static 5 kW export limits converted to static 10 kW limits for VPPs

In this example, increased hosting capacity is made available for rooftop solar and battery systems to operate in the wholesale market as a VPP system with an increased export capability from 5kW in the BAU to 10kW in the investment case. These are static export limits because we do not have access to data on dynamic limits.[38]

A sample of the simulated net export profiles is shown in Figure 10. The optimisation resulted in the selection of larger solar and battery systems to make use of the additional export capacity and

[38] Were such data available, the same methodology choices apply. The profile should be examined to determine whether it avoids large-scale investment because it has a similar profile to large scale technologies or whether it avoids running costs. While there is no data available, our expectation is that the profile would be narrower and flatter than a static change in export limits because the rooftop solar would only be able to access the extra export capacity less frequently. There might also be less additional investment above the business as usual for the same reason. This may support using the running cost method.

minimise customer energy costs. This means that we are likely to see some customers choose to invest in larger systems than they would have in the business as usual scenario.

The difference between the 5kW and 10kW export limit battery profiles represents the total impact on the generation sector and is shown in Figure 11 as an average daily profile of differences in net exports. It shows that with an additional 5kW export capacity, batteries in all states would increase their exports during the morning and evening peaks when wholesale prices are higher (with the exception of Tasmania where prices appear to be more attractive during daytime). It can also be said that states generally increase exports throughout the day except in NSW and Victoria where there appears to be an advantage in reducing exports in the middle of the day, perhaps to have more battery charge available for higher priced periods prices outside this time.

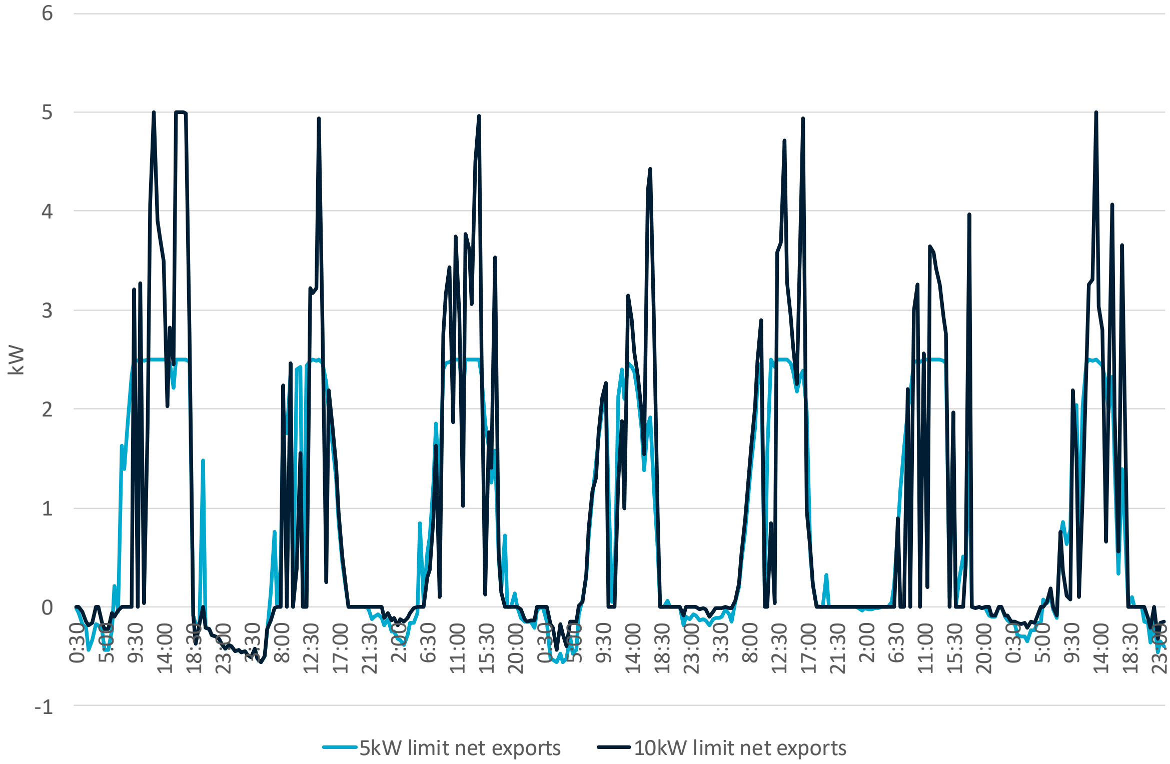

Figure 10 - Comparison of BAU 5kW limit and increased hosting capacity enabled 10kW limit VPP sample net export profiles, NSW

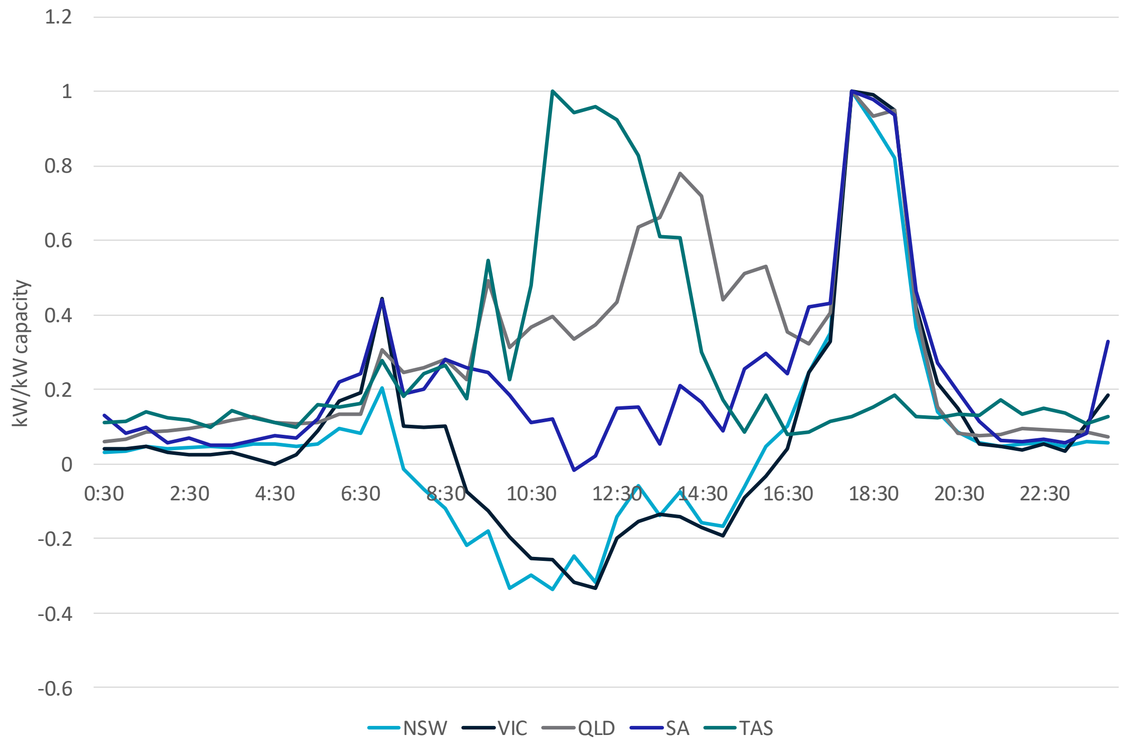

Figure 11 – Average daily profile of difference in net export profile of BAU 5kW limit and increased hosting capacity enabled 10kW limit VPP

The most appropriate large-scale generation technology to provide a substitute value for this additional DER is large-scale solar with large-scale batteries of around two hours duration. In the case of solar without a battery, we show an example in Appendix F where it is possible for rooftop solar investment to provide a positive benefit from replacing large-scale solar investment. This is largely because rooftop solar costs are subsidised by Commonwealth policies in 2030 in all states and some states add additional state-based subsidies. These subsidies are designed to encourage adoption of these technologies and therefore should not be included as costs[39].

However, when battery and solar are combined, small-scale systems are not competitive with large-scale solar and batteries. This is because batteries are a significant extra capital cost for small-scale systems which is not compensated for by significant extra subsidies. The impact of these higher capital costs for rooftop systems are compounded by a low capacity factor compared to large-scale solar (because they include single axis tracking and are better positioned). The Victorian government does have a scheme whereby a subsidy of $4174 is available for a limited number of batteries. The effect of this subsidy is included in the range shown in Figure 12. As this is a flat subsidy, we also calculated the system costs for a smaller system, from 10kW to 7kW. This was not enough to make rooftop solar and batteries competitive with its large-scale substitute.

[39] On the principle that a method should not be designed to undermine government policies.

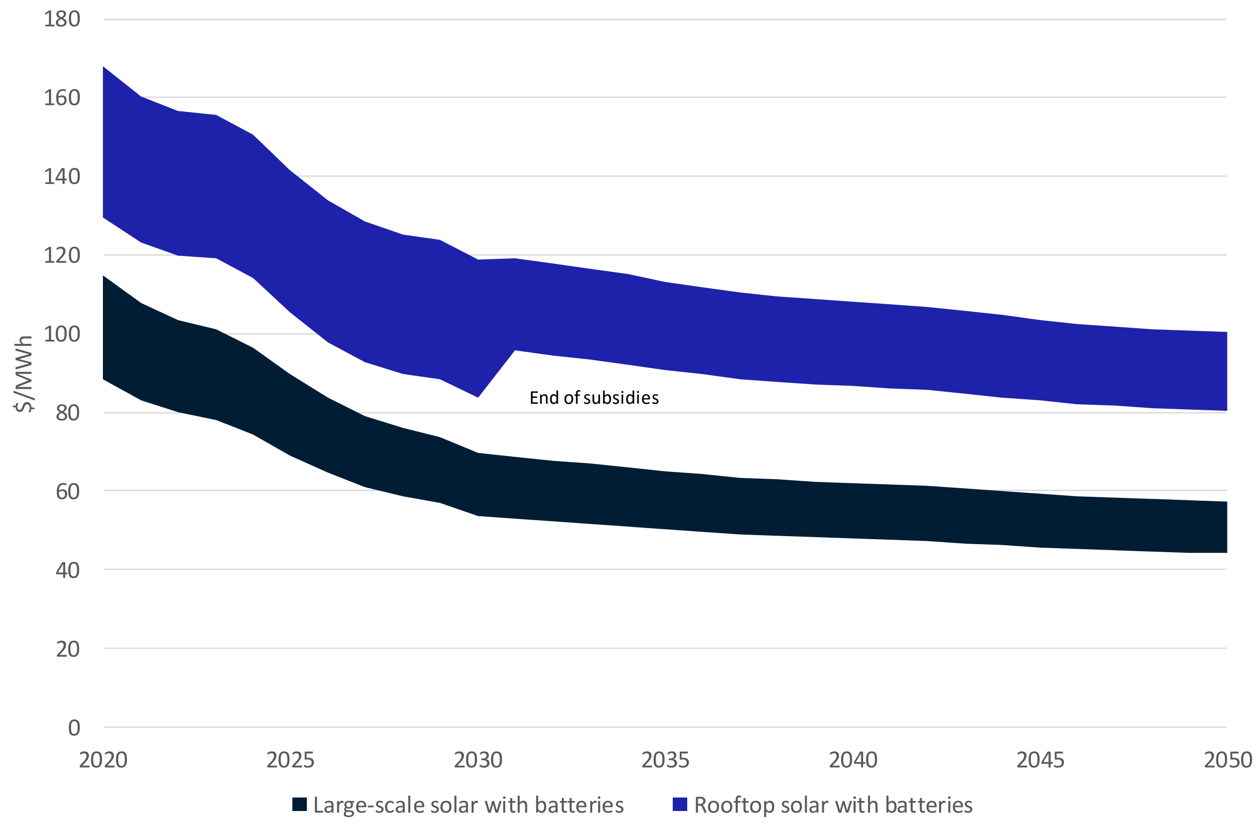

Figure 12 – Comparison of the levelized costs range of rooftop solar with batteries and large-scale solar with batteries

Given the relative costs of the two competing technologies there is no generation sector benefit to be found from investment in solar-battery systems above the business as usual to take advantage of higher export limits. They would only displace lower cost investment in large-scale systems. However, all solar-battery systems that existed in the business as usual and that are large enough to use the extra capacity (and are currently limited in their operation by the existing export limit) would provide benefits. The benefit of all additional energy provided is $88/MWh to $114/MWh in 2020.

However, given that the number of large existing batteries may be limited, perhaps a larger resource in the business as usual is electric vehicles which we explore in the next example

5.3.5 Worked example combined energy and capacity services: Generation total cost method- static 5 kW export limits converted to static 10 kW limits for electric vehicles

In this example, the network has identified customers in the business as usual that will purchase electric vehicles mainly for transport services of a certain range (battery capacity) but it has a vehicle to grid capability that is potentially large. Consequently, expanding export limits might provide more flexible energy or capacity services to the wholesale market from DER that already exists in the business as usual.

The expansion of the export capacity provides additional flexible energy and capacity that competes with large-scale batteries. We focus on the capacity component of this combined service. We could also include the energy as part of the technology package by valuing the net change in energy exported each day, but this is likely the smaller of two value streams because the throughput potential of the storage has not changed. While we do not include the energy value, networks can choose to include it if the capacity value alone is insufficient to establish the investment case. A total generation cost method is the appropriate valuation method since it is likely the availability of the increased DER capacity could reduce the need for large-scale flexible capacity.

Networks will need to conduct simulations to determine the duration of the use of the additional DER capacity in order to select the duration of large-scale battery they will be avoiding. Longer duration batteries are more costly, accordingly, additional DER with longer operation will provide greater benefits. For this example, the additional DER capacity avoids the need to build some four-hour, large-scale batteries which would otherwise have discharged into the peak evening period (which under the simulations in the previous example was the most attractive use of the capacity in most states). Based on GenCost 2019-20, four-hour, large-scale batteries are $1964/kW or $1,964,000/MW in 2020 (Graham et al., 2020). Given the example may relate to vehicle to grid which may not be deployed in substantial numbers for another decade, the 2030 value of $828,000/MW, which accounts for further reductions in the cost of large-scale batteries, may be more relevant.

It is possible this capacity might also provide a network benefit where the vehicle battery operation aligns with network peak demand reduction or if it is incentivised to provide capacity services in both markets. The average cost of network capacity is the relevant benefit metric in this case. Adding benefits across or within sectors rests on the network providing evidence of vehicle battery capacity being able to plausibly operate in this manner and assigning only the capacity that was used in those separate markets to their respective benefits.

5.3.6 Quantifying network sector benefits

For network value streams, we identified whether existing approaches set out in the RIT-D guidelines or other AER guidance are fit for purpose or whether additional guidance or shorthand approaches can be specified, especially where the investment is at the program level and location-specific information is not necessarily known.

Table 7 summarises the proposed approach for each network benefit type:

Table 7 - Approaches to quantifying network sector benefits

Network benefit	Applicable DER Services	When the value stream should be considered	Proposed treatment
Avoided/deferred transmission augmentation	Passive energy Flexible capacity	Where: • peak demand is growing at transmission BSPs • (for passive energy) peak demand coincides with times when passive DER generation is enabled.	**Known short-medium term transmission constraint**: As per RIT-T guidelines Section A.4. **No known transmission constraint:** 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, estimated from historical demand growth and augmentation expenditure data (a proxy may be the monthly demand charge at the relevant BSPs that the TNSP charges DNSPs).
Avoided/deferred distribution augmentation	Passive energy Flexible capacity	Where: • peak demand at an upstream point on the distribution network is growing • peak demand coincides with times when DER exports are enabled.	**Known short-medium term distribution constraint:** As per RIT-D guidelines Section A.4. **No known distribution constraint:** Each kW of reduced peak demand is valued at the annualised LRMC of the distribution network, estimated from historical demand growth and augmentation expenditure data.
Distribution network reliability	Flexible energy	Where: • the investment by the network includes or incentivises additional investment in battery storage (which would not otherwise 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 valued using the appropriate VCR value.
Avoided replacement / asset derating	Passive energy Flexible capacity	Where: • peak demand is not growing over time at the relevant network asset • peak demand coincides with times when DER exports are enabled.	As per *AER Industry practice application note Asset replacement planning*

		• network asset longevity and/or maintenance costs can be improved by reducing loads	
Avoided transmission losses	All	All	Avoided transmission losses should be built into the calculation of wholesale market benefits. This can be done by using the published MLF for the bulk supply point the relevant local distribution network is connected to. The avoided losses themselves are not an economic benefit, but the avoided generator SRMC or LRMC is an economic benefit.
Avoided distribution losses	All	All	Avoided 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 or LRMC is an economic benefit.

5.3.7 Consideration of Environmental Benefits

As set out in Section 4.2, we propose that environmental benefits are only included where 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 (e.g. a jurisdictional requirement to consider the price of carbon).

In Australian jurisdictions, there are two potential environmental policy mechanisms that may give rise to system costs which may be avoided. These include:

1. Renewable energy targets: existing targets in place in some jurisdictions (ACT, Victoria, Queensland, Northern Territory (NT)).
2. Carbon price for generators: currently not in place in any jurisdictions (although various forms have existed in the past or been proposed. Potential mechanisms include carbon tax, cap and trade or baseline and credit which result in an additional operational cost to non-renewable generation.
3. Jurisdictional requirement to consider the price of carbon.

Where either of the first two policy mechanisms are in place, the impact of the policy should be incorporated into the approach used to determine the wholesale market benefits. The way in which each of these mechanisms should be incorporated into the valuation approach is set out in Table 8.

Table 8 – Incorporation of environmental policies

Policy Mechanism	Shorthand – Running Cost	Shorthand – Total Cost	Longhand
Renewable Energy Targets	Reflected in wholesale energy prices used	For passive energy, any additional DER generation may offset centralised renewable generation (regardless of profile)	Included as a constraint
Carbon price	Reflected in wholesale energy prices used	NA	Reflected in operating costs of individual generators

The final mechanism does not impact the wholesale market, but rather requires the network business to calculate the carbon benefits associated with its investment. Where this is the case, the network 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 ISP Central Scenario.

5.3.8 Value stacking

Table 9 below summarises the benefits which may be included and the applicable methods for each DER service enabled.

Table 9 – Benefits and applicable methods for each DER service enabled

<table>
<tr><th rowspan="2">Benefit Type</th><th rowspan="2">Value Stream</th><th colspan="3">Network investment types</th></tr>
<tr><th>Enable an increase in variable energy generation (passive DER)</th><th>Enable an increase in flexible energy generation (active DER)</th><th>Enable an increase in flexible capacity (active DER)</th></tr>
<tr><td rowspan="3">Wholesale market</td><td>Avoided fuel and maintenance costs</td><td rowspan="2">Applicable to all investments
Electricity market modelling or shorthand (total costs or running costs method)</td><td>Applicable to all investments
Electricity market modelling or shorthand (running costs method)</td><td>NA</td></tr>
<tr><td>Avoided generation capacity investment</td><td>Applicable to all investments
Electricity market modelling or shorthand (total costs method)</td><td rowspan="2">Applicable to all investments
Electricity market modelling or shorthand (total costs method)</td></tr>
<tr><td>Essential System Services (including FCAS)</td><td>NA</td><td>NA</td></tr>
</table>

Network	***Avoided/deferred transmission augmentation***	Only applicable where generation aligns with peak RIT-D or average LRMC approach	Applicable to all investments RIT-T or average LRMC approach
	Avoided/deferred distribution augmentation	Only applicable where generation aligns with peak RIT-D or average LRMC approach	Applicable to all investments RIT-D or average LRMC approach
	Distribution network reliability	NA	Only applicable where additional batteries have been enabled Approach based on batteries supplying customers during outages
	Avoided replacement / asset derating	Only applicable where generation aligns with peak RIT-D or average LRMC approach (if applicable)	Applicable to all investments RIT-D or average LRMC approach
	Avoided transmission losses	Applicable to all investments but already included in wholesale market calculations	
	Avoided distribution losses	Applicable to all investments but already included in wholesale market calculations	
Environment	***Avoided greenhouse gas emissions***	Only applicable where there is a jurisdictional requirement to consider. Otherwise already included in wholesale market benefits Emission intensity factor applied	
Customer	***Changes in DER investment***	Applicable to all investments which result in a change in customer investment in DER Calculated based on change in investment over total customer base	

6 Conclusions and Recommendations

6.1 Conclusions

The Study has found that there is a compelling need for the AER to provide additional guidance for network businesses to value the benefits of investments which enable DER integration.

Currently, network businesses are adopting inconsistent approaches to the identification, scoping and valuation of benefit streams arising from investment in DER integration. Consumer advocates and other industry stakeholders do not have sufficient knowledge and/or transparency to review and comment on the approaches adopted.

To date, only SA Power Networks, Energy Queensland and the Victorian NSPs have attempted to undertake detailed quantified DER integration business case as part of their regulatory proposals. It is likely that all NSPs will feature DER integration expenditure as a new category in their upcoming regulatory proposals as a result of increasing customer pressure or potentially as a result of Rule changes currently being considered by the AEMC.

While the RIT-D guidelines do provide comprehensive guidance as to how cost benefit assessment should be generally undertaken, further guidance is needed as it explicitly relates to calculating DER benefits (especially in the wholesale market) and the development of counterfactuals to DER integration investment.

6.2 Recommendations for AER

6.2.1 Form of Guidance

The AER has already produced a number of guidance and practice notes to guide network businesses on how they might prepare business cases related to specific types of expenditure. It is recommended that the AER prepare a guidance note or practice guide setting out a principle-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 so as 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.

6.2.2 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 (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).

6.2.3 Guidance on calculating hosting capacity

The AER should consider developing guidance for networks to follow in assessing the hosting capacity of their networks. DER integration business cases depend in large part on hosting capacity, the amount of DER a network views its current system can handle, and what it believes it will be able to handle 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 they should calculate the results of that analysis to stakeholders.

6.3 Considerations for other bodies

6.3.1 AEMC

AEMC could consider whether and how clarity may be provided as to how networks should apply equity considerations to the allocation of hosting capacity, potentially via its current consultation on DER Access, Pricing and Incentive Arrangements Rule Change process aimed at updating regulatory arrangements for DER.[40] Consideration of equity implications may also require direction by State and Territory Governments.

There are currently a variety of existing approaches being taken to setting export limits via connection arrangements, whereby networks are attempting to manage power quality impacts and customer expectations with respect to DER exports. By virtue of this, whether explicitly or not, these approaches have equity implications between existing DER customers and future DER customers.

While this issue is much broader than our Study, it has implications for the way in which network businesses consider the base case in their DER integration business cases.

6.3.2 State and Territory Governments

Where no other formal policy mechanism to value carbon emission reductions exists, State and Territory governments could consider requiring network businesses, who operate in their jurisdictions, to value the potential carbon emission reduction benefit of an increase in DER hosting capacity in their cost benefit assessments for DER integration and nominate the value to be adopted (in terms of $ per tonne of carbon equivalent avoided).

Where a State or Territory government elects to do this, the methodology set out in this report provides a mechanism for networks to calculate value of avoided carbon emissions.

[40] AEMC, Distributed energy resources integration - updating regulatory arrangements, Consultation paper, 30 July 2020

Appendix A Stakeholder engagement

A.1 Stakeholder organisations consulted

Table 10 – Stakeholder organisations consulted

Interview Group	Organisation
Group 1 – AER Consumer Challenge Panel (CCP)	Robyn Robinson Bev Hughson David Prins Mike Swanston
Group 2 – Consumer Groups	St. Vincent de Paul Society ACT Council of Social Services (ACTCOSS) Renew Brotherhood of St. Laurence Total Environment Centre Queensland Council of Social Service (QCOSS) Uniting Care Australia Country Women's Association of Australia
Group 3 – Victorian DNSPs	AusNet Services Jemena CitiPower/Powercor/United Energy
Group 4 – Market Bodies	AEMC AEMO
Group 5 – New Energy	Clean Energy Council Tesla Sonnen Zepben
Group 6 – NSW/ACT DNSPs	Essential Energy Ausgrid Evoenergy
Group 7 – Other DNSPs	Energy Queensland TasNetworks Power Water Corporation
Individual	Australian Energy Council (AEC)
Individual	Energy Consumers Australia
Individual	SA Power Networks
Individual	Energy Networks Association
Individual	Victorian Government Department of Environment, Land, Water and Planning

A.2 Stakeholder Engagement Themes

The key themes that emerged from the stakeholder engagement are summarised below.

A.2.1 Inconsistency/lack of transparency in DNSP approaches to valuing DER benefits

Customer advocates reported that there is an inconsistency in the way in which DNSPs have valued DER within their regulatory proposals. DNSPs, particularly those that have included DER integration in their expenditure programs, are also aware of this inconsistency. The difference between the Victorian DNSPs' approach of adopting feed-in tariffs as a proxy for benefits versus SA Power Networks' approach of market modelling was highlighted as a key difference in current approaches.

A.2.2 Diversity in DNSP DER integration activities

DNSP stakeholders report to be at various stages in terms of considering and proposing DER integration investments. DNSPs without significant smart meter data have lower levels of visibility of their low voltage networks and are therefore more likely to propose investments to increase visibility, prior to other more capital-intensive investments. DNSPs with higher levels of visibility due to existing smart meter infrastructure are more likely to propose investments for control of solar PV systems (via flexible connection arrangements) and potentially invest in expanding capacity to overcome voltage and capacity constraints where it is economic to do so.

One exception to this was SA Power Networks. SA Power Networks does not have access to large volumes of smart meter data. However, high penetration levels of solar PV and emerging voltage constraints meant that SA Power Networks undertook significant modelling of its network to inform its DER integration investment in its 2019 regulatory proposal.

DNSP stakeholders commented that any value of DER benefits methodology should be applicable to investments which increase visibility, control AND capacity.

A.2.3 Need for DNSPs to prepare a DER integration strategy

Customer advocates suggested that each DNSP should present a coherent and coordinated approach to DER integration across its expenditure plans, tariff strategy and demand management strategy in future regulatory proposals.

They 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 around 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.

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

A.2.4 Form of guidance

Most stakeholders agreed that guidance will need to be both principles-based (to flexibly account for external changes) and prescriptive-based (to provide greater certainty of the approach for calculating wholesale market benefits).

Most stakeholders further considered that it was unlikely that there will be a 'one size fits all' methodology that is likely to be appropriate for all projects. Consequently, any guidance provided would need to be able to be flexibly applied and able to accommodate both jurisdictional processes and differences in DNSPs' LV visibility and access to data.

Some DNSPs saw value in diversity of approaches, particularly with respect to the quantification of network benefits of DER. Notwithstanding, these same DNSP stakeholders saw value in improving consistency specifically related to the wholesale market benefits of DER.

Some stakeholders suggested that it would be helpful if several approaches were developed, with guidance provided on which methodology and calculation methods should be adopted based on the nature and characteristic of the investment. It was considered that adopting this approach would help avoid duplication of effort and avoid some of the complexities and resource intensiveness required in applying the RIT-D cost benefit process to smaller projects.

A.2.5 Application of market modelling

All DNSPs commented that they do not have internal capability to undertake market modelling and would need to rely on external parties' market models where this was required to validate DER integration expenditure.

One DNSP noted that this was not necessarily an issue (as DNSPs frequently outsource various activities where they lack capability), but that there may be efficiencies in market modelling being undertaken centrally (potentially by AER or AEMO) to provide useful inputs in DNSPs investment proposals and that such an approach could avoid duplication.

A.2.6 Value in a prescriptive approach to VaDER for wholesale market benefits

Most DNSPs considered that 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 echoed 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 a diversity of approaches to ensure that the Method evolves over time as the industry evolves.

A.2.7 Inclusion of intangible consumer benefits

Consumer advocates and some DNSPs 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 assessment framework. One consumer advocate stated that such benefits could be included as "consumer surplus" where they could be shown to be additional to standard economic benefits via a willingness to pay survey.

A.2.8 Value of DER benefits methods should be considered in the context of broader regulatory/market reform

Stakeholders of all types raised a number of issues related to broader market reform outside of the scope of this project. These included:

- Incentive and access regimes: stakeholders raised the prospect of future changes in the regulatory framework which will require or incentivise DNSPs to provide for certain levels of access and wanted to understand how this Study could potentially assist or complement any such change.
- Pricing and network tariffs: stakeholders, and particularly customer advocates, were very concerned about the way in which the value streams identified would be transferred to customers and the potential for equity impacts depending on pricing and network tariff settings.
- Future DER markets: stakeholders also discussed that some of the value streams proposed were subject to the type of market in place at the time and so that any method would need to be flexible to changes in these markets. Stakeholders further raised that, in future, DER markets may actually signal benefits to DNSPs.

A.2.9 Broader issues with the DNSPs DER CBA methodologies (beyond value of DER)

Some consumer advocates expressed doubts as to whether assumptions used in DER integration cost benefit assessments were realistic in relation to meteorological and engineering realities. It appeared that some methodologies assumed maximum PV production every day and did not adequately take into account self-consumption or consider appropriate counterfactual scenarios.

Some stakeholders suggested that it would be helpful if several approaches were developed, with guidance provided on which methodology and calculation methods should be adopted based on the nature and characteristic of the investment. It was considered that adopting this approach would help avoid duplication of effort as well as some of the complexities and resource intensiveness required in applying the RIT-D cost benefit process to smaller projects.

Appendix B Response to stakeholder submissions

The table below sets out our responses to submissions received on the draft consultation report. The table provides a response by key theme or to individual comments as appropriate and further identifies whether/where in the report the comment has been addressed. Some response have also been addressed within a separate Frequently Asked questions document as nominated in the final column of the table.

Table 11 – Response to stakeholder submissions

ID	Theme	Stakeholder	Comment	Response	Where addressed (report/FAQ/No update)
1	Scope of study	Anonymous	Not clear whether report shows that NPV is negative	The report does not include any review of the costs of integrating DER – and is focused only on the benefit or value that newly integrated or better integrated DER provides. The figure that was confusing has been amended in the report. The worked example in the chart (Executive Summary) has been revised. The new worked example considers that the export limit is lifted for both existing DER and new DER. The benefits from existing DER now offset the costs of the increased DER size for new DER. This is considered a more likely outcome than the previous worked example.	Report. Figure 2
2	Inclusion of government subsidies	Webinar attendee	Should you exclude government subsidies to be consistent with RiT-T (where government investment is excluded)	Our methodology proposed that, where additional DER costs are included, then the subsidised component of the DER costs is excluded, consistent with RIT-T. Table 15 in the consultation report stated that DER subsidies were included (meaning that the impact of the subsidy on the DER cost was to be included).	Report. Table 15

ID	Theme	Stakeholder	Comment	Response	Where addressed (report/FAQ/No update)
				Based on this comment, we agree this is confusing and have updated to read "excluded" with a footnote explaining our position for clarity.	
3	Network investment to accommodate DER	Brotherhood of St Laurence (BSL)	Supportive of network investment to accommodate DER where it is necessary and efficient.	Noted.	No update required
4	Report recommendations	SA Power Networks (SAPN)	Considered that the many of the draft report's recommendations appear reasonable.	Noted.	No update required
5	Report recommendations	Essential Energy	Noted its support of the following recommendations: • Requiring the AER prepare a guidance note or practice guide setting out a principle-based approach to preparing business cases for DER integration which identifies the types of DER benefits which may be included, how wholesale market benefits are calculated, as well as setting out a methodology for how businesses investment cases should be reported. • The AER should annually commission, the development of standard input assumptions which may be used as inputs to DER integration cost-benefit assessments, and where possible align these assumptions with other regulatory bodies methodologies, eg AEMO's ISP. • The AER to develop guidance for networks to follow when assessing	Noted.	No update required

ID	Theme	Stakeholder	Comment	Response	Where addressed (report/FAQ/No update)
			the hosting capacity of their networks. • That individual State jurisdictions should investigate methods for the valuing of environmental benefits as a way of further informing network's DER hosting capacity decisions and investments. It also noted that investigations should also consider a value of resilience component and the value that communities place on this.		
6	Report recommendations	Renew	Strongly supports the recommendations in chapter 6 of the consultation paper.	Noted.	No update required
7	Report recommendations	Frontier Economics for AusNet	Considered that the report should include a recommendation for the AER to establish guidelines outlining when forecasting changes in DER is required and provide guidance on how it should be undertaken. Advocated that a recommendation be included that establishes a rule of thumb for accounting for the value of intangible benefits.	For the most part, we think it is unlikely that networks will – or should – change their DER adoption forecasts between scenarios, given that we suspect most network expenditure will focus on ICT investments and operational changes rather than significant expansion of network infrastructure. 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. One instance in which there might be a change in DER adoption forecasts is a case in which the network invests in new network infrastructure (e.g. larger transformers) that would enable networks to raise their default connection limits. We think this example will be relatively uncommon and unlikely.	Report. Minor reframing and de-emphasis on additional DER costs in section 4.2.1

ID	Theme	Stakeholder	Comment	Response	Where addressed (report/FAQ/No update)
8	Report approach	BSL	Broadly supportive of the draft report, which it considered sufficiently granular to provide a useful indication of the value of different proposed investments.	Noted.	No update required
9	Report approach	Jemena	Broadly supportive of distinguishing between shorthand and longhand methodologies for the calculation of market benefits.	Noted.	No update required
10	Report approach	SAPN	Supported measures that can assist DNSPs and stakeholders in streamlining the economic analysis to support expenditure proposals.	Noted.	No update required
11	Report approach	Clean Energy Council (CEC)	Strongly supported the proposal to develop guidance for networks to follow in assessing the hosting capacity of their networks. It considered that AER guidance on how networks should analyse hosting capacity and how to communicate those findings to stakeholders would be of great assistance to investors, planners and regulators.	Noted.	No update required
12	Report approach	Renew	Agreed that the issues cited in the consultation paper are problematic in current approaches to valuing DER used by DNSPs and other bodies, and that a more robust and evidence-based methodology is required.	Noted.	No update required

ID	Theme	Stakeholder	Comment	Response	Where addressed (report/FAQ/No update)
13	Network benefits	Renew	Noted that the issues of variability of DER network benefits need to be recognised and managed within the methodology used to value DER, especially the spatial and temporal variability – the location of DER and the timing of DER injections into networks are both critical factors in whether DER can have a positive or negative value.	The methodology sets out in detail the need to identify the temporal variability of DER services enabled. We agree that the spatial variability is also critical to quantification of network benefits and have clarified that this should be considered.	Report. Clarified in section 5.3.1 that consideration should be given to spatial variation in the volume of DER services where network benefits are considered
14	Methodology application	BSL	Sought further clarification on what types of investment the value of DER is intended to apply to. It also sought clarification on whether the methodology is intended to provide networks with a consistent method to value non-network solutions to DER capacity augmentation (e.g. deployment of distribution-scale batteries to jointly address export driven voltage constraints and to reduce peak loads) and whether this type of non-network solution be able to consider the same value streams?	The methodology applies to any network investment which enables additional energy or capacity from DER. This includes network investment in non-network options (typically via opex payments). While not explicitly considered in the report, the methodology could also apply to the quantification of market benefits where a network considers investing in DER to meet any network need.	No update required
15	Methodology application	CEC	Costs of DER integration must be attributed in a fair and reasonable manner. Investments to improve visibility of low voltage networks should not be attributed entirely to DER integration when there are benefits which extend beyond DER integration.	We agree that DER benefits may only form part of the business case for network investment. This is particularly true for ICT investments which may not only improve DER hosting capacity but also give rise to other operating efficiencies unrelated to DER. The methodology in our report sets out how to value DER benefits only, which may then be stacked with other benefit types where appropriate.	No update required
16	Methodology application	Frontier Economics for AusNet	Considered the methodology approach of comparing total electricity system costs from increasing hosting capacity with the total electricity system costs of not doing so to be reasonable in broad terms. However, considered that issues are likely to arise with the implication of this methodology.	Noted.	No update required

ID	Theme	Stakeholder	Comment	Response	Where addressed (report/FAQ/No update)
17	Methodology application	AusNet	Expressed concerned regarding the potential application of the methodology to its regulatory distribution determination for 2022-26 given that the methodology is still being developed and has not had the same level of stakeholder consultation as the Victorian Feed in Tariff (FiT) which has been used for calculating the benefit of DER. It noted that the FiT is widely accepted by stakeholders and was developed over a 2.5year consultation process.	The Victorian FiT values a different service than we are valuing, which is solar full-time production. Solar full-time production is different to the profile of additional solar released when hosting capacity is expanded – see example profiles in report. The Victorian FiT process is in fact still evolving with the methodology used in the last determination significantly different to the previous year in terms of approach to weighting wholesale prices.	Report. Section E.6 and Footnote 68
18	Changes in DER over time	AusNet	Considered that the only reasonable approach for forecasting how the value of DER will change over time is the longhand market modelling approach. However, it noted that there might be value in establishing a framework for forecasting changes in DER that recognises that many of the drivers of DER investment are not related to the capability of the network.	Shorthand methods are less costly and have greater transparency and repeatability. Longhand modelling is recommended for large, high impact projects and where adopted it is important to improve transparency by publishing significant details of assumptions and outputs.	Report updated to include outputs required from longhand approach at the end of Section D.3 - Selection
19	Changes in DER over time	Frontier Economics for AusNet	Identified several issues with seeking to quantify the costs of changes in DER investment including: • Difficulty in attributing a share of costs and benefits for DER services,	See 7 above.	

ID	Theme	Stakeholder	Comment	Response	Where addressed (report/FAQ/No update)
			given that DER investment decisions are driven by a range of factors[41] • The range and complexity of DER investment is likely to exacerbate difficulty in attributing an appropriate share of cost and benefits to the provision of DER services. Alternatively, it suggested that all costs and benefits of DER are included, including intangible benefits.		
20	Changes in DER over time		The statement that "rooftop solar costs are subsidised by Commonwealth policies in 2030 in all states"5 obscures the nuance that STCs are being gradually phased out and that, for example, the subsidy applicable in 2030 is very small. The additional Victorian subsidy will also scale down between now and 2030. The jump in cost shown on the chart for 2031 appears to show a sudden end that seems too abrupt to account for the tapering of these subsidies	Clarified in the report that we taper Commonwealth subsidies because there is a known formula for this, but not Victorian subsidies because there is no firm policy in that regard. Users may impose an estimated deceleration rate if data is available.	Report. Section E.2 Footnote 60

41 See findings from, Energy Consumers Australia, 'Consumer Sentiment and Behaviours,' 31 July 2019.

ID	Theme	Stakeholder	Comment	Response	Where addressed (report/FAQ/No update)
21		AusNet	Noted that the Victorian FiT is calculated in essentially the same way as the shorthand Running Cost Method. It did not consider that there was compelling evidence to suggest that the FiT trended lower over time and cautioned against assuming that half-hourly prices at times of solar PV generation will fall over time.	The Victorian FiT is backward looking in its methodology in the sense that it sets price well before the year to which it applies. As a result, current FiT prices are no indicator of current price trends but rather in this case some historically high prices. We already show that negative prices are increasing in the report using more up to date data and are confident the next FiT calculation will be lower than previous estimates	No update required
22		Frontier Economics for AusNet	Noted that the key difference between the Victorian FiT and Running Cost Method is that the VaDER Running Cost Method recommends applying an annual index to represent the change in total cost of large-scale solar PV. It considered this approach to be questionable, as there is no reason to think that half-hourly wholesale electricity costs will move in line with movements in the total cost of large-scale solar PV.	Our strong recommendation is that we would like proponents to use published projected half hourly prices (perhaps with the AER facilitating those projections). However, since we cannot guarantee that will be published and we have no access to such forecasts at this time, we use a second-best approach which is the trend in large-scale solar costs. Since the ISP shows nearly all regions building more large-scale solar and as long as the market is well-functioning, prices during the day time (on-average over time) will have to reflect large-scale solar costs in order to allow that investment to occur.	Report. Clarification added to Section 5.3.3 footnotes 37 and 38
23	Relationship between network investment and DER investment costs	AusNet	Considered that network investments do not directly result in increased DER costs for the following reasons: • Customer decisions to invest is DER is driven by a range of factors, consequently attributing the cost of these to DER services is challenging • Customers that invest in DER are unlikely to consider network conditions in making investment decisions	See 7 above.	

ID	Theme	Stakeholder	Comment	Response	Where addressed (report/FAQ/No update)
			• Estimating the costs of investment that provide a range of services beyond supplying electricity to the grid and attributing those costs to DER services is impractical.		
24	Relationship between network investment and DER investment costs	Frontier Economics for AusNet	Considered that a more appropriate approach is to presume that network investments do not directly increase costs of DER investment and to instead define clear criteria to provide guidance on circumstances where this presumption does not apply and suggested that in these cases it would be appropriate to: • Provide a framework for forecasting a change in DER that recognises that many DER investment drivers are not related to the capability of the network • Establish a rule of thumb to account for the value of intangible benefits of DER to ensure that relevant costs and benefits are appropriately accounted for.	See 7 above.	

ID	Theme	Stakeholder	Comment	Response	Where addressed (report/FAQ/No update)
25	Relationship between network investment and DER investment costs	Renew	The treatment of change in customer DER investment may need to be nuanced. If hosting capacity is increased, customers may choose to invest in larger generation systems because they can realise more private benefit from greater exports. If hosting capacity is not increased or is reduced, this may encourage customers to invest in smaller systems with lower shared benefit; or it may encourage investment in large generation systems with batteries, which is more likely to reduce private benefit (compared to the same system without batteries)	These points are already covered in discussions around BAU vs investment case and scope of benefits included.	No update required
26	Dynamic exports/DER orchestration	BSL	Implications for dynamic export constraints should be considered directly in the methodology. BSL noted that dynamic control of DER exports is currently being developed by several DNSPs with high PV penetration, which implies an important difference for the base case. Where dynamic constraint functionality is implemented, the volume of additional export enabled by augmenting low voltage capacity is smaller than for the 'inverter trip' base case, so that the value of additional investment is lower.	While dynamic export constraints cannot be included due to the lack of readily available data on what such a profile would look like, we have provided more text about how the methods would apply to this case. The running cost method would most likely apply.	Report. Section 5.3.4, footnote 39 FAQ
27	Dynamic exports/DER orchestration	SwitchDin	Strongly recommended that dynamic capacity exports, DER orchestration, and variable network charges be explicitly mentioned within the methodology, with worked examples provided, to ensure that the methodology allows for both current, emerging, and future technologies for maximising DER value and hosting. It considered that without consideration of	See 26 above.	

ID	Theme	Stakeholder	Comment	Response	Where addressed (report/FAQ/No update)
			these issues, the approach may lead to suboptimal investments.		
28	Flexible energy and flexible capacity value streams	Frontier Economics for AusNet	Did not consider that it was useful to distinguish between flexible energy and flexible capacity provided by DER and instead considered that this distinction may lead to confusion. It noted several value streams that flexible energy can provide that were not included in the value streams noted in Table 4 of the Draft Report. These include: • Flexible energy provided by active DER systems can result in avoided generation capacity for the same reasons that variable energy provides these benefits • Flexible energy provided by active DER systems can result in avoided transmission and distribution augmentation for the same reasons that variable energy provides these benefits • It is not clear why variable energy can provide value through avoided replacement or asset de-rating, but flexible energy cannot provide that value It also requested further clarification on the distinction between active DER that is providing flexible capacity (which means that it can provide essential system services) and	We agree with the first two dot points and these have been added to Table 4. In regard to dot point three, in theory they could all reduce load at peak demand. How successful this is would depend on when that occurs. We agree a passive DER technology can only provide variable energy services. An active DER technology can potentially provide a combination of flexible energy and capacity services. In this sense, the distinction between flexible energy and flexible capacity is not essential to understanding the conceptual value of DER. However, the distinction becomes important in the methodologies for calculating value. In simplified methods it is often practical to focus on the single most valuable type of service. The distinction also assists with identifying what costs are avoided. For example, the running costs method cannot be used to evaluate capacity.	Report. Section 4.1, Table 4 adjusted and flowed through to Table 9. Footnote 33 added for clarification

ID	Theme	Stakeholder	Comment	Response	Where addressed (report/FAQ/No update)
			active DER that is providing flexible energy but is assumed not to be able to provide essential system services. It considered that a simpler distinction between passive DER systems and active DER systems would be more preferable, as it would avoid potentially valuing only a subset of the benefit types attributed to flexible energy and capacity services. If adopted, active DER systems would provide all of the value streams identified in Table 4, while passive DER systems would provide all the value streams currently identified under variable energy.		
29	Flexible energy and flexible capacity value streams	Renew	Renew commends the distinction between the three types of services – variable energy, flexible energy, and capacity – and the consideration of interaction between the three services – such as the example given that increased support for variable energy may reduce flexible energy and capacity. We note that the various approaches DNSPs might use to increase hosting capacity may also interact with each other – some whole-of-system modelling may be needed for DER enablement planning as well as for DER valuation.	Noted.	No update required
30	Flexible energy and flexible capacity value streams		The 5 kW per connection increase in hosting capacity modelled in the worked example will not just be used for the VPP offering capacity services to the wholesale market; it will also be used to just export extra surplus generation at other times, often providing additional variable and flexible energy	We agree. Clarifications have been included to make it clearer that stacking benefits is supported.	Report. Section 5.3.1

ID	Theme	Stakeholder	Comment	Response	Where addressed (report/FAQ/No update)
			benefits (the latter due to any batteries installed). This is why considering the different DER services together is important, and suggests that the relative frequency and duration of opportunities for different services is as significant a factor as the relative value.		
31	Intangible benefits	AusNet	Considered that there is merit in including a 'rule of thumb' for accounting for the value of intangible benefits of DER to ensure that relevant costs and benefits are accounted for.	We recognise that customers receive "intangible" or simply difficult to quantify benefits that have not been accounted for in our methodology. The main reason for excluding them is that they are indeed difficult to quantify, and the simplest and cleanest approach is not to include them in the methodology. We also assume that these intangible benefits are relatively small. However, we recognise that customer willingness to pay surveys may have an important role to play in the broader issue of network expenditure for DER integration. In the DER integration context, customers' measured willingness to pay ultimately would have to be compared to the cost of the DER integration – either the net cost (minus any benefits) or the cost allocated to specific customers. In other words, while customer willingness to pay surveys may be useful and informative in the overall development of a DER integration expenditure proposal, it would not reduce or constrain the need to conduct a cost-benefit analysis using the VaDER methodology. Indeed, first developing a cost-benefit analysis and then using insight from it into the actual price likely offered to customers may yield a more informative survey and more trustworthy response.	No update required FAQ

ID	Theme	Stakeholder	Comment	Response	Where addressed (report/FAQ/No update)
32	Intangible benefits	Frontier Economics for AusNet	Disagreed with the view that intangible benefits are likely to be true for early adopter markets (such as batteries) but less likely for established markets (such as rooftop solar PV). It noted that this finding was inconsistent with survey results conducted by Energy Consumers Australia on consumer attitudes and purchase intents for solar panels and battery systems.	We assume that the value of intangible benefits is relatively small. While ECA survey results suggest that customers purchase solar panels and batteries for many reasons in addition to saving money, the surveys also reveal that saving money is the primary motivation. Electric vehicles are another DER that provides a variety of environmental and other intangible benefits to their owners, however their sales are still quite limited in Australia today. We attribute this to the lack of economic motivation. As EV prices drop, we anticipate adoption to grow rapidly. Although we recognise that there are early adopters in technology, most literature suggests they are a small fraction and that most customers are influenced primarily by the economics of the situation.	No update required FAQ
33	Exclusion of electricity bill management benefits	BSL	Did not agree that 'electricity bill management' should excluded as a value stream in the methodology. It considered that avoided retail margin costs have not been included in the methodology and would not be result in double counting of benefits.	We consider that any avoided bill benefits are as a result of transfers or other benefits identified and set this out in Section 4.3 of the report. We further consider avoided retail margin costs to be a transfer. While individual customers as a result of greater DER export may avoid retail margin costs on their bill, it is our view that these costs are, for the most part, not avoided entirely. Retail margin costs tend to be on a per customer basis rather than volume basis (such that they are not avoided where volume of grid consumption decreases, only where the number of customers decreases).	No update required
34	Exclusion of electricity bill management benefits	CEC	Considered that benefits of DER for reducing electricity bills should be acknowledged, with care taken to avoid double counting.	We agree that the benefit can be quantified as market benefits and/or benefits to various parties including customers (as well as retailers, aggregators, etc).	No update required

ID	Theme	Stakeholder	Comment	Response	Where addressed (report/FAQ/No update)
			CEC understood that this benefit can be quantified as avoided generation short-run marginal costs (SRMC) and can also be quantified in the form of reduced costs to customers. The CEC urged CSIRO and CutlerMerz to report the value of both benefits, even if only one of the values is used for the purpose of calculations to avoid unhelpful framing of DER benefits and potential for the methodology to be misinterpreted. It considered that DER benefits should be framed from the perspective of the consumer, rather than the perspective of other generators that will compete with DER.	We agree that it is important for customers to understand how these benefits transfer to various parties and, in particular, how they flow to reduced electricity bills. However, transfer of benefits was not part of the scope of this project and will be network and customer specific (depending on the form of network, retail tariff, customer load profile and DER investment).	
35	Avoided greenhouse gas emissions	BSL	Noted that it supports the inclusion of the cost of carbon in determining DER benefits and noted that this position was also supported by networks. It noted that the reduction in greenhouse gas emissions is a key motivator for households that install DER, and that it is appropriate that the value consumers place on emissions reductions be taken into account in distribution planning and AER decisions.[42]	Noted.	FAQ
36	Avoided greenhouse gas emissions	CEC	Considered that it would be preferable if there was an agreed value for avoided greenhouse gas emissions that could be		

[42] Best, R., Burke, PJ and Nishitateno, S. (2019), 'Understanding the determinants of rooftop solar installations: evidence from household surveys in Australia,' CCEP Working Paper 1902, Crawford School of Public Policy, The Australian National University.

ID	Theme	Stakeholder	Comment	Response	Where addressed (report/FAQ/No update)
			applied nationally rather than applying jurisdictional based values, which are likely to vary by State and Territory. Suggested that it would be helpful to clarify whether it will be necessary for the jurisdictional policy to include an explicit carbon price or whether the AER intends to derive the effective carbon price based on policies designed for other purposes (e.g. RET). It noted that it may be simpler and more transparent to allow jurisdictions to nominate a shadow price to be used for the purposes of the AER's assessment on DNSP expenditure on DER integration.		
37	Avoided air pollution benefits		The Victorian FiT does not include a value for reduced air pollution, this was ruled out by the ESC for a number of reasons including difficulty quantifying the benefit, and the pollution reduction from Victorian distributed generation largely occurring in other states.7	Noted.	Report (various)
38	Customer willingness to pay	Ausgrid	Disagreed with the report's exclusion of customers' willingness to pay from VADER methodology and sought further clarity on why the methodology has deviated from including customer willingness to pay. It considered that the regulatory framework allows networks to make investments in hosting capacity to the level of customer value and willingness to pay which is aligned to how reliability levels are currently set. It considered that the methodology should include an option for including customers' willingness to pay and noted that several DNSPs as a result of extensive engagement have included programs to improve hosting	Even though we have excluded them from this methodology, customer willingness to pay surveys may have an important role to play in the broader issue of network expenditure for DER integration. Willingness to pay surveys may be particularly useful if costs of DER integration outweigh benefits, and/or if networks intend to allocate costs of DER integration through export tariffs or other mechanisms that fall exclusively or disproportionately on DER customers. In the DER integration context, customers' measured willingness to pay ultimately would have to be compared to the cost of the DER integration – either the net cost (minus any benefits) or the cost allocated to specific customers. In other words,	Report. Added content to Section 2.4 to explain potential role of willingness to pay in broader context of DER integration. FAQ

ID	Theme	Stakeholder	Comment	Response	Where addressed (report/FAQ/No update)
			capacity based on strong customer feedback.[43]	while customer willingness to pay surveys may be useful and informative in the overall development of a DER integration expenditure proposal, it would not reduce or constrain the need to conduct a cost-benefit analysis using the VaDER methodology. Indeed, first developing a cost-benefit analysis and then using insight from it into the actual price likely offered to customers may yield a more informative survey and more trustworthy response.	
39	Customer willingness to pay	SAPN	Considered that the central role of customer willingness to pay should be better recognised in this review. It considered that network expenditure will align better with economic efficiency when it is driven customers desires and willingness to pay for network services. It noted that value streams identified in the draft report were guided by the AER's RIT, yet it appears to overlook that changes in consumer and producer surplus include a quantified consideration of customer preferences. SAPN noted that the most direct way of doing this was to set price and observe customer demand, noting that export charges would help to reveal a customer's willingness to pay over time. It considered that the methodology should consider a VCR equivalent for export services.	As some customers place additional value on DER that is not captured by the proposed method, this additional "intangible" value could be accounted for through a willingness to pay survey. As noted elsewhere, our methodology does not include the use of customer willingness to pay as a methodology for determining the value of DER integration. However, we recognise that customer willingness to pay surveys may have an important role to play in the broader issue of network expenditure for DER integration. Indeed, we see willingness to pay surveys as potentially complimentary to the VaDER methodology recommended, albeit more focused on cost recovery and cost allocation determinations, which are outside the scope of our review.	No update required FAQ

[43] See, for example, Powercor, *Regulatory Proposal 2012-26*, p. 74 and Jemena, *Future Grid Investment Proposal,* Attachment 05-04 to 2021-26 Electricity Distribution, p. 9.

ID	Theme	Stakeholder	Comment	Response	Where addressed (report/FAQ/No update)
			Without a VCR equivalent for exports it strongly considered that VADER should be an input into ex-ante expenditure assessment and not the sole determinant, given the potential for mismatch between customer willingness to pay and VADER value. Networks should place greater emphasis on what customers actually want not less. Networks business cases to the AER should include analysis on the views of its customers willingness to support a higher (or lower) level of expenditure than suggested by the VADER.		
40	Customer willingness to pay	CEC	Noted that customer preferences should not be overlooked and considered to do so would be contrary to the 'New Reg' approach. The CEC was surprised that given the AER's stated preference for considering what customers want, that the methodology does not consider customer preferences and willingness to pay		See report sections 2.4 on broader context of DER Integration and 4.2.1 on intangible benefits.
41	Customer willingness to pay	SAPN	Noted that it is the payment streams that retailers and VPPs who deal directly with DER products and services that incentivise customers to want to export. The payment streams that customers earn by investing in sufficient DER to export are incentives that are independent of the extent of available network hosting capacity.	Agreed and noted	No update required
42	Customer willingness to pay	Anonymous	Why don't we use a VCR Method?	There are several reasons why we did not recommend using an approach similar to VCR for VaDER. First, reliability is an important metric that has value for all network customers. DER, which may provide value to all customers, is likely to be	No updated required FAQ – dedicated question

ID	Theme	Stakeholder	Comment	Response	Where addressed (report/FAQ/No update)
				more meaningful to customers that own or host it. Non-DER customers are unlikely to find significant value in DER on the network, and accordingly, another approach is likely most appropriate. Furthermore, reliability is a key component of the national electricity objective and is largely considered a given aspect of modern electricity systems. While there are available substitutes (e.g. diesel generators; solar and storage systems) to "reliability", understood as the ability of network supply to provide a customer with a given amount of energy at any time of day throughout the year, they are not cost effective. Furthermore, these alternatives are not seriously considered by most customers today. Accordingly, survey data that estimates the value customers place on reliability is, arguably, the most appropriate and reasonable method to estimate the value of reliability.	
43	Customer willingness to pay	Renew	If the DER Access and Pricing reform supports allowing networks to levy additional charges on DER customers for extending hosting capacity beyond the amount that provides a net shared benefit, then valuation approaches such as these may be useful in assessing such additional expenditure and any proposed charges related to it.		
44	Treatment of government subsidies /policies	CEC	Government subsidies for DER should be treated as external funding. This would be consistent with the approach used by the AER in its consideration of the RIT-T.	See 2 above	Report: Table 5
45	Treatment of government subsidies /policies	AusNet	Government policies can add to the expectation that DER is beneficial and save customers money. These policies tend not to consider network capacity.		

ID	Theme	Stakeholder	Comment	Response	Where addressed (report/FAQ/No update)
46	Comparison of rooftop solar capacity vs new large-scale solar capacity	BSL	Considered that there were important considerations not captured by the methodology due to treating domestic PV owners and generation businesses the same way. One benefit overlooked from adopting this approach is avoidance of retail charges.	Changes in the collection of retail costs is a distribution of benefits issue which is out of scope.	No update required
47	Comparison of rooftop solar capacity vs new large-scale solar capacity	BSL	Noted that the report did not explicitly mention the additional transmission costs associated with building new large-scale solar generation, or solar batteries, which it considers to be a significant and real value stream for DER. It considered that if it is not practical to capture all costs associated with building new generation capacity a more representative method might adjust the system boundaries so that generation investment is not considered.	If the change in DER is large enough to impact transmission investment it will likely trigger the need for electricity system modelling which can evaluate changes in transmission.	No update required
48	Comparison of rooftop solar capacity vs new large-scale solar capacity	SAPN	Noted that investment drivers from customers' decisions to invest in/purchase DER differ to large grid-connected generators like solar farms. In most cases customers invest in DER to self-consume and lower their electricity bills, whereas large-scale grid connected generators investment is more linked to the economic value of exported energy.	It is important to remember that both types of investors expect to be paid for the services they provide to the system despite whatever else might drive the investment. However, it is important to consider the issue of intangible benefits which we address more fully in other comments.	No update required
49	Comparison of rooftop solar capacity vs new large-scale solar capacity	Renew	The statement "Given the relative costs of the two competing technologies there is no generation sector benefit to be found from inducing investment in solar-battery systems with	Given electricity demand is strongly inelastic, it is close to a zero-sum game with respect to who provides that energy at those relevant times of day. Electricity market modelling can dig deeper into the subtleties of the competitive effects, but it is	No update required

ID	Theme	Stakeholder	Comment	Response	Where addressed (report/FAQ/No update)
			higher export limits. They would only displace lower cost investment in large-scale systems"6 appears to assume a zero-sum approach. But large-scale solar can face transmission limitations; and rooftop solar draws upon a different pool of investor capital. AEMO's Integrated System Plan sees overlapping but distinct roles for both large-scale and rooftop solar, which are not fully interchangeable.	reasonable to assume a crowding out of investment in the long run. Also keep in mind we are not talking about rooftop solar but some amount of additional rooftop solar which may have a different profile to rooftop solar.	
50	System boundaries	Switchdin	Supported the recommendation to use 'total electricity system' as a system boundary, including behind-the-meter assets but considered that clarity was required as to whether this system boundary also extends to controllable loads behind-the-meter. Switchdin considered that all behind-the-meter DER be included.	Yes, our definition extends to all DER assets (including controllable loads) behind the meter. Notwithstanding, it is difficult to identify any network investment which may change the way in which customers invest in behind the meter controllable assets (that is, they are likely to invest in these assets regardless of what the network does) and therefore these DER investment costs are unlikely to feature in a network's business case.	No update required
51	System boundaries	SAPN	Disagreed that customer investment in DER will be materially incentivised by/be elastic to DNSP investing in network hosting capacity.	We agree that, for the most part, network investment in unlikely to impact DER investment by customers. If a network assumes that there is no additional DER investment, then additional DER costs should not need to be considered in the cost benefit assessment. However, in our view, there may be cases where network investment could change the DER investment. It is important that, where networks make this assumption, both the costs and benefits of the additional DER are included.	No update required
52	System boundaries	CEC	Supported the use of an 'all of society' approach to system boundaries in combination with the 'total electricity system'	The AER is unlikely to be able to consider benefits outside of the electricity system. Section 4.2.1 sets	No update required

ID	Theme	Stakeholder	Comment	Response	Where addressed (report/FAQ/No update)
			resource approach so that implications from assumptions are more transparent. It did not support making climate out of scope.	out how the benefits the AER is able to consider have been defined for previous guidance.	
53	System boundaries	Frontier Economics for Ausnet	Noted that in principal the logic of assessing costs and benefits for the total electricity system but noted that in practice that there were likely to be material issues with attempting to appropriately quantify the costs and changes in DER investment (Refer to comments regarding changes in DER investment and intangible benefits).	See 31 and 32 above.	No update required
54	System boundaries	Renew	Using a total electricity system resource test is appropriate in some applications of this methodology but risks justifying shared funding of private benefits when used for assessing DNSP DER enablement proposals. The methodology should be able to define the system boundary flexibly and strategically depending on the investment proposals it is being used for.	The methodology provided does not address how the benefits/costs will be transferred. Rather, it identifies whether there is an overall benefit (in terms of consumer and producer surplus). We acknowledge that the benefits of the network investment will flow to DER and non-DER customers in different ways. We suggest that this issue is better addressed by the consideration of pricing mechanisms (rather than the flexible system boundaries).	No update required
55	System boundaries	Renew	The approach to valuing distribution network reliability is an example of the complexities of extending the system boundary behind the meter. A customer using their private investment in a battery to provide power during an outage yields a private benefit in addition to the public benefit of helping a DNSP meet its reliability obligations.. If a DNSP was to invest in batteries itself as the	The examples provided speak to a slightly different context than ours. The investment in the examples provided is primarily to improve reliability rather than hosting capacity.	No update required

ID	Theme	Stakeholder	Comment	Response	Where addressed (report/FAQ/No update)
			most cost-effective way to provide customers in a fragile network node with the required standard of service, it's a clear shared benefit that should be included in capex and shared as all investment to meet demand and service standards is. But investment that enables some customers, but not others, to privately invest for private and public benefit needs to be assessed in a more nuanced way. What proportion of that investment benefits all customers (through improvements in meeting reliability standards), vs only benefits the customers able to co-invest?	Notwithstanding, if a network invests in a battery for reliability reasons it could also include VaDER benefits as set out in our methodology. If a customer invests in a battery for reliability reasons, there is no network investment and so our methodology need not apply (it is not clear that a network would be able to claim improved reliability here in any case).	
56	System boundaries		Renew strongly supports consideration of environmental benefits where they can be realised, but also recognised that current policy settings limit this within the energy system. This is the strongest rationale for looking at extending the system boundary (at the opposite end to the meter side) outside the energy system to capture other benefits of emissions and particulate pollution reduction that will reduce non-energy costs for households, such as food and health expenditure. We recognise that this is outside the remit of this process.	Noted.	No update required

ID	Theme	Stakeholder	Comment	Response	Where addressed (report/FAQ/No update)
57	Base case/counterfactuals	Switchdin	Suggested that the methodology should be considered against the following: • The BAU case • The BAU case with dynamic export limits and DER orchestration of existing DER assets • Where possible, the proposed change including dynamic export limits and DER orchestration of DER assets to ensure that the maximum value of DER hosting capacity is considered.	This reinforces our existing discussion in the report on the importance of careful design of the business as usual case. See 26 above in regard to dynamic export constraints.	No update required
58	Base case/counterfactuals	Jemena	Noted that the work currently being progressed on DER-related reforms is likely to have implications on the base case for DER integration investment analysis. It considered that the base case should reflect the DER mandated settings and requirements of the distributor at the time via the application of the DNSP's existing connection policy.	We strongly agree that the base case should reflect the DER mandated settings. However, this is not currently clear. We recommend in our report that AEMC considers clarifying the mandated settings for the base case via the current reforms	No update required
59	Base case/counterfactuals	AusNet	Reducing export limits to a low or zero level rather than allowing tripping to occur is an acceptable base case and consistent with RIT-D base case guidance. It also noted that tripping is not a technically acceptable option or credible under the Victorian Electricity Distribution Code (EDC). It considered that a base case involving tripping would require it to accept: • Higher network voltage levels for all customers • Increased in voltage bandwidth, which would increase costs	We agree that tripping is not a credible option, but note that the RiT-D guidelines explicitly recommend the use of a base case which may be "*unrealistic*" so long as it provides a clear reference point for comparing the performance of different credible options Further, the use of static export limits as a base case can be arbitrary (in terms of where the limit is set) and will shift business case in favour of NSP investment the lower the export limit.	Report. Updated Section 2.3 to soften the recommendation that a tripping scenario or static export limits could be used as a base case.

ID	Theme	Stakeholder	Comment	Response	Where addressed (report/FAQ/No update)
			associated with managing low voltage issues • Increased customer complaints	Where a static export limit is used as a base case, it should be made clear as to why that particular limit was set and that it is not arbitrary.	
60	Base case counterfactuals	SAPN	Noted that it was incorrect to consider that reducing static limits to low or zero does not align with the RIT-D business case guidance of implementing 'any other credible option' given that static limits are the business as usual (BAU) means in which DNSPs manage hosting capacity. Further, the current BAU approach for maintaining quality, reliability, and security of supply does not currently entail relying on trip settings in AS4777 and/or Volt-Watt response modes in individual inverters. While outside the scope of the review SAPN made the following observations: • Local over-voltage is not an indicator of all network impacts due to high levels of PV and noted a range of other factors which can influence hosting capacity that are not manifested in local voltage rise. • Reliance on local protection settings is inequitable. Fixed export limits allocate capacity more equitably. • Inverters tripping leads to instability at high PV penetrations as it can lead to significant transient changes in local voltage and load levels when multiple inverters are cycling on the same local network, which can cause negative impacts on upstream grid stability and voltage regulation.	See 58 and 59 above.	See 59 above

ID	Theme	Stakeholder	Comment	Response	Where addressed (report/FAQ/No update)
			• Compliance with connection standards is low. • Battery inverters tripping may exacerbate quality of supply issues.		
61	Use of shorthand methods	CEC	Supported the use of the proposed shorthand method but suggested that the AER undertake market modelling to demonstrate whether there are any likely differences between results undertaken using the shorthand method vs electricity market modelling.	There will undoubtedly be differences in estimated values. The question is how material and whether they are biased in any particular direction. This suggestion is out of scope for our study but could be taken on board by the AER.	No update required

ID	Theme	Stakeholder	Comment	Response	Where addressed (report/FAQ/No update)
				Networks may also discover the differences over time if they use the shorthand methods as a screening tool for modelling studies.	
62	Use of shorthand methods	Frontier Economics for Ausnet	Considered that the criteria for when to use the longhand or shorthand methods should be clarified to address: • Whether investment needs to meet each of these criteria for the shorthand method to be appropriate, or whether the investment only needs to meet one of the criteria • Further guidance on what qualifies an investment that is relatively small, it considered that a dollar value threshold would be helpful • How does a network assess whether the investment is likely to give rise to a small amount of DER capacity relative to the energy market that it will impact? • What energy market should be used for this comparison – the NEM as a whole, the network's region within the NEM, the network itself? How should networks forecast likely increases in DER capacity?	The report now clarifies that both key criteria need to be met. The existing text also says that the threshold for scale is around 50MW, which is consistent with multiple millions in benefits and this aligns with the existing guidance around a $6M threshold. The report now clarifies that the focus of impact is at state level. The report has removed the project life criteria (this was too tight a constraint on reflection given most assets will be long lived). The risk of longer-lived projects is countered by the methods and the recommendation of centrally provided modelling of some inputs. DER forecasting approaches are out of scope for this project.	Report Section 5.3.2 Clarified that both key criteria need to be met Clarified scale of impact relates to state Section D.3 Removed project life criteria (was too tight on reflection)
63	Change in value over time	Frontier Economics for Ausnet	Considered that assuming that the value of DER under the Running Cost Method remains constant over time was a more preferable approach to changes in forecast value, as the only reasonable approach for	See 22 above.	See 22

ID	Theme	Stakeholder	Comment	Response	Where addressed (report/FAQ/No update)
			forecasting how the value of DER will change over time is the longhand market modelling approach.		
64	Change in value over time	Renew	"For the trend in prices that would be received by rooftop solar PV, an index of the change in the total costs of large-scale solar should be used."4 It's not clear why the costs of large-scale solar is appropriate, rather than the marginal cost irrespective of generation type for the applicable time of day.	As explained in the report, if you displace a similar technology, then you cannot also claim to be avoiding marginal costs because available generation in the investment case has not changed relative to BAU.	No update required
65	Assumptions	CEC	Sought clarification regarding which scenario from AEMO's ISP are to be selected (e.g. the central or step change scenarios) and which development paths are to be selected. It noted that it might be preferable to use both the central and step change scenarios (for the purposes of sensitivity analysis) rather than selecting a single scenario.	We advise in the report using the RIT-D approaches for scenario selection, including the advice that multiple probability weighted scenarios are selected	No update required
66	Assumptions	SAPN	Considered that the final report would benefit from more detailed explanation on the assumptions and approaches used to arrive at the VADER testing results, and whether a new interconnector to South Australia had been factored into the analysis. Request an explanation for why South Australia VADER results differ greatly from the VADER for other NEM jurisdictions, and what assumptions have been used in respect to volumes of tripped solar and the value of that solar.	Shorthand methods would not include interconnector modelling given they are simplified by design. The discussion length and detail available in the report is already considered high.	No update required

ID	Theme	Stakeholder	Comment	Response	Where addressed (report/FAQ/No update)
67	Use of projections	CEC	Noted that some differences exist between the CSIRO projections cited in the draft report and AEMO projections. Specifically, it noted that CSIRO's forecast of over 40% of customers in Australia will use on-site DER by 2027 providing 29GW of solar PV and 34 GWh of behind the meter batteries, which is a higher estimate of PV generation and a lower estimate of battery capacity compared with AEMO's step change least cost scenario (DP4), even if WA is included.	Agreed that it is confusing having two sets of forecasts in the report. ENTR forecasts removed and additional detail on AEMO ISP projections added.	Report Section 1 Introduction
68	Comments on Total Cost Method	Frontier Economics for Ausnet	Considered that the Total Cost Method would be problematic to implement as the criteria for using it are vague. For example: • What does it mean for DER to be available over an extended period? • How do networks judge whether additional DER is need in that generation region and what lead times are necessary for additional capacity or electricity to emerge? • How do networks judge that an annual energy profile is a reasonable substitute for the relevant standard solution? It did not consider that the annual capacity factor was a useful test of the relative value of different sources of generation and considered that the most practical approach for capturing these was using the Running Cost Method.	We have included some minor clarification to the criteria. Some further responses to the dot points are: -Similar in length to a large-scale technology project (clarification added) -We suggest looking at the ISP projections in the text. They show large-scale solar being built in all states but Tasmania. Lots of large-scale battery investment occurs too. -As the total cost method only applies to variable energy the profile is known and easily compared Also, if you have just swapped capacity with the standard solution there are no running cost savings to be had as noted in the report and other responses here.	Report Section D.5

ID	Theme	Stakeholder	Comment	Response	Where addressed (report/FAQ/No update)
			It also noted that it is difficult under this approach to adjust for differences between energy profile of additional DER and the standard solution, as the ratio of annual capacity factor only tells users about how much generation is provided in a year and does not provide any direction regarding the timing at which generation is provided.		
69	Running Cost Method	Frontier Economics for Ausnet	Considered that the Running Cost Method better reflects the benefit of DER, as it explicitly accounts for the timing in which DER is available where the Total Cost Method does not. It considered that there is no reason to expect that the half-hourly wholesale prices during periods in which solar is generating will change over time in line with the total costs of large-scale solar generation. It did not consider that there was any reason to consider that the SRMC will move over time in line with the index of the change in total costs of large-scale solar generators which mainly consist of capital costs. It further sought to demonstrate that while the ESC's FiT has been volatile over time, there is no clear evidence to suggest that it has trended lower over time, as illustrated by Figure 2 of its submission which compares the minimum FiTs determined by the ESC and an index of capital costs of large-scale generators over time. In contrast it notes that the AEMO's estimates of solar capital costs have clearly trended significantly lower over time, which suggests	Previously addressed in other responses. Running costs savings do not exist if a close substitute for BAU technologies is deployed and crowds out the BAU deployment Previously addressed in other responses with clarifications made in the report. This is not our preferred approach but is a reasonable second best given projected investment in large-scale solar and price signals implied by that. Our preferred approach is centrally-provided half-hourly price projections. Previously addressed in other comments. Published FiTs were estimated over a period of historically high prices. It is considered unlikely that a downward trend in daytime prices will not proceed from increased small-scale and large-scale solar deployment. Historical prices (2017 to 2019) are not evidence of future long-term trends	No update required

ID	Theme	Stakeholder	Comment	Response	Where addressed (report/FAQ/No update)
			that the change in the total costs of large-scale solar has been a very poor predictor of the wholesale value of exported electricity over this time.		

Appendix C Overview of DER integration related reforms

Table 12 – Overview of DER integration related reforms

Description of DER policy/market reform area	Relevancy to Value of DER study
***AEMC Electricity Networks Economic Regulation Framework Review 2019* – identifies the tools crucial to integrating DER and optimising benefits to all customers.**	Outlines key reform areas to address regulatory gaps and barriers to integration. This study directly relates to and feeds into action item 4 of the AEMC Grid of the future work plan.[44]
***Distributed Energy Integration Program* (DEIP) – an ARENA-led initiative that brings together market authorities, industry and consumer associations to maximise the value of customer DER to the energy system and all energy users.**	Considering a range of reforms that cut across customers, markets, frameworks and interoperability. Current focus is on access and pricing arrangements to support DER uptake and integration. Complementary but in general outside of scope of this Study.
***Open Energy Networks Program* – joint undertaking by AEMO and the Energy Networks Association (ENA) aimed at developing a distribution operating model for integrating DER and identifying required network capabilities to support DNSP's transition to being an enabling platform.**	Investigates solutions to optimise and manage DER impacts on distribution networks, and to facilitate DER participation in the wholesale energy markets. Work is complementary but in general outside the scope of this Study.
***AEMC Demand Response Mechanism* – introduces changes to the NER to allow consumers to sell demand response in the wholesale market either directly or through specialist aggregators.**	Provides a mechanism for engaging demand side in central dispatch. Complementary to Study as forms a potential value stream.
***Evolve DER Project* – an ARENA funded collaborative effort between industry, academia and government to achieve outcomes for customers and increase the network hosting capacity through maximised DER participation in energy, ancillary and network services markets, while ensuring electricity network technical limits are not exceeded.**	Calculation and publication of operating envelopes for DER connected to distribution network. Relevant to DNSP identification of needs but out of scope for this Study.
***ARENA DER Hosting Capacity Studies* – aims to demonstrate issues faced by distribution networks in maintaining security and quality of supply in the context of increasing DER penetration.**	Aims to provide a methodology for considering impacts from increasing DER penetration and baselining hosting capacity. Relevant to assessing identified need/investment driver but outside of scope of this Study.
***Pricing and integration of DER* – report by Oakley Greenwood for ARENA aimed at examining the optimal way for providing price signals that reflect the value of services DER provides to the electricity supply chain.**	Looks at appropriate pricing structures for sending price signals to customers for investing DER such as solar and batteries. Relevant to customer decision-making and DNSP investment but out of scope of this Study.

[44] https://www.aemc.gov.au/our-work/our-forward-looking-work-program/integration-of-DER/grid-of-future

Description of DER policy/market reform area	Relevancy to Value of DER study
***Energy Security Board Post 2025 Market Design Review* – aimed at exploring the design of what a two-sided market (where all types of energy users actively buy and sell electricity) could look like.**	Looks at the design features of promoting interaction between suppliers and customers so that customers or/and those who participate in the wholesale market on their behalf will be active in responding to price. Relevant as a potential investment driver but largely out of scope of this Study.
***Technical standards development* – for devices, information sharing, and protocols currently being developed through the update to the AS/NZS 4777 standards and Application Programming Interface (API) working group. AEMO also have made a rule change request to the AEMC to place an obligation on AEMO to develop DER Minimum Technical Standards.**	Looks at resolving technical issues surrounding DER connection and control. Relevant to operation of DER and ability to capture DER value but out of scope for this Study.
***Government of South Australia: Department of Energy and Mining – Consultation on Regulatory Changes for Smarter Homes* – South Australian Government is currently consulting on a package of regulatory changes to jurisdictional arrangements relating to retail tariffs, smart meter technical standards, smart inverter standards, remote connection and disconnection of DER, and export limits.**	The proposed changes to jurisdictional arrangements in South Australia are aimed at facilitating greater uptake and integration of DER. The proposed changes to smart meter and inverter technical requirements and export limits are relevant in the sense that they will support improved voltage management capability and dynamic export limits to enable more hosting capacity but are generally outside the scope of this Study.
***AEMC review of Stand-Alone Power Systems and microgrids* – provides a package of rule changes to implement a new regulatory framework for stand-alone power systems.**	Has some relevancy in terms of investment drivers but is generally outside the scope of this Study.
***Regulatory Sandboxes* – seeks to establish a framework which would allow participants to test innovative concepts in the market under relaxed regulatory requirements at a smaller scale, on a time-limited basis and with appropriate safeguards in place.**	Complimentary in the sense that it may accelerate new DER service offerings and demand response but is generally considered outside scope of this Study.
***AEMO Rule change – Integrating Energy Storage Systems (ESS)* – aimed at defining and providing a framework that supports ESS participation in the NEM.**	Relevant in terms of being a potential investment driver but is outside the consideration of this Study.
***AER consideration of Tariff Structure Statements* – aimed at promoting cost-reflective pricing to support efficient decisions about the deployment of DER.**	Aims at promoting cost-reflective pricing and removing cross subsidies. Relevant to DER price signalling but out of scope of this Study.

Appendix D Existing Approaches to Valuing DER

We have undertaken a literature review of exiting methods aimed at quantifying the value of DER. Listed below are the various methods used in Australia and internationally for valuing DER benefits which have been reviewed as part of preparing this Final Report.

Australian methods

- Essential Service Commission (ESC) – Feed-in Tariff (FiT)[45]
- SA Power Networks (SAPN)/Houston Kemp – Avoided dispatch costs and VPP[46]
- CitiPower/Powercor/United Energy (UE)/Jacobs – Market Benefits for Solar Enablement - avoided generator short run marginal costs (SRMC)[47]
- AusNet (Frontier Economics) – Value of relieving constraints on solar exports[48]
- Jemena - Attachment 05-04 – Future Grid Investment Proposal [49]
- CSIRO/Open Energy Networks (OEN) – review of cost benefit frameworks for DER integration[50]

International methods

- Electrical Power Research Institute (EPRI) – Time and location value of DER[51]
- Rocky Mountain Institute – Value of battery storage[52]
- New York (NY) – Order on net energy metering transition, phase one of value of distributed energy resources, and related matters[53]
- United Kingdom (UK) – Energy Networks Association/Baringa Partners: Future World Impact Assessment[54]

A summary of value streams and valuation methodologies considered by these studies is provided in Table 13 (Australian approaches) and Table 14 (international approaches) while a summary of observations from our review is provided in Sections D.1 to D.7 below to provide insights on the approaches adopted.

D.1 Granularity (Spatial)

A high level of spatial granularity is used for calculating network augmentation benefits as these benefits tend to be highly dependent on location. However, one source which calculates benefits at a national level takes a high-level approach to network augmentation benefits that does not consider spatial effects.

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[45] Essential Services Commission 2017, *The Network Value of Distributed Generation: Distributed Generation Inquiry Stage 2 Final Report*, February 2017.

[46] SAPN, Supporting Document 5.20 - Houston Kemp: Estimating avoided dispatch costs and VPP - Jan 2019 – Public.

[47] Jacobs, 'Market Benefits for Solar Enablement: Victoria Power Networks and United Energy – Final Report,' Rev 1, 15 August 2019.

[48] Frontier Economics, 'Value of relieving constraints on solar exports: A report for AusNet Services,' 16 October 2019.

[49] Jemena Electricity Networks Vic Ltd, 2021-26 Electricity Distribution Price Review Regulatory Proposal, Attachment 05-04: Future Grid Investment Proposal (Public), 31 January 2020.

[50] Graham, P.W., Brinsmead, T., Spak, B. and Havas, L. 2019, *Review of cost-benefit analysis frameworks and results for DER integration*. CSIRO, Australia.

[51] *Time and Locational Value of DER: Methods and Applications.* EPRI, Palo Alto, CA: 2016. 3002008410.

[52] Fitzgerald, Garrett, James Mandel, Jesse Morris, and Hervé Touati., *The Economics of Battery Energy Storage: How multi-use, customer-sited batteries deliver the most services and value to customers and the grid*, Rocky Mountain Institute, September 2015.

[53] State of New York, Public Service Commission, 'Order on net energy metering transition, phase one of value of distributed energy resources, and related matters,' March 9, 2017.

[54] Baringa Partners LLP, 'Future World Impact Assessment,' 22 February 2019.

Other benefit types tend not to be applied spatially and include averaged effects over wider regions such as states. Where location-based marginal prices are available, they are used for wholesale market benefits which results in variation of the value of wholesale market benefits across regions, although these regions are relatively large.

D.2 Applications

There have been several studies both in Australia and internationally which set out approaches for valuing DER benefits. The majority of these studies have been prepared for applications which differ from the context described here, in particular to develop feed-in tariff rates for DER customers and tend to focus on wholesale market benefits. Nevertheless, they provide valuable insight into the methods various parties have used to determine the value of DER.

D.3 Value streams included

Most of the studies reviewed tend to focus on wholesale market benefits. Where network benefits are considered, the studies suggest that these have very significant spatial variation and so it is not appropriate to set a value at an all-of-network or jurisdiction level.

D.4 Valuation streams considered and methods

Electricity generated

The most common approach to valuing the electricity generated by DER is to use wholesale prices. An average value is calculated from annual pricing data weighted by the output of the DER generator, so prices at times when DER generation is zero do not contribute to the value.

Wholesale prices are mostly used for calculating short-term benefits. This includes feed-in-tariffs for customers, which are updated at least annually and only apply for a single year. The uncertainty in future wholesale prices reduces the accuracy of long-term forecasts using future prices as a key input.

The wholesale prices used are those that would be available to a similarly located centralised generator, so in jurisdictions where location-based pricing is available, the location-based prices are used. In all cases, the wholesale prices are adjusted for avoided network losses, which is similar to how centralised generators are compensated. Two sources, which provided business cases for DER enablement investments to the AER, used avoided generator dispatch costs rather than wholesale prices.[55]

It should be noted that most of the sources that used wholesale prices were calculating compensation to DER owners, rather than for valuing benefits of DER integration investments by

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[55] Refer to SAPN, Supporting Document 5.20 - Houston Kemp: Estimating avoided dispatch costs and VPP - Jan 2019 – Public and Jacobs, 'Market Benefits for Solar Enablement: Victoria Power Networks and United Energy – Final Report,' Rev 1, 15 August 2019.

utilities. In the context of setting FiTs, the use of wholesale prices is appropriate as it is aimed at calculating benefits to individual customers as opposed to trying to calculate the benefit to the broader market.

The application of feed-in tariff rates or wholesale prices to DNSP investments must be treated with caution. The use of a FiT or wholesale prices as a proxy for value of DER is based on these values representing the economic benefit of avoided fuel costs by centralised generators (and sometimes environmental benefits). FiTs and wholesale prices may incorporate generator ramping costs, start-up/shut-down costs, portfolio bidding strategy effects, effects of plant availability decisions and a multitude of other factors, not all of which represent economic benefits. Wholesale prices are only loosely linked to generator short-run marginal costs (SRMC), of which fuel costs make up the majority. Wholesale prices can be seen to diverge significantly from estimated SRMC of generators at times.

Wholesale Generation Capacity value

In most studies that include capacity value, the local jurisdiction has a capacity market or similar capacity price that can be used.

Avoided network augmentation

Most studies that include avoided network augmentation as a benefit use a location specific calculation of the avoidable costs, typically by comparing costs where DER is used to a counterfactual where traditional network augmentations are used. In some cases, external sources for the value of avoided augmentation are used, such as a published demand relief value or marginal cost components of tariffs.

Greenhouse gases

Studies tend to use a value from an external source. Where available, this is a government mandated carbon price, such as the social cost of carbon or similar values used by governments/regulators.

D.5 Treatment of Uncertainty

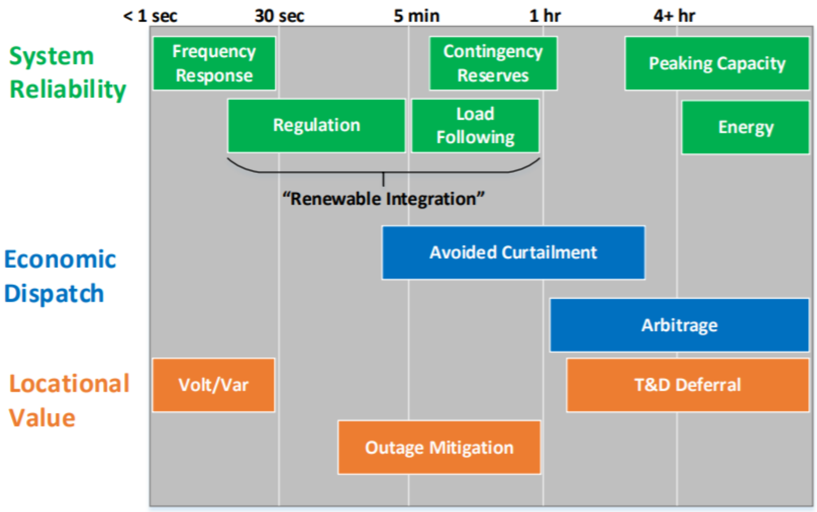
Most of the studies reviewed rely on third-party sources for the unit rate used to value DER benefits. For example, some network business cases provided to the AER use a regulated feed-in-tariff as the unit rate of DER wholesale market benefits. This approach avoids direct consideration of uncertainty in the unit rate as the external source can be quoted as being a set value.

Each of these unit rates, which are determined either via a regulated market or set by a regulator, treat uncertainty differently (or not at all). In the studies reviewed, none considered the uncertainty that may be incorporated into the unit rates obtained from third-party sources nor planned for this uncertainty. Our review did not explore the methodologies used for the calculation of unit rates by third-party sources.

Network augmentation benefits generally have the highest level of uncertainty. This is usually addressed via sensitivity testing of the key assumptions to determine whether moderate changes would influence the investment decision and therefore the avoidable costs.

D.6 Granularity (Temporal)

Temporal granularity is linked to the benefit, as highlighted by Figure 13 which shows the time scale variance between different benefits.



Source: Northwest Power and Conservation Council, 'White Paper on the value of energy storage to the future power system,' November 2017, p. 7.

Figure 13 – Temporal nature of DER value streams

The Methods reviewed in this Study considered market benefit timing of DER generation and market settlement intervals so that a weighted average price is used. However, once the average price is calculated, most of the studies apply the rate uniformly to all DER generation regardless of timing.

Network benefits are calculated based on timing of peak demand. These benefits consider the expected output of DER generators at the time of peak demand.

The studies reviewed did not consider avoided costs of minimum demand.

D.7 Use of counterfactuals

Counterfactuals are widely used for valuing avoided network augmentation costs, where the counterfactual is a scenario where a network investment is used to manage constraints that may be managed by DER in the alternate scenario. Counterfactuals are often also used for wholesale generation capacity/resource adequacy, which typically examine the cost of the avoided peaking generation resource.

None of the studies reviewed considered alternative uses of constrained solar, such as self-purchase of batteries or consumption shifting.

Table 13 – Summary of existing Australian methods

Benefit Type	Value Stream	ESCV (Vic FiT)	SAPN (Houston Kemp)	CitiPower/Powercor/UE	Jemena	Ausnet (Frontier Economics)	CSIRO/ENA (OEN)
Wholesale market	***Avoided marginal generator SRMC***	✓ Wholesale market prices	✓ Avoided generator SRMC	✓ Avoided generator SRMC	✓ Wholesale market prices (Vic FiT)	✓ Wholesale market prices (Vic FiT)	✓ Suggestion only, no calculation methodology suggested
	Avoided generation capacity investment	-	-	-	-	-	-
	Essential System Services	-	-	-	-	-	✓ Suggestion only, no calculation methodology suggested
Network	***Avoided/deferred transmission augmentation***	-	-	-	-	-	✓ Suggestion only, no calculation methodology suggested
	Avoided/deferred distribution augmentation	-	-	-	✓ Reduced load and lifetime extension	-	✓ Suggestion only, no calculation methodology suggested
	Distribution network reliability	-	-	-	-	-	-
	Avoided replacement/asset derating	-	-	-	-	-	-

	Avoided transmission losses	✓ Loss factors	✓ Loss factors	✓ Loss factors	✓ Loss factors (Vic FiT)	✓ Loss factors (Vic FiT)	✓ Loss factors
	Avoided distribution losses	✓ Loss factors	✓ Loss factors	✓ Loss factors	✓ Loss factors (Vic FiT)	✓ Loss factors (Vic FiT)	✓ Loss factors
Environment	***Avoided greenhouse gas emissions***	✓	-	✓ ACCU price	✓ (Vic FiT)	✓ (Vic FiT)	-
	Reduced health impacts of air pollution	-	-	-	-	-	-
Customer	***Willingness to pay for other perceived benefits (e.g. energy independence)***	-	-	-	-	-	-

Table 14 – International approaches to valuing DER

Benefit Type	Value Stream	EPRI	Rocky Mountain Institute (value of battery storage)	New York VaDER Order	UK ENA (Baringa)
Wholesale market	***Avoided marginal generator SRMC***	✓ Location-based marginal price	-	✓ Day ahead, hourly location-based marginal price	-
	Avoided generation capacity investment –	✓ Capacity protocols followed by regulators	-	✓ Capacity market prices	✓ Capacity market prices
	Essential System Services	-	-	-	✓ % reduction in current market value
Network	***Avoided/deferred transmission augmentation***	✓ Case study specific using options analysis	-	✓ Existing pricing mechanisms	✓ (capacity) Based on tariff model ✓ (voltage) Linear extrapolation of a study
	Avoided/deferred distribution augmentation -	✓ Case study specific using options analysis	-	✓ Existing pricing mechanisms	✓ Based on tariff model
Network	***Distribution network reliability***	-	-	-	-
	Avoided replacement/asset derating	-	-	-	-
	Avoided transmission losses	✓ Loss factors	-	✓ Loss factors	-
	Avoided distribution losses	✓ Loss factors	-	✓ Loss factors	-
Environment	***Avoided greenhouse gas emissions***	✓	-	✓	-

		Value used by participant network and regulator		Renewable energy certificate/social cost of carbon	
	Reduced health impacts of air pollution				
Customer	***Willingness to pay for other perceived benefits (e.g. energy independence***	-	✓ -	-	-

Appendix E Method selection

Overview

Valuation method selection

When a network invests in increased hosting capacity the investment and behavioural/operational response can occur in generation, network and customer segments of the supply chain. However, the relevant benefits only occur in either the generation or network sector since any changes in customer load, generation or DER capacity can be expressed as inputs to understanding the changed investment or operational requirements in generation and network sectors.

For wholesale market located benefits of increased hosting capacity, there are two approaches a network may take to account for the value brought to that sector: a “longhand” approach using detailed electricity system modelling or a “shorthand” approach, which makes simplified assumptions for wholesale market benefits.

For network located benefits of increased hosting capacity, there is generally only one way to calculate network benefits which is the normal network investment planning processes as described in the RIT-T and RIT-D guidelines. However, we do discuss 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.

The recommended method 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. Where a type of benefit derives from a specific project, such as asset replacement, networks should continue to be evaluated using the existing RIT-T and RIT-D guidelines. The existing guidelines include an average value for customer reliability which could be used to evaluate an increase reliability delivered through increased adoption of DER capable of maintaining supply through fault conditions. However, a new shorthand method based on average avoided cost may be appropriate for broad-based projects that avoid a non-project-specific network augmentation.

For wholesale market benefits, it is recommended the choice of methods be based on the project characteristics. The key characteristics of the project are its scale (in terms of the amount of additional DER supply) and the expenditure required to achieve the outcome. Small scale and low cost projects can justifiably use the shorthand method. This approach is likely conservative and avoids losing a significant share of benefits to the cost of commissioning electricity system modelling. It is important that the correct shorthand method is chosen, for which further guidance is provided.

Large scale and high cost projects should use electricity system modelling. We suggest defining large scale at roughly 50 MW or more of expected DER enablement (which would correspond with multi-million dollars of benefits). Any electricity system modelling should follow best practice as set out in the RIT-T and RIT-D guidelines.

Shorthand method selection and implementation

The report describes, assigns, and tests five different “shorthand” methods to valuing the incremental benefit of additional DER enabled by network investment. Shorthand methods are those that can be carried out in a spreadsheet application. One example of a shorthand approach is the use of feed-in tariffs to proxy wholesale market benefits in recent Victorian distribution network five-year planning submissions. Such a shorthand approach has two primary benefits: It can avoid the cost and complexity of whole of system modelling, and it can help provide a frame of reference when whole of system modelling is conducted to see if the benefits identified in that modelling are reasonable.

Because shorthand methods simplify and disaggregate the process of modelling the entire electricity system, they have the potential to significantly over or underestimate the value of DER that networks may unlock through DER integration projects. Accordingly, this section identifies the appropriate shorthand method to apply to a service provided by DER for a given network’s circumstances and the steps that must be taken to appropriately apply the method. Following this guidance will help networks identify values that are reasonable, albeit conservative for the benefits enabled by DER.

Process for assigning a calculation method for services provided by DER

To simplify the exercise, we have highlighted the five common services DER provides and identified five distinct methods to calculate the value of each service. The relationship between the services and methods is outlined in Table 15.

Table 15 – DER services and shorthand calculation Methods

Service	Method
1. **Variable energy**	Generation Total Cost (A)
	Generation Running Cost (B)
2. Flexible energy	Generation Running Cost (B)
3. Flexible capacity	Generation Capacity (C)
	Network Capacity (D)
4. Combined services	Generation Total Cost (A)
	Generation running Cost (B)
5. Environmental policy requirement	Generation Running Cost (B)
	Environmental price method (E)

Determining which method to use for which service requires some understanding of the broader context in which the DER is being enabled. Networks can determine which methods to use for their circumstances and if and how the values determined by those methods can be added together by considering the following questions:

- Is investment avoided?
  – What is the scale and time period of the additional DER enabled by the network?
  – Is there a need for the standard service (e.g. flexible generation) additional DER might avoid?
  – To what extent does the additional DER substitute for the standard solution?
- Should avoided running costs be considered a benefit?
- Is it appropriate to add benefits together?

After exploring these questions we conclude with a decision tree for assigning the appropriate method to each service given a network's circumstances.

The sectoral location of benefits

The value of increase in DER hosting capacity can be represented by the formula:

$$\begin{aligned} Value\ of\ an\ increase\ in\ DER\ hosting\ capcity =\ & Investment\ costs_{(inc\ hosting\ capacity)} \\ & + Operating\ costs_{(inc\ hosting\ capacity)} + Enviro\ outcomes_{(inc\ hosting\ capacity)} \\ & -\ Investment\ costs_{(BAU)} - Operating\ costs_{(BAU)} - Enviro\ outcomes_{(BAU)} \end{aligned}$$

In this case the increased hosting capacity represents the scenario with the proposed investment by a network. While some of the relevant investment and behavioural changes will occur at the customer site, all of the relevant benefits occur either in the generation sector or network sector. The investment and behavioural changes by customers or owners of DER are therefore inputs to determining the benefits to the generation and network sectors. Owing to differences in these sectors, the methods applied to evaluate benefits in each sector are different.

Wholesale generation sector

Electricity system models which represent the financial and physical attributes and operation of the electricity system over time are the most accurate tools for calculating the benefits of actions to increase hosting capacity which may result in additional DER energy and capacity in the wholesale generation sector. An example of such modelling was conducted by SAPN for their most recent 5-year planning submission.

However, in circumstances where a proposed action can be achieved with modest expenditure, the cost of conducting an electricity system modelling study may be inappropriate. In such cases, shorthand methods which we define as methods where the calculation of benefits could be carried out in a spreadsheet application, should be considered a reasonable alternative. An example is the use of feed-in tariffs to proxy wholesale market benefits in recent Victorian distribution network 5-year planning submissions.

As long as an appropriate counterfactual scenario is applied, electricity system models provide confidence that the correct benefits are captured net of any market impacts, and issues such as double counting are avoided. However, with shorthand methods there is less confidence, because the analysis is simplified and partial relative to the complexity of a dynamic system. Therefore, any shorthand method must be well targeted, so that the method is capturing only the relevant benefits. We discuss selection of the right shorthand method in the next section.

There are two main considerations when determining whether to use a shorthand method instead of electricity system modelling: conservatism and materiality.

Conservatism

Assuming the methods are well targeted, shorthand method benefit calculations could be considered similar or slightly more conservative than an electricity system model method, particularly for shorter time period projects. This conservativism results from shorthand methods not capturing all market dynamics of increased hosting capacity. Shorthand methods use historical prices and outcomes to determine their impact, which means they assume their supply volume has no impact on the market price. However, if the volume is large enough, additional DER supply could increase competition removing a higher cost marginal supplier that was previously setting the price[56]. Shorthand methods are also not likely to capture increased consumption as a result of lower electricity supply costs which is another benefit, although likely small due to inelastic demand.

The ability to assess conservatism of shorthand methods becomes less clear as the time period of the benefits being calculated increases. Electricity system models can project market outcomes over time, updating the nature of the market for other new entrants or for price induced demand increase, which the model can consider as required according to least cost planning principles and demand elasticities built into the model design. However, shorthand methods have to make manual adjustments for changes in the market over time. These manual adjustments are necessarily simplified and may over or underestimate changes in market values.

Materiality

While market modelling is the preferred approach for calculating DER benefits, it is expensive and time consuming, so the benefits being identified by the network investment should be materially significant to justify the expense of modelling. There are two aspects to determining the materiality of benefit calculation methods: one is the value of the benefits and the other is the cost of the overall network investment.

Electricity system modelling can be expensive. In some of the examples we present in the next two sections, an additional megawatt (MW) of DER supply is found to provide tens to hundreds of thousands of dollars in benefits depending on the type of service it is providing. If a network already has an idea of the scale of additional DER being enabled, this general value per MW might provide some guide as to whether electricity system modelling could be justified (in the sense that electricity modelling should not be carried out if a substantial portion of the benefits are offset simply by the cost of the modelling).

Looking at the problem of materiality from the aspect of network project costs, there is an existing guideline relating to regulatory investment test (RIT) projects that sets a threshold of $6m over which electricity system modelling is required. Outside of RIT projects, networks must apply their

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[56] The Technical Concepts sub-section at the end of this section provides a more technical discussion of the conditions when price may underestimate the increase in producer surplus

judgement to determine what level of effort is necessary to support prudent and efficient investment.

Selection

Based on these observations the recommended method selection process is shown in Figure 14. The key characteristics of the project are its scale in terms of the amount of additional DER supply and the expenditure required to achieve the outcome. Small scale and low cost projects can justifiably use the shorthand method. This approach is likely conservative and avoids losing a significant share of benefits to the cost of commissioning electricity system modelling. It is critical that the correct shorthand method is chosen (the process for which is discussed in the next section).

Large scale and high cost projects should use electricity system modelling. A suggested threshold for scale is around 0.1% of capacity in the state. This should allow for expected benefits being at least in the zone of multiple millions.

The life of the project was also considered as a potential selection criteria (i.e. disqualifying longer-lived projects from use of shorthand methods). Longer-lived projects have a greater risk of inaccuracy in some data inputs if not drawn from market modelling in shorthand methods. However, these can be addressed through data adjustments over time which we include in the methods. We also recommend some inputs to the shorthand methods might be developed from other modelling.

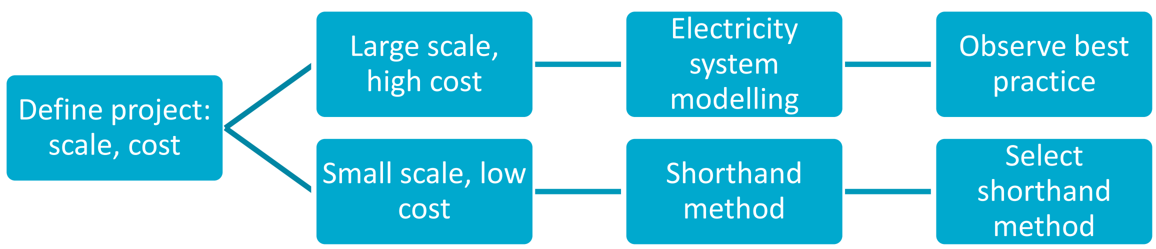


Figure 14 – Recommended method selection process, wholesale sector benefits

If electricity system modelling is selected it is important that best practice approaches are used. These practices are described in RIT-T and RIT-D guidelines. However, the following list highlights some selected topics:

- The counterfactual should be designed to include all plausible market changes, including competition that would normally enter the market that might impact the value of the additional DER supply. A plausible counterfactual would include, for example, ongoing changes in the large-scale generation mix, deployment of large-scale electricity storage and increased deployment of rooftop solar, batteries and other DER.

- The default source of assumptions should be the most recent AEMO ISP input and assumptions workbook which is published by AEMO. Selection of alternative assumptions would require justification.
- Inclusion of a balanced set of alternative scenarios or probability weighting of scenarios should be used to determine scenario weighted outcomes.

Electricity system modelling is less transparent than spreadsheet calculations. To address this, electricity system modelling should provide substantial data reporting rather than simply charts in a report. Something similar to the ISP assumptions workbook should be provided on the input side. Furthermore, outputs that exceed ISP output reporting should also be provided. In particular, a DER valuation will need to include half hourly price and generation data samples that demonstrate the impact of additional DER relative to the BAU (which is not currently reported by AEMO).

Network sector

For network benefits of additional DER, there is generally only one way to calculate network benefits which is the normal network investment 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.

Reductions in network transmission and distribution losses should be calculated using wholesale sector generation methods since the avoided costs occur in that sector. For the network sector we are concerned with avoided/deferred augmentation or replacement and reliability benefits.

Avoided/deferred augmentation

Network investment planning for augmentation and replacement typically deals with specific projects, but where the proposed DER hosting capacity augmentation is broad based or otherwise expected to contribute only to long-term non-specific transmission benefits (avoided/deferred transmission), a shorthand average avoided cost approach may be appropriate. Each unit of reduced peak demand contributed by the distribution network to the transmission network should be valued at the annualised total unit cost of transmission network (e.g. in $/MW/yr), which can be estimated from historical demand growth and augmentation expenditure data. A proxy for the annualised total unit cost of transmission network could be derived from the monthly demand charge at the relevant bulk supply points that the transmission network charges the distribution network.

Theoretically, a similar shorthand approach could be applied to distribution benefits. In this case a network augmentation (e.g. an IT or visibility project) is used to increase hosting capacity. A deferred augmentation benefit is achieved when the primary augmentation increases DER availability that then causes the deferral/avoidance of another augmentation that would have otherwise been required.

Avoided replacement or asset derating

A network can realise avoided replacement or asset derating benefits where the increased hosting capacity investment leads to changes in 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

Consideration of these opportunities would tend to be asset specific and so could not be characterised as a broad-based non-specific benefit. As such there is no shorthand method recommended. The existing RIT-D approach should be followed.

Network reliability

This benefit occurs where DER can supply individual customers or local networks after network faults, reducing unserved energy and outage duration. This type of benefit is only likely to be realised where:

- the investment by the network encourages additional investment in battery storage (which would not otherwise be purchased)
- The additional battery investment is able to be islanded during a fault
- Outages of up to a few hours are relatively 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. Each avoided kWh of unserved energy is valued using the appropriate value of customer reliability (VCR) data as published by the AER. The VCR could be characterised as an existing example of a shorthand method that is already available in the existing guidelines. It represents and an average cost of outages across a broad community of customers.

Summary

The recommended method 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. Where a type of benefit derives from a specific project, such as asset replacement, networks should continue to be evaluated using the existing RIT-T and RIT-D guidelines. The existing guidelines include an average value for customer reliability which could be used to evaluate an increase reliability delivered through increased adoption of DER capable of maintaining supply through fault conditions. However, a new shorthand method based on average avoided cost may be appropriate for broad-based projects that avoid a non-project-specific network augmentation. Figure 15 summarises these options.

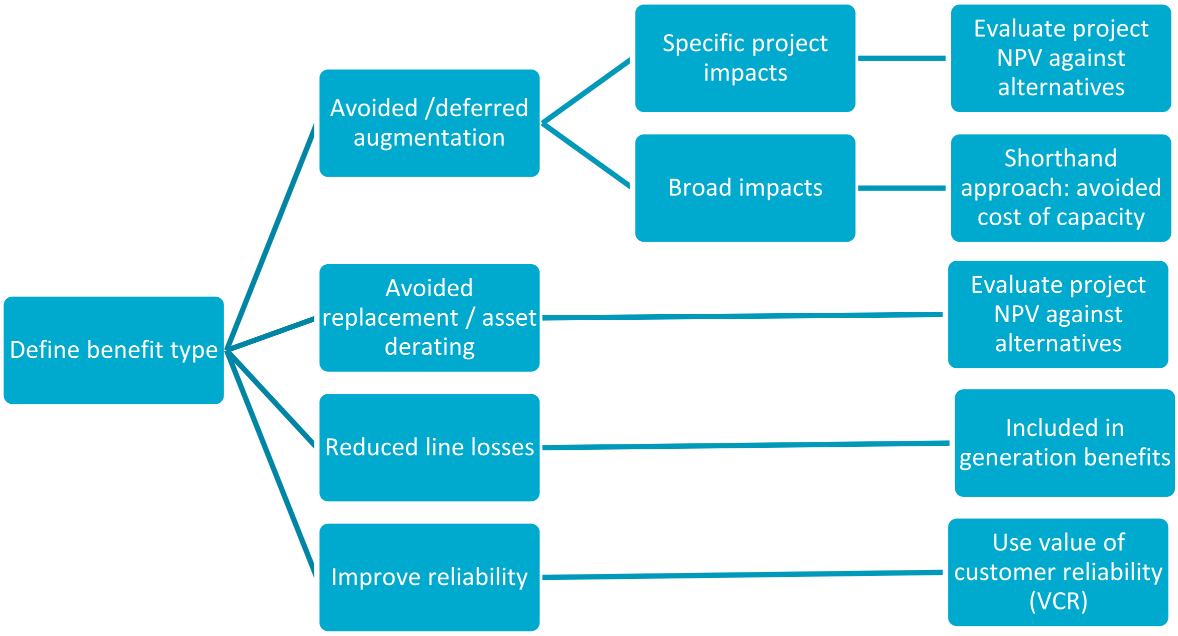


Figure 15 - Recommended method selection process, network sector benefits

Shorthand methods: selection and implementation

As discussed in the previous section, shorthand methods are simplified and partial relative to the complexity of a dynamic system. Therefore, any shorthand method must be well targeted, so that the method is capturing only the relevant benefits. With this requirement in mind, the key goal is to create a process for networks to follow which identifies the appropriate shorthand method to use for their circumstances and the steps that must be taken when applying it. This section sets out those steps; they are:

- Determine the type of benefit based on the characteristics or services that the additional DER provides and any additional policies in the relevant region;
- Determine the relevant part or parts of the supply chain for which benefits are being claimed;
- Determine which category of costs the additional DER enabled by increased hosting capacity avoids; and
- Apply the method assigned to that benefit type, avoided cost category and supply chain segment

Benefit type and supply chain segment

In considering the benefits of enabling additional DER, there are two main dimensions to consider:

- the segment in the electricity supply chain where the benefit occurs, and
- the type of benefit.

In the body of this report we discussed a list of potential benefits from different types of DER in providing services to different parts of the electricity supply chain. However, at a more generalised level we can say that DER provides only three types of services: energy, capacity and policy services. For example, providing DER services to the Frequency Control and Ancillary Services (FCAS) market is a capacity service, because the FCAS market requires a minimum capacity of FCAS capable capacity. The supply of additional DER to avoid transmission and distribution losses is an energy service because it avoids the need to generate additional energy.

A policy benefit is any government requirement on the market other than existing standards. This could include, for example, a renewable energy target or an emissions intensity target. These targets might be implemented as hard quantity constraints or prices (subsidies or taxes) that are design to enable a desired physical outcome. Either way a value is placed on additional DER that meets the requirements.

The body of this report also discussed various other benefits to customers. We set these additional customer benefits aside for the purposes of this discussion since methods for valuing those benefits in an objective way is an area for future development. Some suggested approaches have been included but will likely need more review before being include as a regular part of the valuation process.

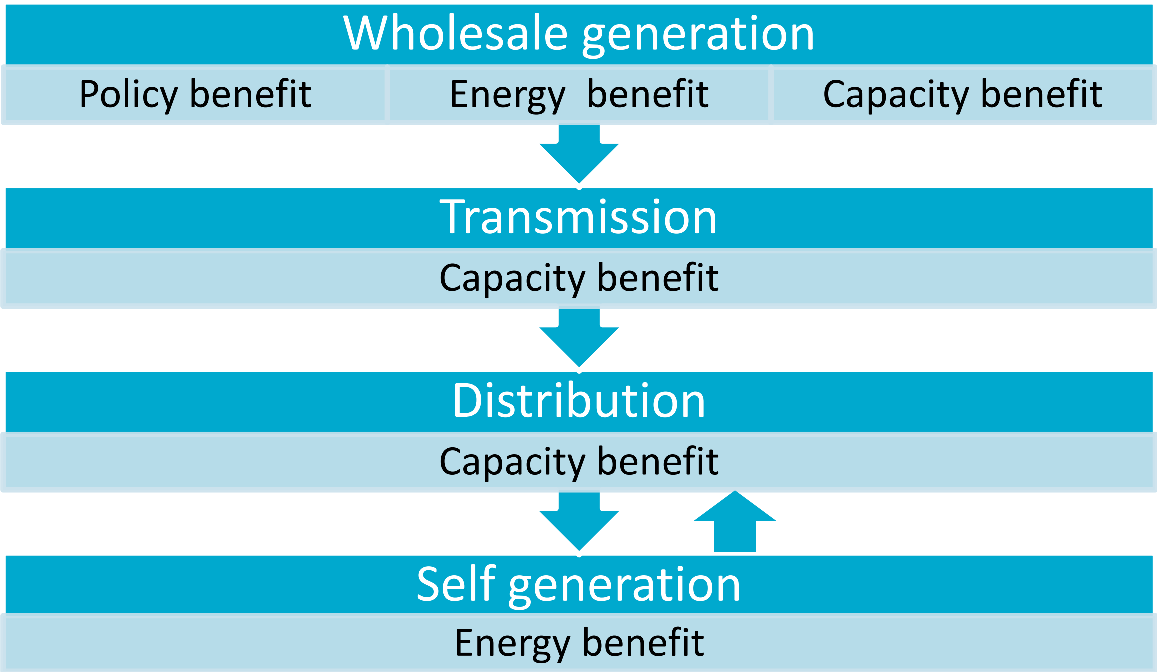


Figure 16 - Overview of benefit streams by stage in the electricity supply chain and type of benefit

The electricity supply chain starts with wholesale generation where there can be both energy and capacity benefits since both are required for this sector to deliver its function of meeting electricity demand at the required level of reliability. This part of the supply chain has also been subject to policies such as renewable energy targets, and so policy benefits are more relevant here than elsewhere (Figure 16).

The transmission and distribution parts of the supply chain only require capacity to achieve their required standards[57] but energy load shifting can have a similar outcome to additional capacity. DER owners who self-generate receive a benefit when they can generate more energy. They have no requirement for capacity when connected to the grid since the grid itself is their insurance

[57] An exception is where distribution companies provide off-grid services to remote communities but any benefit of additional grid enabled DER is not relevant in these circumstances.

against limited self-generation capacity. In practice, energy benefits in the self-generation sector are calculated in the wholesale sector since any shortfall in self generation is met by wholesale generation.

Using this simplified taxonomy of benefit types and supply chain stages, the recommended shorthand processes for calculating benefits from additional DER enabled by hosting capacity investment can be set out independently of the type of DER. However, we will explore specific DER examples further below.

Avoided cost category

There are two categories of costs which increased hosting capacity can avoid. One is total costs, which includes all capital, fuel and operating costs; the other is running costs, which includes only fuel and operating and maintenance costs. Avoided transmission losses are included in both types of avoided costs because when additional DER capacity is located next to the end user, it reduces both the amount of investment and operating costs required to meet demand. In the economics discipline, total costs and running costs are also referred to as “long run marginal costs” and “short run marginal costs,” respectively (A Technical Concepts sub-section at the end of this section provides a longer discussion of this economic terminology). When total costs are applied to electricity it also corresponds directly with another concept called “levelised costs of electricity” but this is only relevant in the sense that the calculation method is familiar to most stakeholders and well-established.

Running costs may be relevant in all time periods because all existing infrastructure is subject to running costs. However, total costs can only be avoided if we avoid a future investment decision. As a result, total costs are more difficult to determine as many factors need consideration.

Is investment avoided?

Whether the additional DER enabled by network actions is providing energy, capacity or policy services, those services would have otherwise been provided by the standard solutions in their supply chain segment. In the wholesale generation sector, large-scale generation technologies are the standard solution. In the network sector, standard solutions typically include operating or capital expenditure to replace or augment poles and wire infrastructure. Standard solutions for meeting the needs of these sectors can be found in the AEMO Integrated System Plan and 5-year planning documents of distribution and transmission companies.

Projects that enable additional DER will typically have lasting impacts. That is, a project that puts in place new systems to allow additional DER to connect to the network will likely last for many years or decades. However, such programs do not guarantee that additionally enabled DER will avoid the future construction and operation of the standard solution for any given supply chain segment.

Proponents should undertake the following steps to determine if investment in the standard solution is avoided:

- Determine if the network action results in an extended capacity for additional DER and over what period. If so,
- Determine if there was a need for the relevant standard solution to be deployed in that supply chain segment in the period of the additional DER enablement. If so,

- Determine if the enablement of additional DER is a reasonable substitute for the standard solution.

If all of these requirements are met then we can have some confidence that the additional DER has avoided the deployment of the standard solution (up to the amount of the additional DER enabled) and the total costs of the standard solution will feature in the benefit method (which we describe further below). We now expand on each of the steps.

Does the network action result in extended capacity for additional DER?

No strict guidance can be provided to answer this question since there are too many different types of enablement, e.g. tariff structures, control systems, and hard infrastructure. The general approach should be to establish through technical consideration of equipment performance or reasonable behavioural experience, a reasonable chain of causality between the action and the scale and time period of the enabled additional DER.

Is there a need for the relevant standard solution?

In determining whether there is a need for the standard solution, the first consideration should be what is the most standard solution for the service being considered. In previous sections we have said there are three broad services: energy, capacity and policy. However, in considering the methods for valuing additional DER, one should also consider whether the energy provided is flexible or not. Flexible energy is energy that can be managed by the owner (or their agent) and provided at varying times, particularly when the system has greatest need. Energy which is variable relates to that provided by variable renewable sources which are weather dependent.

With the additional consideration of flexibility, the services provided by the enabled DER fall into four categories:

- Provides variable energy (e.g. increased variable generation exports from rooftop solar PV)
- Provides flexible energy (e.g. increased exports or imports from a customer or community embedded battery)[58]
- Provides flexible capacity (e.g. increased capacity of demand managed devices on standby and able to deliver that capacity when called)
- Meets generation policy requirement (e.g. increased renewable energy generation from rooftop solar)

In this context, the standard solution for additional variable energy from rooftop solar PV would be large-scale solar PV generation. For flexible energy from customer or community embedded batteries, the standard solution would be large-scale storage given the close alignment of those technologies. For flexible capacity, a variety of DER could be enabled, such as demand response, batteries, and electric vehicles. The standard solutions in the wholesale generation sector that provide similar services could include large-scale storage as well as all large-scale flexible

[58] There are similarities between flexible energy and flexible capacity. However, the key difference is that flexible energy applications provides high value energy daily and the delivered energy is the main source of value. Its provision of energy at peak times, however, may also offset the need for other capacity. Flexible capacity provides a small amount of energy rarely and its capacity is the main source of value.

generation technologies (i.e. peaking plants). The properties (e.g. ramp rate) of the flexible capacity should be considered to narrow down the field to the closest like for like comparison.

In the network sector, the standard solution for flexible capacity would encompass anything that increases capacity but could focus on those solutions that have been included in five year planning. A key consideration in networks is *where* the standard solutions are being deployed. If DER is enabled in a part of the network where the standard solution is not being deployed because there is significant headroom, then the DER cannot be considered to be avoiding any standard solutions.

For wholesale generation, networks are advised to use the most recent AEMO Integrated System Plan (ISP) to determine if large-scale generation (flexible or otherwise) and storage solutions were likely to have been built in the relevant period and region. For example, Central results from the 2019 and 2020 ISP indicate that large-scale solar generation and storage will be deployed in all states except Tasmania in the next two decades. Peaking gas and liquids appear to be on the decline in most regions.

For additional DER generation that meets a policy requirement, the standard solution depends on the policy formulation, which varies by state. For renewable energy targets such as those in Victoria and Queensland, AEMO's Integrated System Plan indicates that wind and solar PV are the preferred large-scale solutions for wholesale generation. These are in roughly equal proportions in Queensland, but more dominated by wind in Victoria. This suggests equal proportions of wind and solar PV could be considered the standard large-scale renewable energy solutions but this view could be adjusted for more regional accuracy from ISP results. If instead an environmental policy came in the form of an emission target, any new build technology that remains below the emission intensity over the relevant period could be considered part of the standard solution set. Again, the ISP, which typically includes any mature environmental policy, should be studied for guidance.

To what extent does the additional DER substitute for the standard solution?

It is not enough that a standard solution is being deployed in the same generation region or network zone. To avoid the need to build the standard solution, the additional DER must provide the service at a similar or better level. The test for similarity depends on the type of service.

For energy services to be considered a substitute, the ratio of the annual capacity factor of the additional DER to the annual capacity factor of the avoided standard solution should be greater than or equal to 0.7[59]. This means that if the capacity factor ratio is lower than 0.5, the risk is too great that the standard solution might still be built and any cost savings voided. In other words, the additional DER has not substantially met the need.

The annual capacity factor is defined as:

[59] This implies that, at least 70% of the time the developer of the standard solution can be expected to be competing against the enabled additional DER and would therefore consider not deploying the solution or deploying a reduced capacity. Ordinary additional rooftop solar (the whole output, not just the additional part released by improved hosting capacity) would typically score around 55% on this ratio against large-scale solar PV due to most large-scale solar PV having single axis tracking which improves its capacity factor over non-tracking rooftop solar.

$$\frac{Generation\ in\ MWh}{Rated\ capacity\ in\ MW \times 8760}$$

In the case of the standard solution the rated capacity is the nameplate capacity in MW of any standard size generation site[60]. In the case of the additional DER the rated capacity is the peak additional energy output that is expected in a one hour period. Comparing average daily production profiles of the standard solution and the additional DER also provides a useful additional check.

The most common type of DER is rooftop solar and large-scale solar is its most obvious standard solution substitute. However, for flexible energy services from DER, the substitute is less obvious since new flexible energy generation can be provided by a range of technologies such as gas generation, batteries and pumped hydro which may be operated in a range of modes. Given the uncertainty about what flexible DER generation is competing against, there may be sufficient doubt to conclude that flexible DER energy has no direct substitute. As such, avoided investment costs are not a recommend method for valuing flexible energy on its own (but may still be relevant for combined services).

Capacity services are more straightforward because capacity is a rated property (whereas energy is an operational outcome). For capacity services to be considered a substitute, proponents should establish that the additional DER has similar technical properties to that of the standard solution and is available at similar expected times of need. For generation capacity, the speed of ramping is likely the most important technical feature. For the network sector, only the availability may be important. If the properties are identical or better, then it could be considered a substitute. If the properties are different but can be compared numerically via a ratio then we again propose a 0.7 threshold for substitutability. If the properties cannot be compared numerically in a reasonably straight forward manner, then, to be conservative, they should not be considered substitutes.

Increased hosting capacity may also result in combinations of DER energy and capacity services, for example from solar and batteries. In this case, proposed process is to find a matching large-scale service. In this example it would be large-scale solar and batteries. This matching process is proposed instead of a capacity factor based formula to determine substitutability because the operational profile is not fixed but rather subject to prices at any given point in time. If no obvious match or direct substitute can be identified, then we conclude that there is no investment avoided.

For environmental services to be considered a substitute, proponents should establish that the additional DER meets the same environmental standards as the standard solution in all relevant years. In the context of regional renewable energy constraints, the relevant properties might be a renewable energy source and zero emission factor. However, other schemes could have different requirements. The relevant legislation where operating should be used as a guide to eligibility.

[60] A proponent might also have access to normalised data such that the output has been indexed to peak production. In this case rated capacity is 1 and can be dropped from the formula.

When should avoided running costs be considered as a benefit?

First of all, if avoided investment costs are a potential benefit, then running costs cannot be separately considered. In other words, avoided total costs and running costs are not additive benefits; they are mutually exclusive. This is because, in the counterfactual (where the standard solution was deployed) and in the benefit case, the two options have been established as being close substitutes. The impact on the running costs of other infrastructure from deploying additional DER enabled by network investment rather than the standard solution should be near nil, as the additional DER is performing just like the standard solution and therefore other infrastructure performs as it does in the counterfactual as well.

Running costs can only be considered in the case where the additional DER fails the tests above in that it is either:

- Not available over an extended period (i.e. not similar to the life of a generation project),
- Is not needed by the sector in that generation region or network zone, or
- Is not a strong or direct enough substitute for the standard solution to be avoided or reduced.

In these circumstances, the additional DER is genuinely additional to what would have been deployed; it therefore can have an impact on the running costs of existing infrastructure. However, the value of those avoided running costs should be adjusted over time to account for expected changes in the market.

When is it appropriate to add benefits?

Plausible combinations that might be considered additional to each other include increased hosting capacity that enables additional:

- Variable energy and environmental services (e.g. rooftop solar)
- Variable energy, flexible energy and environmental services (e.g. rooftop solar and batteries)
- Flexible energy, capacity, and environmental services (e.g. customer or community embedded batteries combined with rooftop solar)

While variable and flexible energy may include environmental services, flexible capacity without a low emission energy source is unlikely to contribute to environmental services. Even if the energy source is low emission, it is possible the quantity of additional energy in the capacity services may be so low that the benefit from an energy service perspective or environmental services perspective is negligible.

Flexible energy or capacity without environmental services can be added if the enabled DER provides services in different parts of the supply chain. For example, load shifting might reduce costs in the generation and network sectors. Such an example is most likely where network and regional generation loads align closely. However, the benefit will generally be weaker in the network sector where savings are only real if they occur on the highest demand days in locations with poor headroom. However, in the generation sector, shifting energy may have value on most days due to regular price changes.

A strongly plausible combined benefit is the first one: energy and environmental services from an inflexible DER source. If the government that enacted the environmental services requirement have provided a clearly published external environmental services price, then that price should be used and is additional to the energy value calculated by the relevant avoided total or running cost benefit method. This price is outside the electricity market and therefore does not represent double counting.

However, if the price of environmental services is otherwise unclear, the larger of the two benefits – the energy or environmental benefit – should be used to avoid possible double counting from a market for environmental services which has been internalised within the electricity sector.

Benefit calculation method assignment

In the discussion above, we explained steps for determining the type of benefit, the relevant part or parts of the supply chain and whether the additional DER from increased hosting capacity avoids total costs or running costs only. With these steps complete, we are now able to assign a benefit calculation method summarised in Figure 17.

The next section provides the formulas and worked examples for each of the benefit calculation methods.

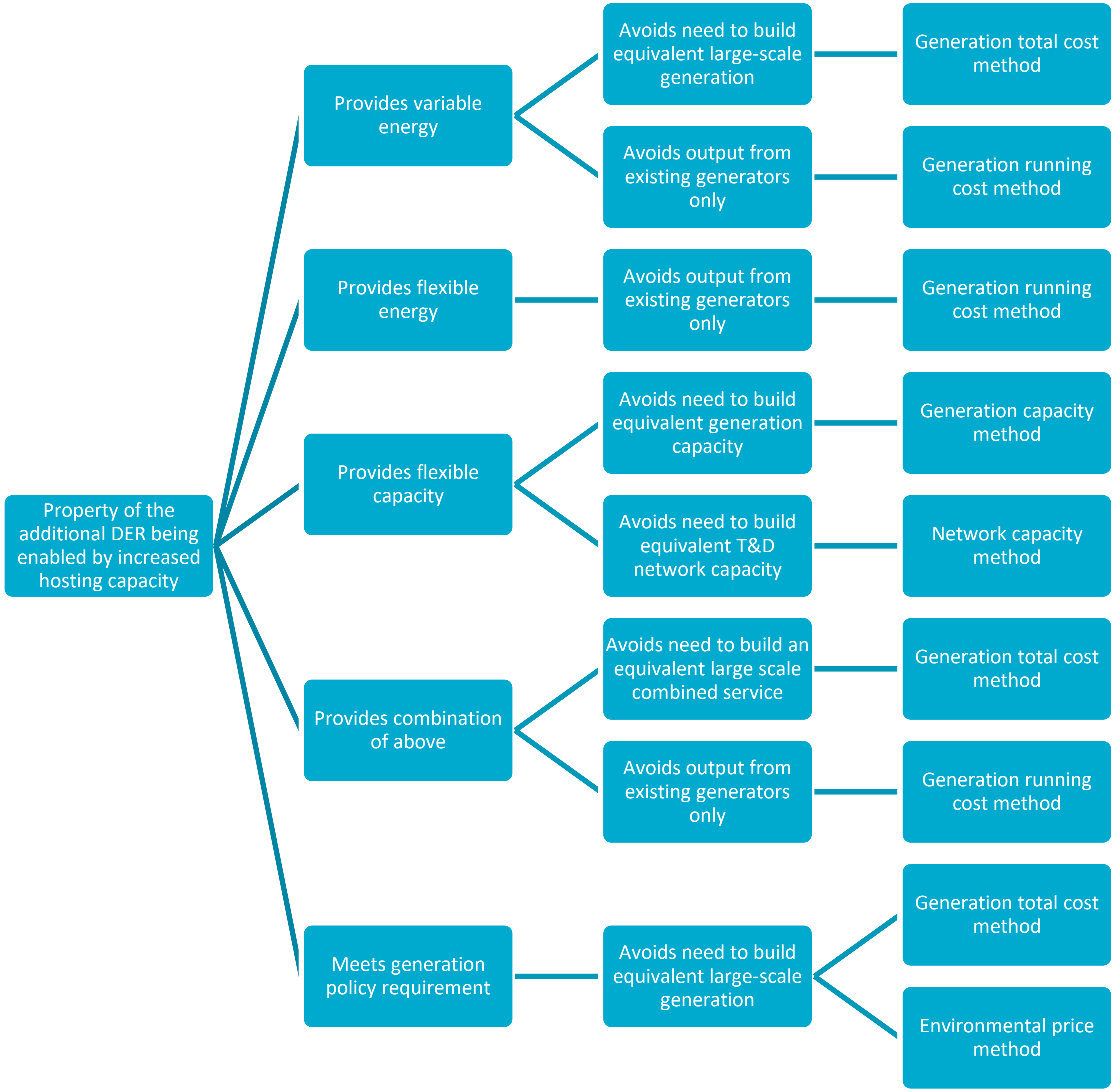


Figure 17 - Process guide for assigning a benefits calculation method based on the properties of the enabled additional DER

Technical concepts

Short-run and long-run marginal costs

Definitions

Short-run marginal costs (SRMCs) are costs that are incurred as a function of output. The more electricity you generate the more fuel you might use or the more materials and parts that will need to be replaced. Some parts of operating and maintenance costs are considered fixed (not a function of output) while others are considered variable with output and fall into the category of SRMC.

Long-run marginal costs (LRMC) include the components of SRMC plus fixed costs which do not vary with output. LRMCs includes capital costs and the fixed component of operating and maintenance. As such LRMC represent all costs that are necessary to break even. If a market is functioning well (meeting the requirements of good access to information and low barriers to entry and exit) the price should on average represent the LRMC of the technology/supplier required to meet the last unit of demand.

The electricity market is subject to reasonably long cycles of divergence from LRMC. This reflects the fact that the electricity market is characterised by long lived assets (20 to 50 years) which means entry to and exit from the market is slow. Combined with significant daily and seasonal variations in demand this means that there are periods of excess demand and supply. During periods of excess supply, suppliers must abandon their need to break even and treat their capital as sunk (meaning recovering the fixed component of their costs becomes a secondary goal). In these circumstances they 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 therefore in a position to set the price above their long marginal costs and in economic language, earn “super normal profits” while the excess demand period lasts.

Type of cost that is relevant for valuing additional DER

In the context of valuing additional DER in the wholesale market both SRMC and LRMC are relevant. If the additional DER means that the system can avoid building new generation plant than the value is the avoided LRMC of the new plant from the time it would have been built. The need for new capacity occurs in the following contexts:

- Growth in demand: This is a relatively small driver owing to the relatively flat demand profile in most regions
- Retirement of existing capacity: Depends mainly on the age profile of existing generation capacity in the region and also on the next driver
- Legislated requirements for change in the technology mix by a given date: This might flow for example from a regional renewable energy target or other climate policy mechanism

In each of these cases the type of generation capacity matters. Additional passive DER can only replace on a like-for-like basis passive (non- or semi-scheduled) wholesale generation. Flexible DER can replace flexible wholesale market generation capacity with similar properties.

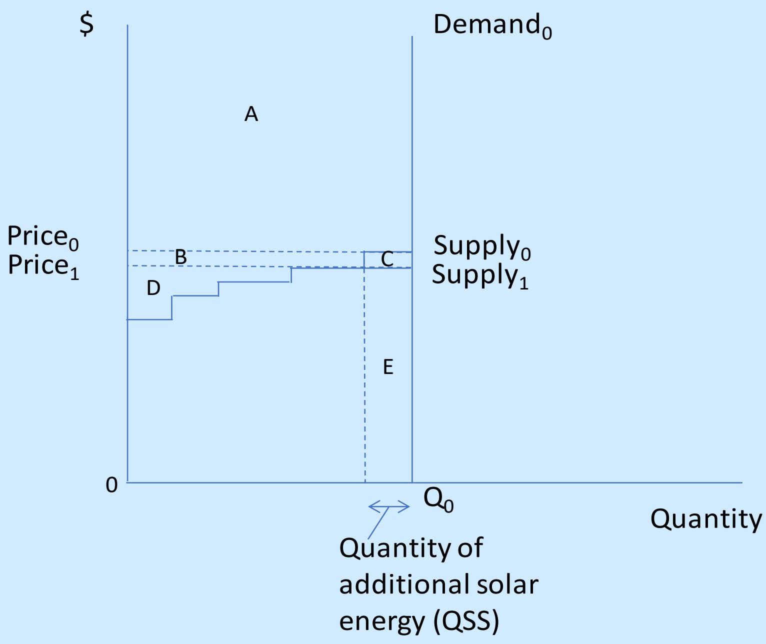
In a region where growth is flat, retirements are fairly distant and there is no required change in the technology mix, the additional DER is not likely to offset LRMC of new builds and so avoided cost calculations should focus on SRMCs. That is, additional DER only avoids another supplier incurring fuel and operating and maintenance costs.

Double counting

If allowing additional solar DER displaced large-scale solar capacity, the counterfactual is that there would have been the same amount of solar. The same amount of solar cannot displace the SRMC of other suppliers and therefore there is no market benefit to count.

Role of price in calculating consumer and producer surplus in wholesale generation

All benefit methods must satisfy the requirement that they calculate the change in the sum of consumer surplus (CS) plus producer surplus (PS). Figure 18 illustrates that in the context of inelastic demand, two types of measures may be consistent – short run marginal cost (SRMC), and prices changes – to evaluate the value of additional DER energy (which in this case we assume is rooftop solar PV). If the additional DER causes the price to drop then the valuation of that additional DER should be area C+E and using prices to measure this will be inaccurate (lower) by the area C. However, if the additional DER was on a flat part of the supply curve such that Price_1 was both the original and new price after the additional DER, then the price multiplied by the additional DER is equivalent to the improvement in consumer and producer surplus.



Lower cost supply from solar DER shifts price down such that:
CS_0=area between price and demand curve = A
PS_0=area between price and supply curve = B+D
goes to:
CS_1=area A+B+C
PS_1=area D+E
Improvement in PS+CS=area C+E

When demand is inelastic, PS+CS is equivalent to the difference in SRMC times displaced volume (Supply_0-Supply_1)*QSS=area C+E

Price as measure of change in CS+PS is (Price_0-Price_1)*QSS= area E

However, if Price_0=Price_1 then all measures =area E

Figure 18 - Schematic diagram of calculation of producer and consumer surplus

Wholesale market supply curve, SRMC and bidding

A challenge in establishing changes in consumer and producer surplus for additional wholesale market energy is that the supply curve in the NEM dispatch has positive, zero and negative cost bid elements (Figure 19):

Positive bidding technologies are recovering fuel and operating and maintenance costs and this is well aligned with the concept of SRMC.

Zero bidding elements include variable renewables such as wind and solar photovoltaics, which have limited control over their output and zero fuel costs, and accordingly would nearly always benefit from providing energy so long as the market price is zero or greater.

If the market price were zero too often, variable renewables would eventually need to increase their bid to recover some operating and maintenance costs so near-zero is a more accurate representation of renewables SRMC over multiple periods than their bids.

Negative supply bidding technologies mainly include coal-fired power which, due to minimum-run requirements (high shut down and restart costs), must make negative bids into the market for output below their minimum-run level to ensure their output can continue without suffering long-term impacts to the plant's operation. Like zero cost market bids from renewables, these negative cost bids from coal plants are not sustainable if they frequently set the market price, as such prices would not be sufficient to cover their true SRMC which includes fuel and operating and maintenance costs.

Our conclusion is that zero and negative bids represent genuine system costs that take into account the inconvenience to some technologies of shutting down. Minimum run constraints, for example, are a genuine technical constraint and is something that would be included in the ordinary course of conducting detailed electricity system modelling.

Despite some shorter term bidding behaviour not being reflective of SRMC over a longer time frame, we cannot ignore that when additional energy from DER enters the wholesale market, if it is from solar, it is likely to enter when the market is in a state of low operational demand because rooftop solar output is already high. As such zero and negative costs are relevant parts of the supply curve for the purposes of calculating changes in consumer and producer surplus. However, it will not always be the case that this will be the price setting part of the supply curve and will depend on the region, season and other daily characteristics such as public holiday and weekend/weekday status.

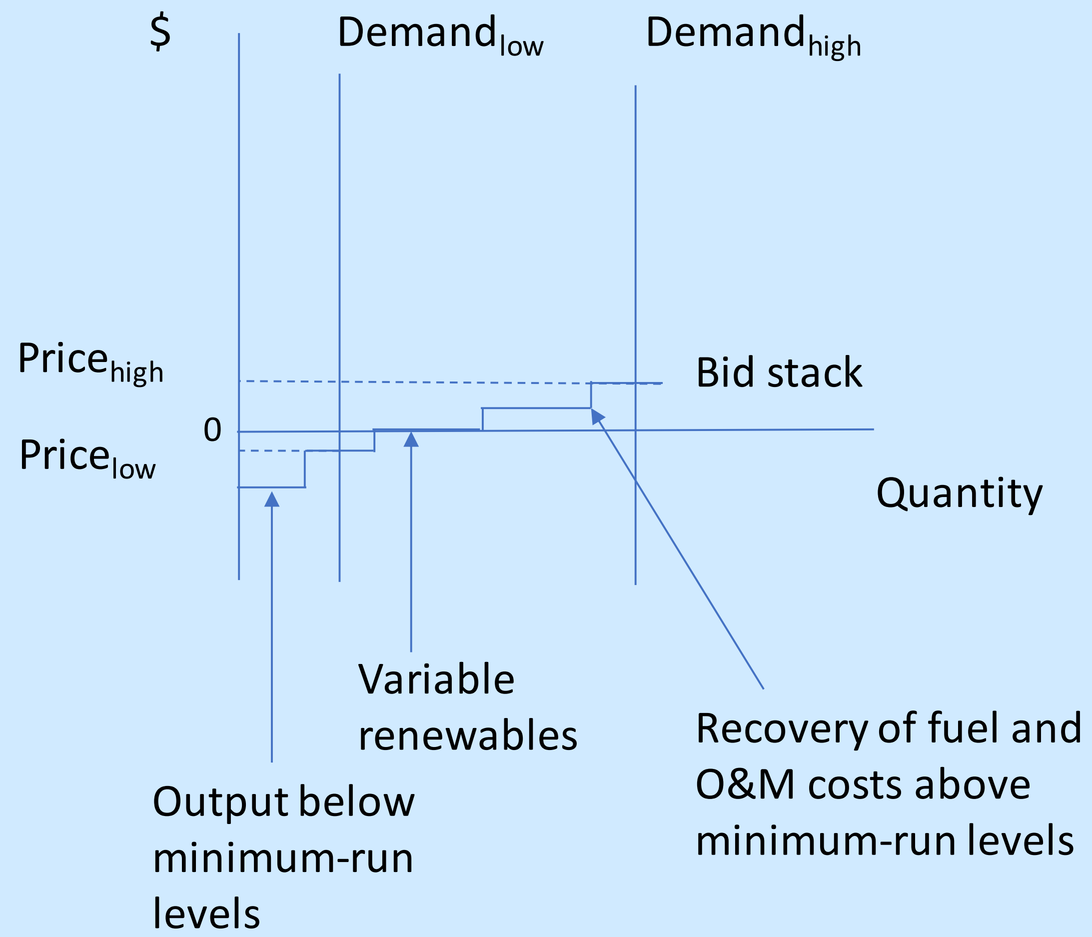


Figure 19 - Schematic diagram of the negative, zero and positive components of a bid stack and their sources

Appendix F Method formulas and worked examples

Overview

In this section we outline the equation for calculating each benefit and provide worked examples to demonstrate how to calculate each service using each appropriate method. Table 16 restates selected services and methods detailed in the previous section and adds the specific worked DER examples explored and summarises the net present values determined in this section. The range in values determined reflects differences in NEM states.

Table 16 – Summary of values determined in worked examples shorthand method implementation

Service	Method	Example	Unit value in 2020	Net Present Value of benefit 2020
Variable energy	Generation total cost	Expanded rooftop solar export cap 5 to 10kW	\$13-20/MWh	\$100,000-\$153,000/MW[1]
	Generation running cost	Avoided tripped rooftop solar	\$11-49/MWh	\$41,000-\$175,000/MW
Flexible energy	Generation running cost	EV charging shifted	\$5-\$90/vehicle	\$5-\$90/vehicle[2]
Combined variable and flexible energy services	Generation total cost	Rooftop solar and battery VPP export cap expanded 5 to 10kW	No benefit found for systems not in BAU \$96 -119/MWh for BAU systems	\$350,000-\$1,119,000/MW
Flexible capacity	Generation total cost	Existing large battery or V2G export cap expanded 5 to 10kW	\$828,000/MW[3]	Not calculated[3]
Environmental services	Environmental price method	All additional rooftop solar	\$2-16/MWh	\$5,000-\$36,000/MW

[1] Up to $100,000 per MW in Victoria for a more modest 7kW export cap.
[2] The flexible energy example was a one-year project only.
[3] The example is not expected to be relevant until deployment of vehicle to grid capable electric vehicles and so present value is currently not relevant. Unit value is for 2030.

Provides variable energy

An example of this type of service is when networks increase network hosting capacity to allow additional rooftop solar production, reducing frequency of events where voltage increases result in inverter trips during high customer export periods in high rooftop solar adoption areas.

Generation total cost method: formula for variable energy

This benefit method is applicable when the additional DER energy is available over an extended period, is demonstrably needed by the sector in that generation region based on future planning and the annual energy profile is a strong enough substitute for the standard solution to be avoided or reduced. Any existing DER capacity under the business as usual is free to the system. However, if the investment in hosting capacity induces additional investment in DER capacity, these costs are subtracted from the benefit of the additional DER output (which is avoided investment in large scale generation capacity).

If no new DER capacity is induced relative to the business as usual the formula for the implementation of this method is:

$$NetPresentValueofAdditionalDER = \sum_{t=1}^{T}\left[\frac{1}{(1+DiscountRate)^{t-1}} \times AdditionalDEROutput_t \times \frac{TotalCostStandardGenerationSolution}{AverageTransmissionLossRate}\right]$$

If new DER capacity is induced relative to the business as usual the formula for the implementation of this method is:

$$NetPresentValueofAdditionalDER = \sum_{t=1}^{T}\left[\frac{1}{(1+DiscountRate)^{t-1}} \times AdditionalDEROutput_t \times \left(\frac{TotalCostStandardGenerationSolution}{AverageTransmissionLossRate} - TotalCostAdditionalDERCapacity\right)\right]$$

TotalCostStandardGenerationSolution is in dollars per megawatt hour (MWh)and will change over time with changes in technology costs. The *AverageTransmissionLossRate* is assumed to be constant over time but could be varied if there were projected changes available

The set t=1,…….T is time in annual steps up to T which is the whole period the additional DER is enabled.

The formula for both *TotalCostStandardGeneration* and *TotalCostAdditionalDERCapacity* is:

$$TotalCost_t = AnnualisedCapitalCost_t + AnnualisedOperating\&MaintenanceCost + FuelCost_t$$

Where,

$$AnnualisedCapitalCost_t = \frac{(1 + Discountrate)^{ConstructionPeriod} \times CapitalCost_t}{AnnualCapacityFactor \times 8760} \times \frac{Discountrate \times (1 + DiscountRate)^{economiclife}}{[(1 + DiscountRate)^{economiclife} - 1]} +$$

Where *CapitalCost* is in dollars per megawatt (MW) and the first term immediately before that is simplified way of accounting for interest lost during construction. This can be modified for construction projects longer than a year where the initial capital drawn down may occur over several years.

8760 is hours in a year.$AnnualisedOperating\&MaintenanceCost = VariableOpertaing\&MaintenanceCosts + \frac{FixedOperating\&MaintenanceCost}{AnnualCapacityFactor \times 8760}$

Where *VariableOperatingCost* is in dollars per MWh and *FixedOperating&MaintenanceCost* is in dollars per MW.

Input fuel costs, where they apply, are converted from input costs in dollars per gigajoule to a common energy standard of dollars per megawatt hour as follows:

$$FuelCost_t = \frac{\$}{GJ} \times \frac{3.6}{FuelEfficiency}$$

Generation total cost method: worked example – static 5kW export limit increased to static 10kW limit

In this case we assume the network has invested in infrastructure or information services that provide increased visibility allowing them to selectively increase the export limits for customers in unconstrained areas from 5kW to 10kW year-round (i.e. a static setting). This could also be done dynamically, which is being explored by networks, but the data for dynamic export limits was not readily available to apply here so we use a static example.[61]

We find that large-scale solar PV is the relevant wholesale generation standard solution. Other services such as meeting environmental requirements in Victoria and Queensland are not directly addressed here but we return to environmental services in examples below. Indirectly we take account of the additional value Commonwealth and state governments place on rooftop solar through available subsidies. This is appropriate because the method should not try to undo government policy decisions to intervene in markets to place higher value on some types of investments.

[61] Were such data available, the same methodology choices apply. The profile should be examined to determine whether it avoids large-scale investment because it has a similar profile to large scale technologies or whether it avoids running costs. While there is no data available, our expectation is that the profile would be narrower and flatter than a static change in export limits because the rooftop solar would only be able to access the extra export capacity less frequently. There might also be less additional investment above the business as usual for the same reason. This may support using the running cost method.

For now, we exclude potential changes to battery ownership, size and operation but will return to this as a combined service in later examples.

Networks will calculate their own expected additional DER output profiles from studying their networks. For the purposes of presenting a worked example, we ran a simulation of customer's preferred rooftop solar system sizes in each state with 5kW and 10kW export connections. A sample of the resulting exports under the two limits is shown in Figure 20.

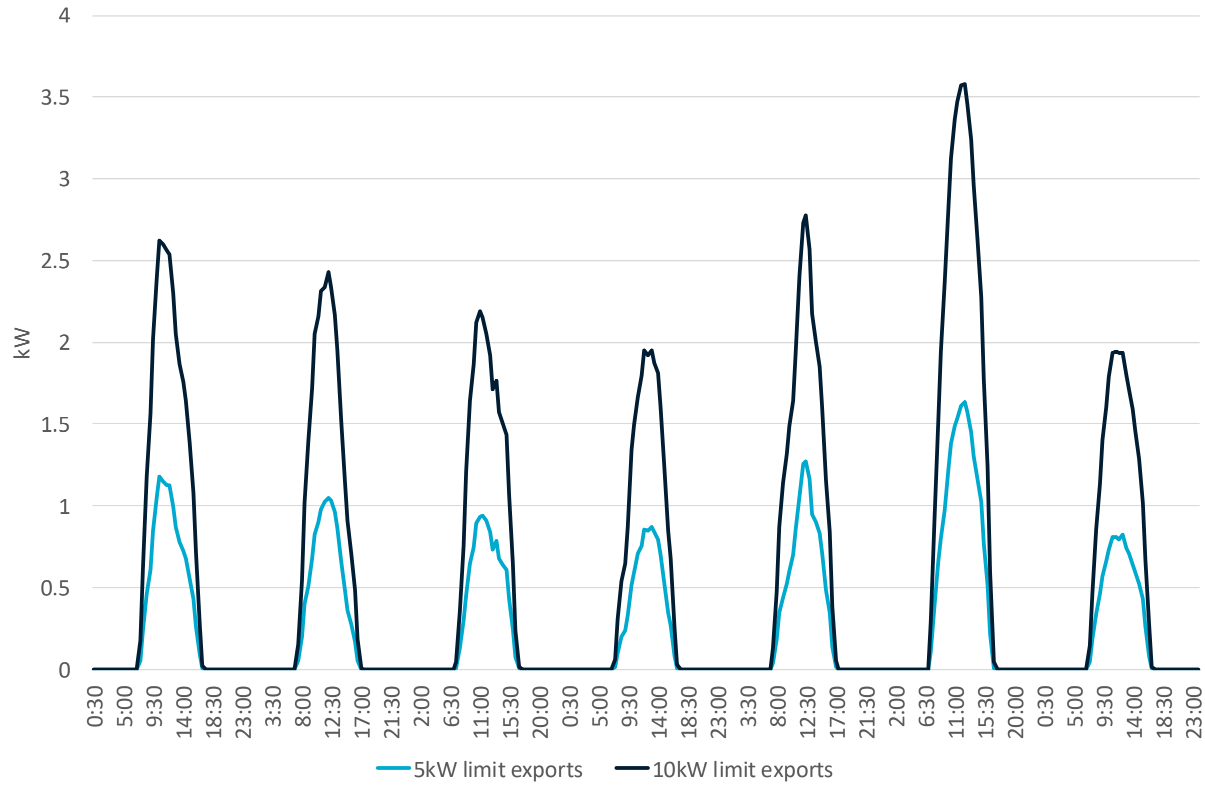


Figure 20 - Smaple of after-diversity rooftop solar exports under alternative export limits

If we compare the capacity factor of the additional DER exports (which is the difference between the two profiles) to large-scale solar the ratio is 0.71 to 0.76 across the NEM regions and so is a good candidate to substitute for large-scale solar investment. This is also evident from a visual comparison of their average daily outputs shown in Figure 21.

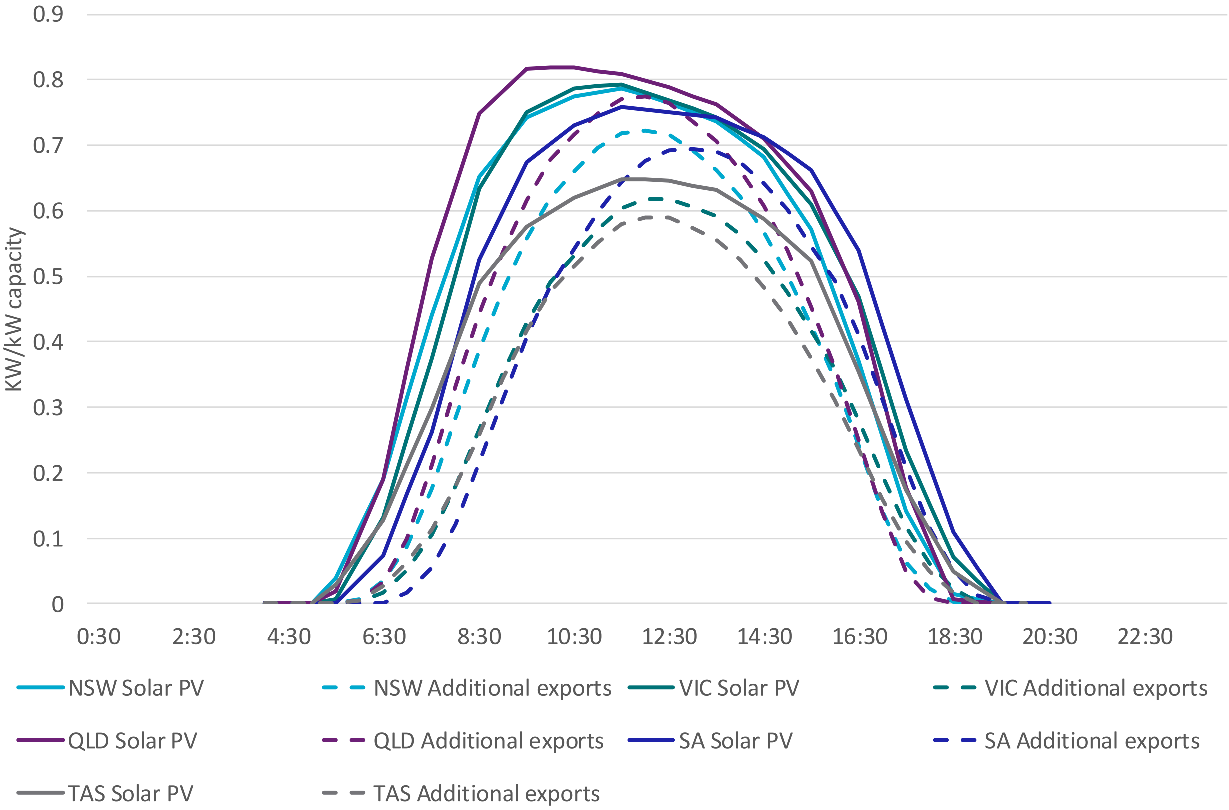


Figure 21 - Comparison of additional rooftop solar and large-scale solar average daily generation profiles (normalised)

Our own bill minimisation analysis and general industry trends of growing system sizes indicate that customers would build larger rooftop solar systems, relative to business as usual, if they are aware that 10kW export limits are available. Where we include wholesale market benefits for additional DER investment above business as usual, we must also include the costs. Any additional benefits from business as usual systems are without cost (apart from whatever investment was required to deliver the expanded export cap which is out of scope)

Rooftop solar is slightly lower in capital cost relative to large-scale solar, reflecting extra costing for mounting panels and tracking the sun (shown in Figure 22 and based on GenCost 2019-20 data in Graham et al., 2020). Available subsidies from the federal government are from the small-scale renewable energy target and are referred to as small-scale technology certificates (shown in Figure 23). Victoria has its own $1888 subsidy for eligible systems (which may be available until around 2030[62]). Given this is a flat level, not attached to a system size, the subsidy on a per kilowatt basis is lower the larger the system installed. The Victorian subsidy for a 10 kW system is $189/kW, $270/kW for a 7 kW system and $378/kW for a 5kW system.

Despite the lower capital cost and subsidies available, the capacity factor for rooftop solar is around 50-55% that of large-scale solar resulting in a cost disadvantage in delivered energy terms. Adjusting for avoided transmission losses, the net benefit per MWh of energy over time from rooftop solar (that was not in the business as usual) compared to large scale solar is positive

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[62] The subsidy may decline but we do not include that due to lack of data.

initially but falls and is negative in the long run. Two rooftop system sizes are shown for Victoria (Figure 24). The data indicates that rooftop solar capacity above the business as usual has a limited window to provide positive project benefits under current or future projected costs.

To calculate the net benefits, we need to make a projection about how much of the DER that is using the additional export capacity is in the business as usual and how much is new. A detailed projection is out of scope. We assume a 30% existing to 70% new ratio which is roughly aligned with growth in rooftop solar in AEMO's High DER scenario between 2020 and 2040.

Commencing in 2020 and lasting 20 years, based on the calculated value per MWh for 10kW systems, the net present value of a MW of additional rooftop solar capacity (some existing in BAU, some new) is $100,000 to $153,000 across the states[63]. However, this value falls by 75% within 5 years. By 2031 all states would find negative project benefits. Because it has a subsidy independent of project size, if Victorian export capacity was only increased to 7kW, the subsidy per kW would be higher. Subsequently the, the net present value of the benefits of additional rooftop solar in 2020 is more positive at $184,000/MW.

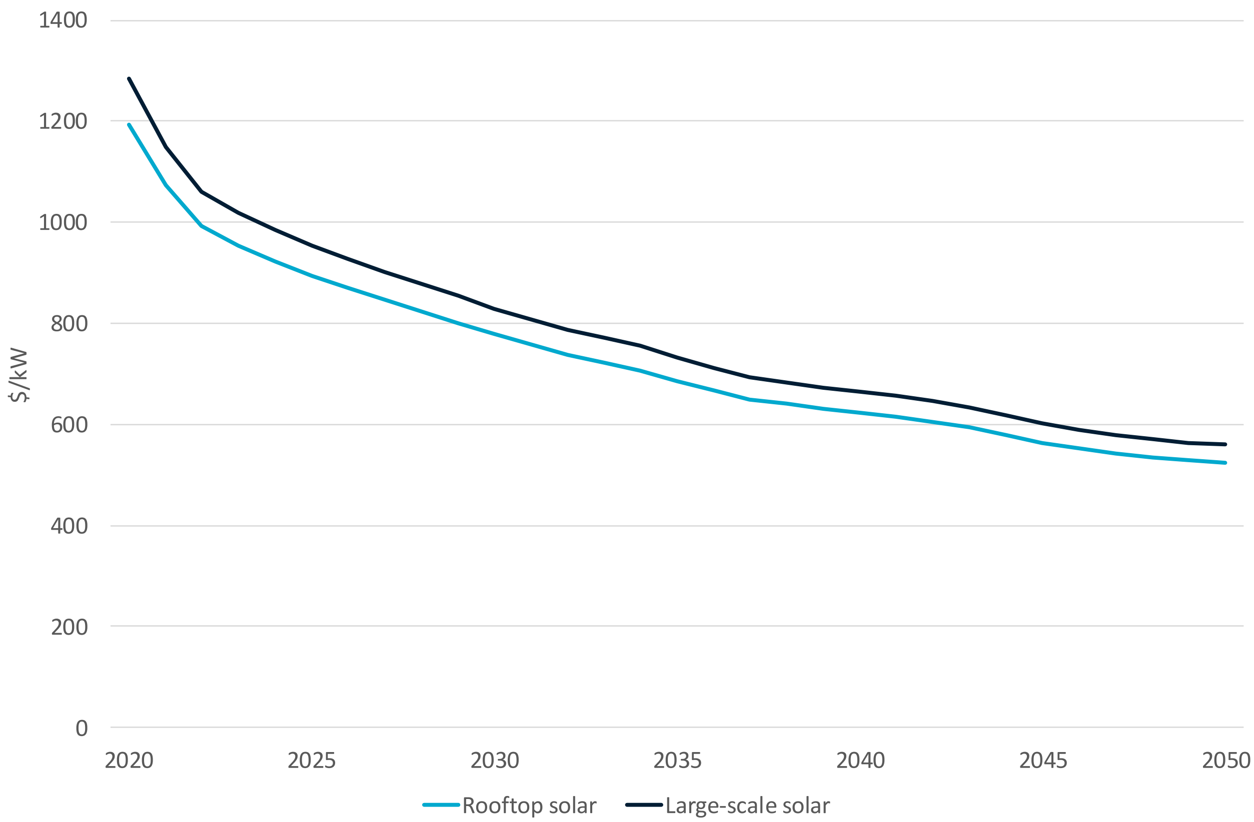


Figure 22 - Rooftop solar and large-scale capital costs

[63] This has been calculated by scaling up the additional exported solar profile so that it has a peak capacity of 1 MW and multiplying by the value per MWh.

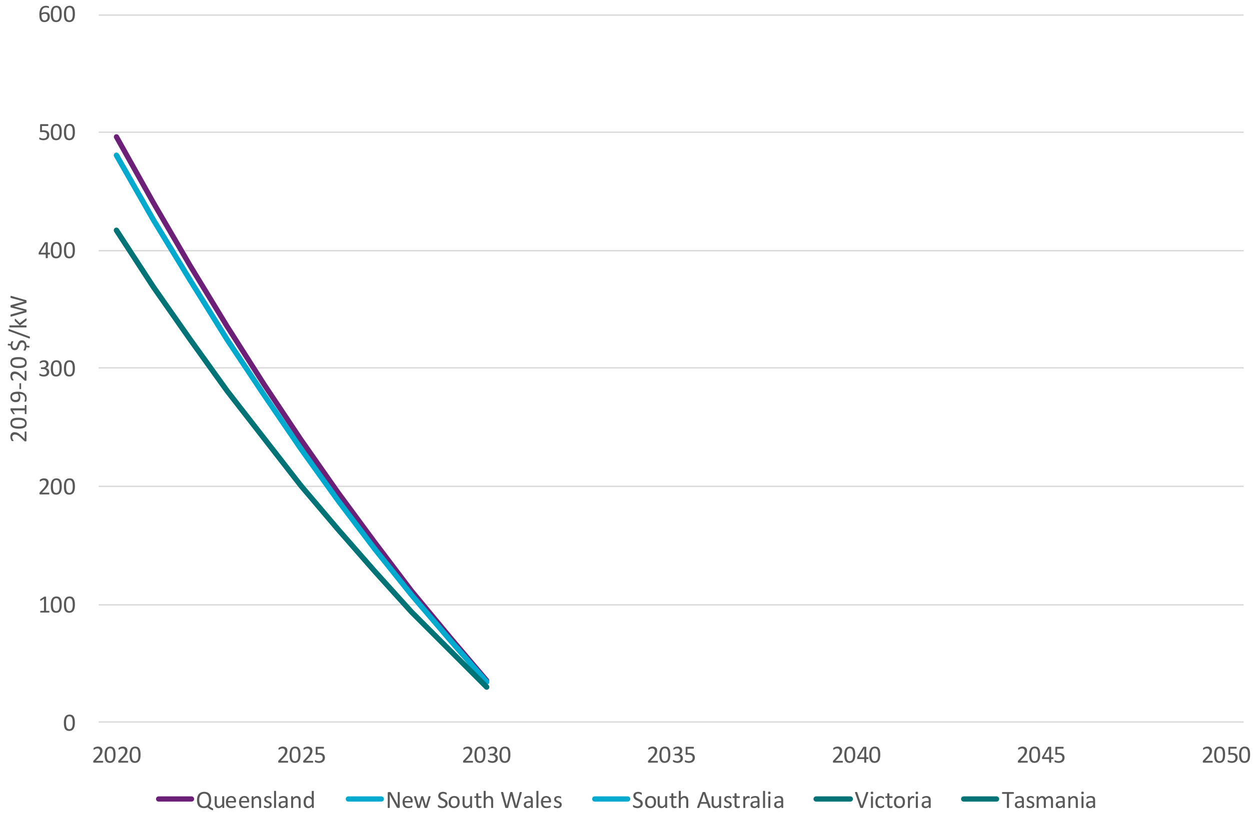


Figure 23 - Commonwealth rooftop solar subsidies (small-scale technology certificates)

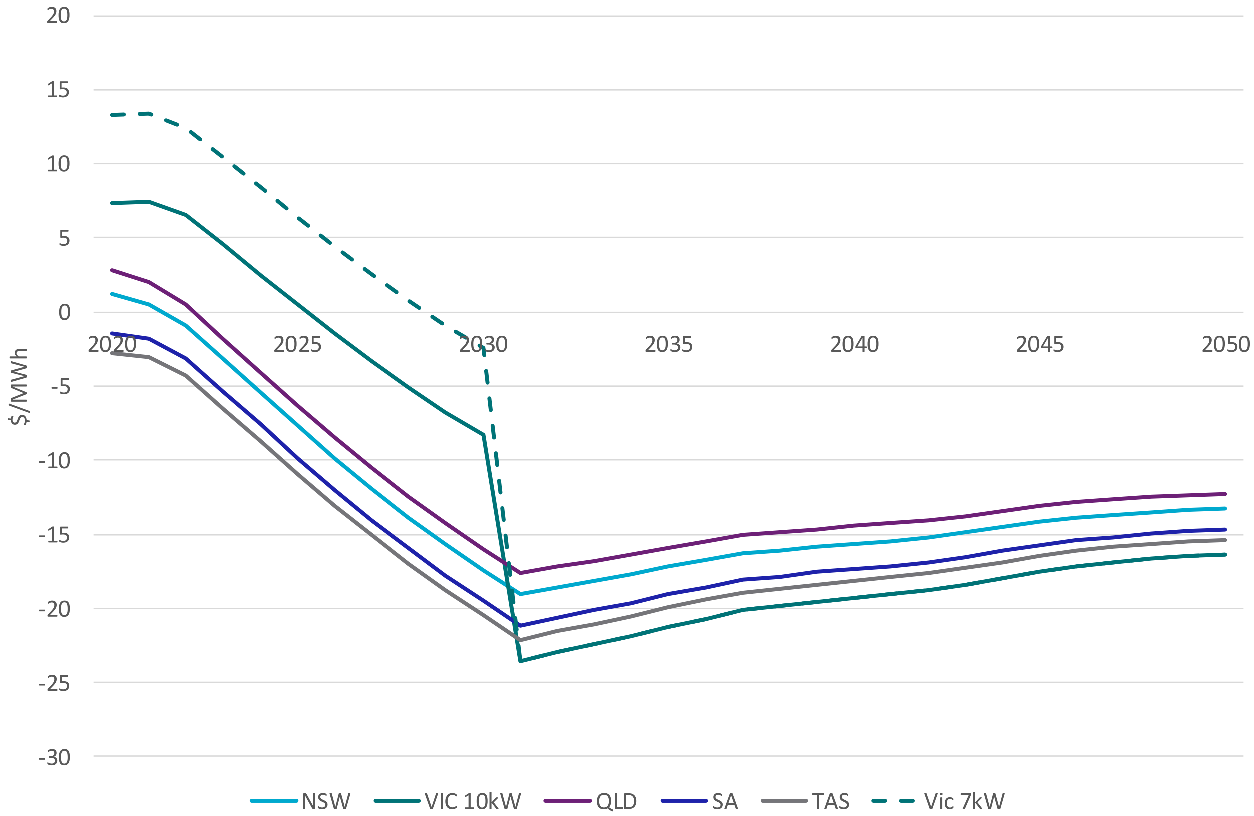


Figure 24 - Benefit per MWh over time of additional rooftop solar

Generation running cost method: variable energy

This benefit method is applicable when the additional DER energy is not demonstrably needed by the sector in that generation region based on future planning and the annual energy profile is not a direct or strong enough substitute for the standard solution to be avoided or reduced. In these cases, the benefit is that the running costs of existing generation may be avoided. While data on the running costs of most generation capacity is available, we specifically need to calculate the running costs at the times when the additional DER energy is being provided to the wholesale generation market. This changes every five minutes and tracking this information is data intensive. To support a simpler shorthand method, wholesale market prices may be used as a substitute for running costs. See an extended justification for this approach in the Technical Concepts discussion in the previous section.

In fact, prices are more useful because they also capture the special cases (which are becoming more frequent) when the market is experiencing negative prices. Negative prices are a complex feature of the market, reflecting the need for some generation plant to continue to run during low demand periods. During these periods, some plants offer their generation at negative prices, and in some time periods these prices set the whole market price. Low demand periods are becoming more frequent with increased rooftop solar generation being one of the major causes. Adding additional rooftop solar generation through increased distribution network hosting capacity could increase the frequency of low or negative prices during the day. The generation running costs method for calculating benefits from additional DER takes this feature of the market into account.

The formula for the implementation of this method is:

$$PresentValueofAdditionalDER = \sum_{t=1}^{T}\left[\frac{1}{(1+DiscountRate)^{t-1}} \times \frac{\sum_{h=1}^{H}(Price_h \times AdditionaDEROutput_h) \times ChangeInPrices_t}{AverageTransmissionLossRate}\right]$$

Where,

The set t=1,…….T is time in annual steps up to T which is the whole period the additional DER is enabled

The set h=1,…….H is time in 30 minute steps up to H which is sourced from the most recent calendar or financial year of historical price data

Generation running cost method: worked example – static 5kW limit with tripping

The case of additional rooftop solar enabled through increased hosting capacity to reduce inverter tripping was selected as the worked example. In this case, large-scale solar PV was considered as a potential substitute, but the capacity factor ratio is 0.15 to 0.17 (also see Figure 26). The case of avoided investment is very weak and therefore a running cost method is appropriate. Other services such as meeting environmental requirements in Victoria and Queensland are ignored for now but returned to below.

Networks will calculate their own expected additional DER output profiles from studying their networks. For the purposes of presenting a worked example, we constructed a synthetic profile for additional rooftop solar that has been allowed by increasing hosting capacity – this is the solar generation that would have occurred if the inverter had not tripped due to voltage increases beyond the inverter's threshold. This was created by keeping all output from the normal rooftop solar profile during weekend and public holidays between 10am and 3pm and deleting output at all other times. This approach assumes most tripping of rooftop solar PV generation occurs on low demand days during high solar output. The export limit was 5kW. The business as usual tripped profile and the now avoided amount of tripped energy is shown together in Figure 25. This avoided tripped energy is also shown as normalised average daily generation profile in Figure 26 and compared to large scale solar PV average daily generation.

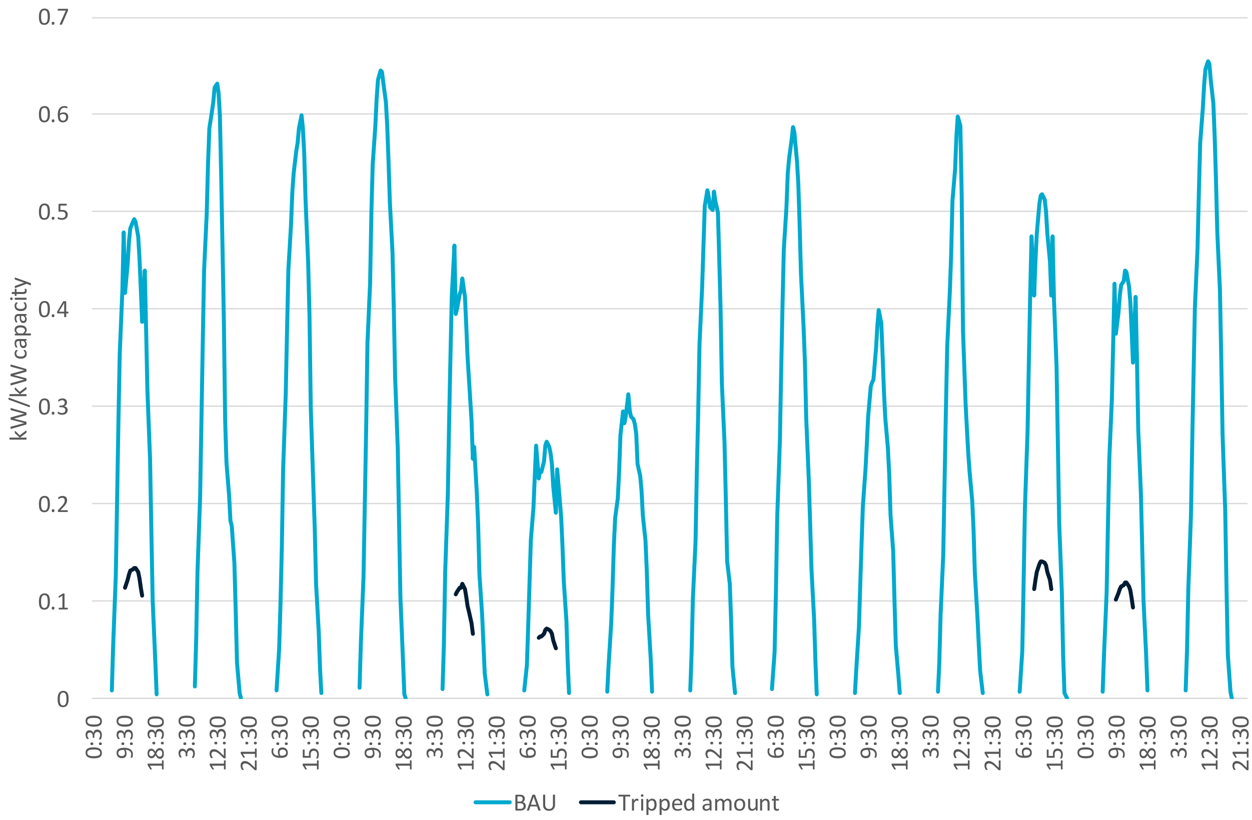


Figure 25 - Sample of synthetic profile of rooftop solar tripping under business as usual and tripped amount

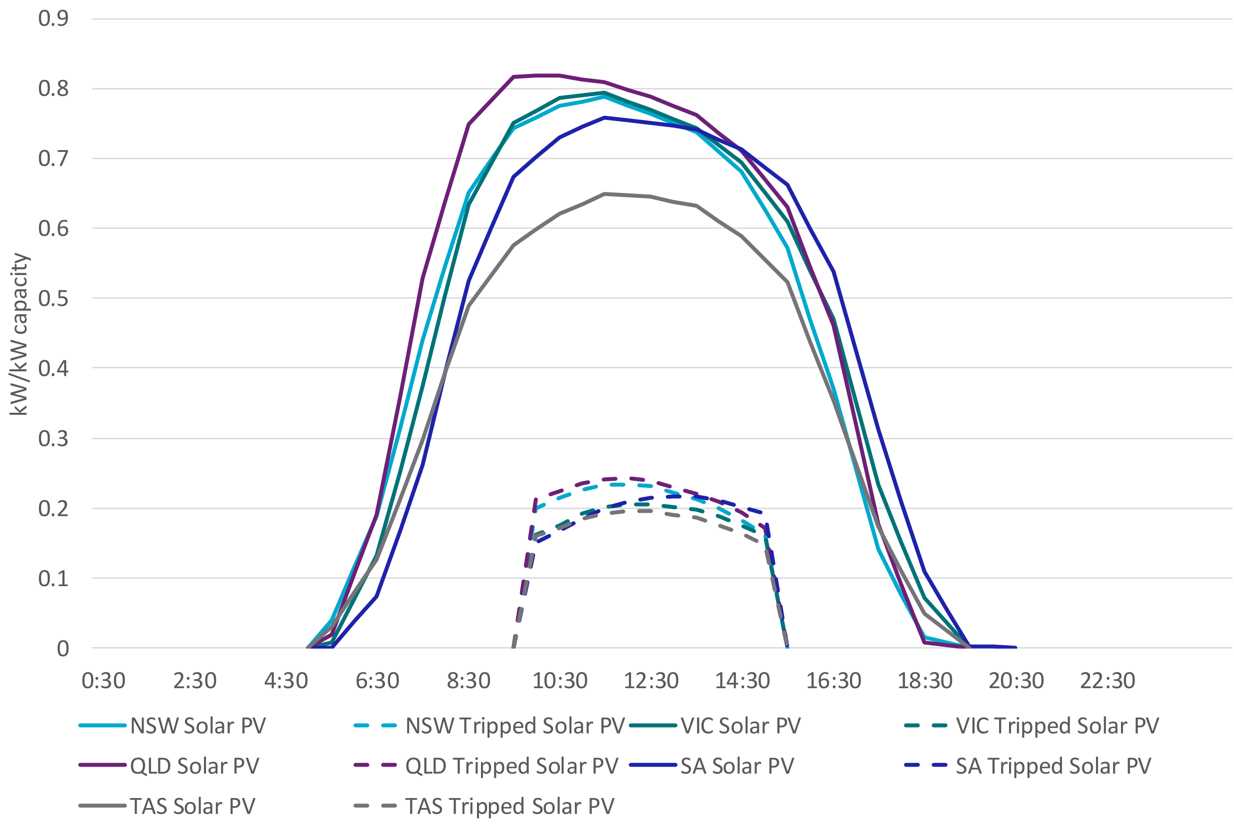


Figure 26 - Total cost of large-scale solar PV and value per MWh of additional rooftop solar PV under generation total cost method

To apply the generation running cost method, historical half hourly regional electricity prices have been collected for both calendar year 2019 and financial year 2019-20. Figure 27 shows the percent of times between 9am to 5pm that each of the regions experienced negative prices during these one-year periods. The relative prevalence of negative prices during the day reflects a combination of factors including increased deployment of rooftop and large-scale solar PV, low industrial demand in the region, the state of demand in neighbouring regions and more random factors such as the incidence of mild clear days on weekends and public holidays. The increase in negative prices in 2019-20 also reflects the one-off factor of reduced demand due to the imposed shutdown in economic activity to manage the COVID-19 pandemic.

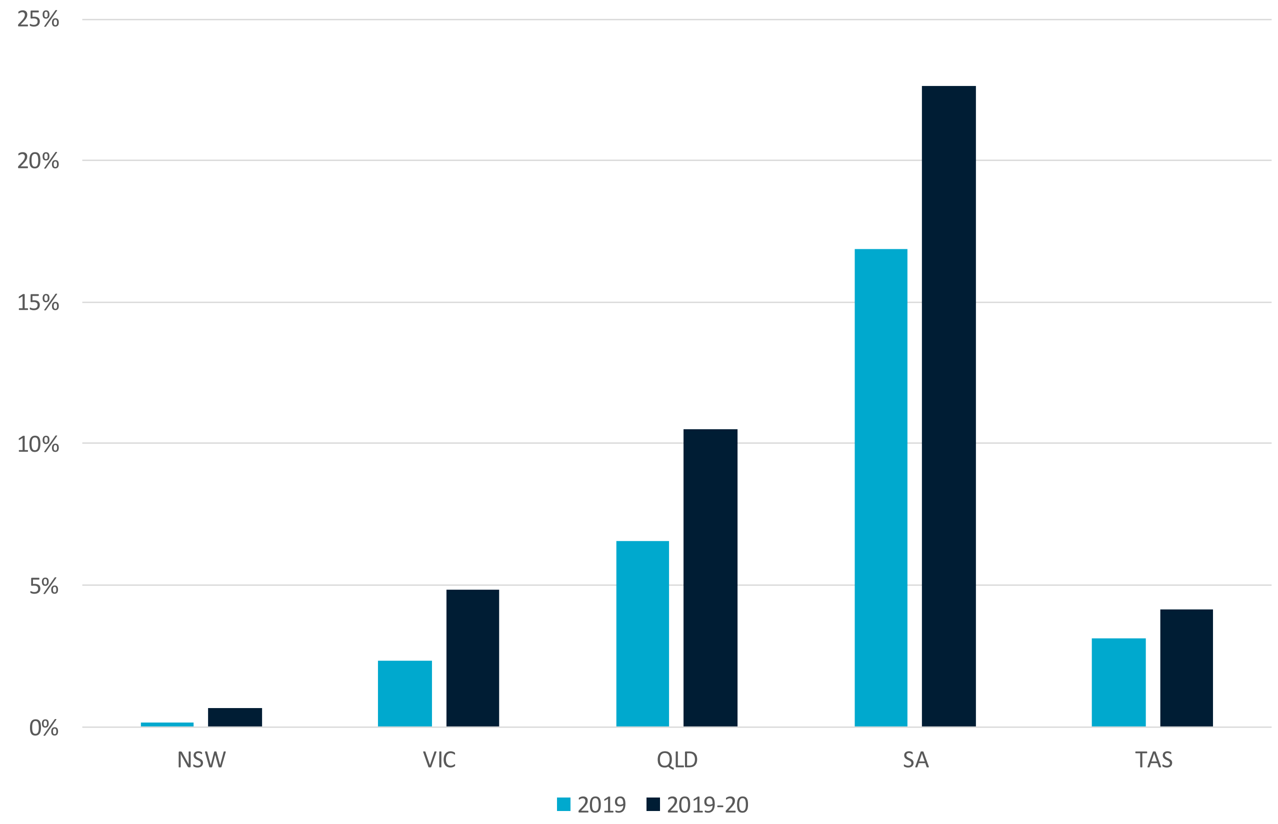


Figure 27 - Proportion of time region experienced negative 30-minute prices by region and period

The most recent historical half hourly prices are used in the formula as a starting point but must be adjusted over time to account for likely changes in average prices in the relevant time period. There are no regular half hourly or annual electricity price forecasts provided by AEMO or other groups. Should a source of this data emerge, it is the preferred source and we make a recommendation that the AER should consider publishing such data.

In the absence of half hourly price forecasts, a source that reflects changes in costs of electricity supply at the relevant time period should be used. For the trend in prices that would be received by rooftop solar PV, an index of the change in the total costs of large-scale solar should be used[64]. By setting the 2020 costs equal to one, the cost index by 2050 is 0.44. Our expectation is that the average value of all prices combined will fall overtime. Accordingly, the index is used as an annual adjustment factor (the $ChangeinPrices_t$ component of the formula above) of the summed value of half hourly prices in the first year. Applying this approach, the present value over 30 years of 1 MW of additional DER is $174,000 to $295,000 using historical 2019 calendar year prices as starting prices and $41,000 to $175,000 using historical 2019-20 prices as starting prices.

Values in 2019-20 are lowest due to an increase in negative prices (Figure 28) under lower demand associated with the economic impact of the COVID-19 pandemic. Queensland and South Australia are the lowest, reflecting their high rooftop solar uptake which accentuates lower demand by

[64] Large-scale solar is projected to be the most competitive supplier in this time period over the long run and so it is reasonable to expect volume-weighted prices during this period will converge towards the cost of large-scale solar. The index is applied directly to the volume-weighted average rather than the individual prices as it makes more sense in this context.

meeting a proportion of demand through generation at the site of consumption rather than through the grid. These states also have growing large-scale solar generation.

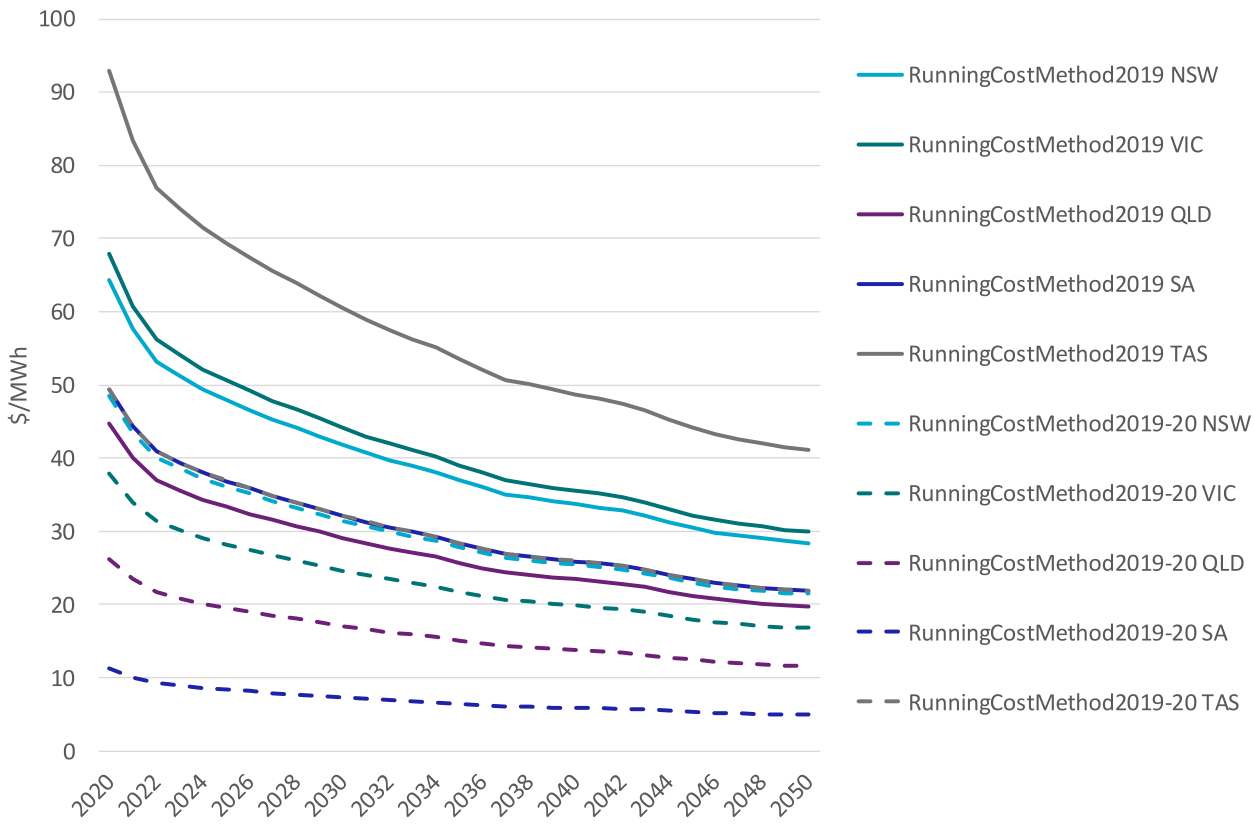


Figure 28 - Average value of avoided running costs to 2050 for starting years 2019 and 2019-20

Provides flexible energy

The previous example focussed on networks increasing hosting capacity to expand the amount of rooftop solar that can be generated and exported. This additional rooftop solar was still weather dependent and inflexible. However, networks may be able to increase hosting capacity by incentivising additional energy at different times of the day. This may result in no additional energy but may have value in the sense of shifting DER energy from low value to high value times. Some examples might include:

- Networks incentivising batteries for rooftop solar owners
- Networks incentivising off-peak electric vehicle charging
- Networks incentivising off-peak pool and spa pump operation

Specialised network tariffs might be one way in which incentives are provided.

Generation running cost method: flexible energy

Given that flexible energy is too difficult to define against any specific large-sale technology, the generation running cost method is appropriate so long as we adjust for potential changes in the value of flexible energy. As previously discussed, market prices are used as a proxy for avoided fuel and operating costs. Prices have the advantage of capturing negative price periods, which are becoming more frequent in some regions and are a complex component of the running costs of generation that is not easily shut down and restarted.

The formula for the implementation of this method to calculate the net present value of additional flexible DER energy is similar to the formula for variable energy:

$$PresentValueofAdditionalDER = \sum_{t=1}^{T}\left[\frac{1}{(1+DiscountRate)^{t-1}} \times \frac{\sum_{h=1}^{H}(Price_h \times AdditionaDEROutput_h)}{AverageTransmissionLossRate}\right]$$

Where,

The set t=1,…….T is time in annual steps up to T which is the whole period the additional DER is enabled.

The set h=1,…….H is time in 30 minute steps up to H which is sourced from the most recent calendar or financial year of historical price data.

The primary difference between the approaches is that for flexible energy, since there is no direct substitute, we make no assumption about changes in prices, and remove the *ChangeinPrices* variable from the formula. Flexible energy is inherently more valuable and will likely hold its value over time absent significant changes.

Generation running cost method: worked example

For this worked example we assume a network has incentivised through a tariff a change in load to encourage daytime electric vehicle charging. This could also have the impact of reducing tripping, which was the outcome in the previous example and this outcome could be added as a benefit if that was the case. The load shifting might also avoid network capacity which could also be added, but we deal with that benefit separately further below. We focus here only on the impact of the load shifting on the generation sector.

We use a synthetic profile of load shifting created by comparing two electric vehicle charging profiles. The first, which is the counterfactual or BAU profile, is a convenience profile that would likely occur if there is no incentive to avoid peak times (e.g. under a flat tariff). The second is a charge profile that has been modified so that most charging occurs during solar generation times with some allowance for the need to occasionally charge outside these times[65]. The difference between these two profiles is the shifted load; its value depends on the degree to which the avoided running costs when it reduced charging are greater than the running costs when charging was increased. The average charging profile – based on a medium size passenger vehicle -- per day is shown in Figure 29. The profile shown is for NSW, but a separate profile is used for each state accounting for that region's average driving distance. The profile is assumed to have shifted due to an annually applied incentive reflecting time of day and is not responding to daily dynamic wholesale price signals (we include an example where a battery is responding to wholesale price signals further below).

[65] These profiles were originally developed by Graham et al (2019) but are also published in the AEMO ISP input and assumptions workbook.

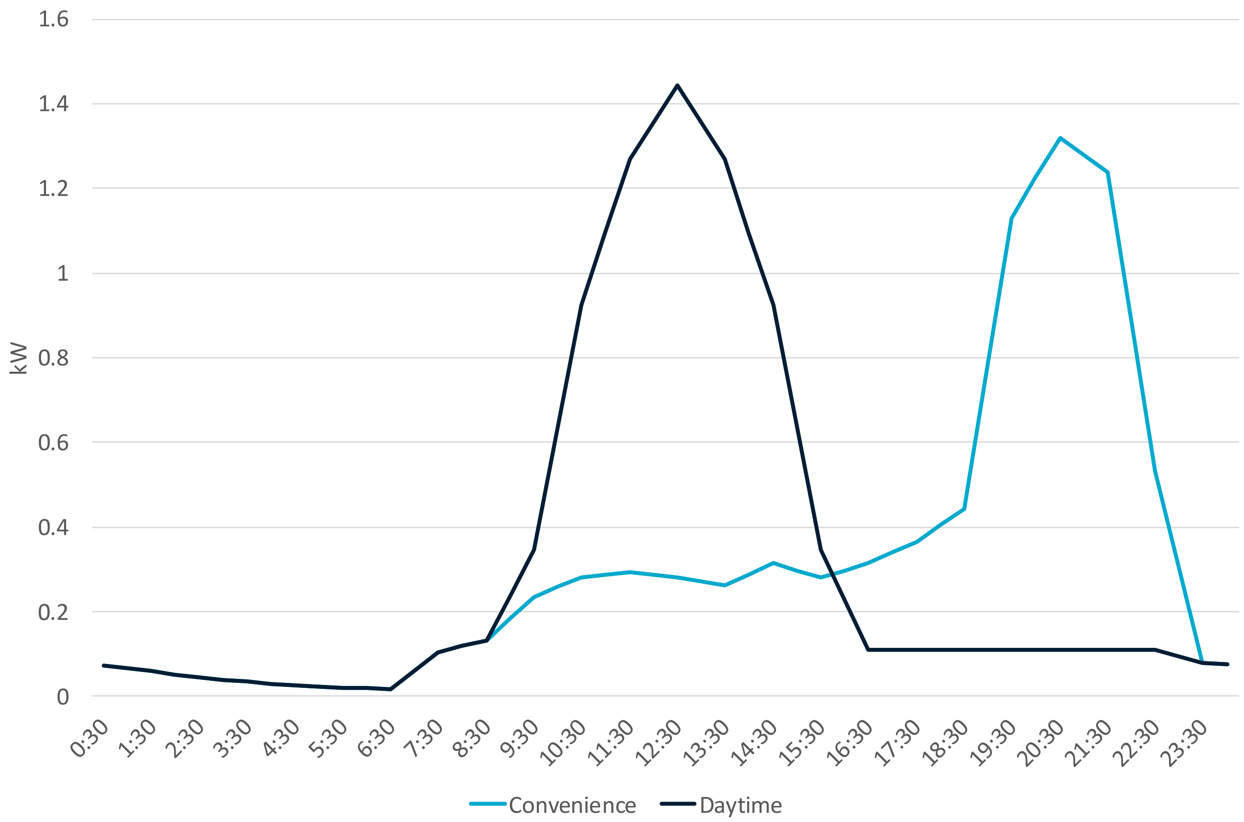


Figure 29 - Convenience (flat tariff) and incentivised daytime electric vehicle charging profile for NSW medium passenger vehicle

Figure 30 shows the 2019-20 annual value per vehicle of flexible energy from shifting the load profile of electric vehicles. An annual value is used in this example because we assume a customer has signed up to an incentive to shift load for one year[66]. Not surprisingly the value is greatest in South Australia where daytime prices are negative for the highest proportion of the year, increasing the value of shifting load into the day.

This example could be modified beyond an annual incentive. More dynamic daily control and pricing incentives applied to electric vehicles would likely yield higher value per vehicle because responses would be better aligned to daily real time price signals. For example, on a low solar generation day, it might not be preferred that all vehicles concentrate their charging on the few hours around midday. There might also be an opportunity to avoid charging in the rare very high-priced periods (i.e. near the market price cap) that occur each year (which might not otherwise be avoided under a simple annual price signal). However, with more dynamic control would come extra costs (e.g. communication infrastructure) to achieve that outcome. Networks would need to consider those trade-offs in designing their project.

[66] In the formula, T=1 and the discount factor is essentially removed from the equation.

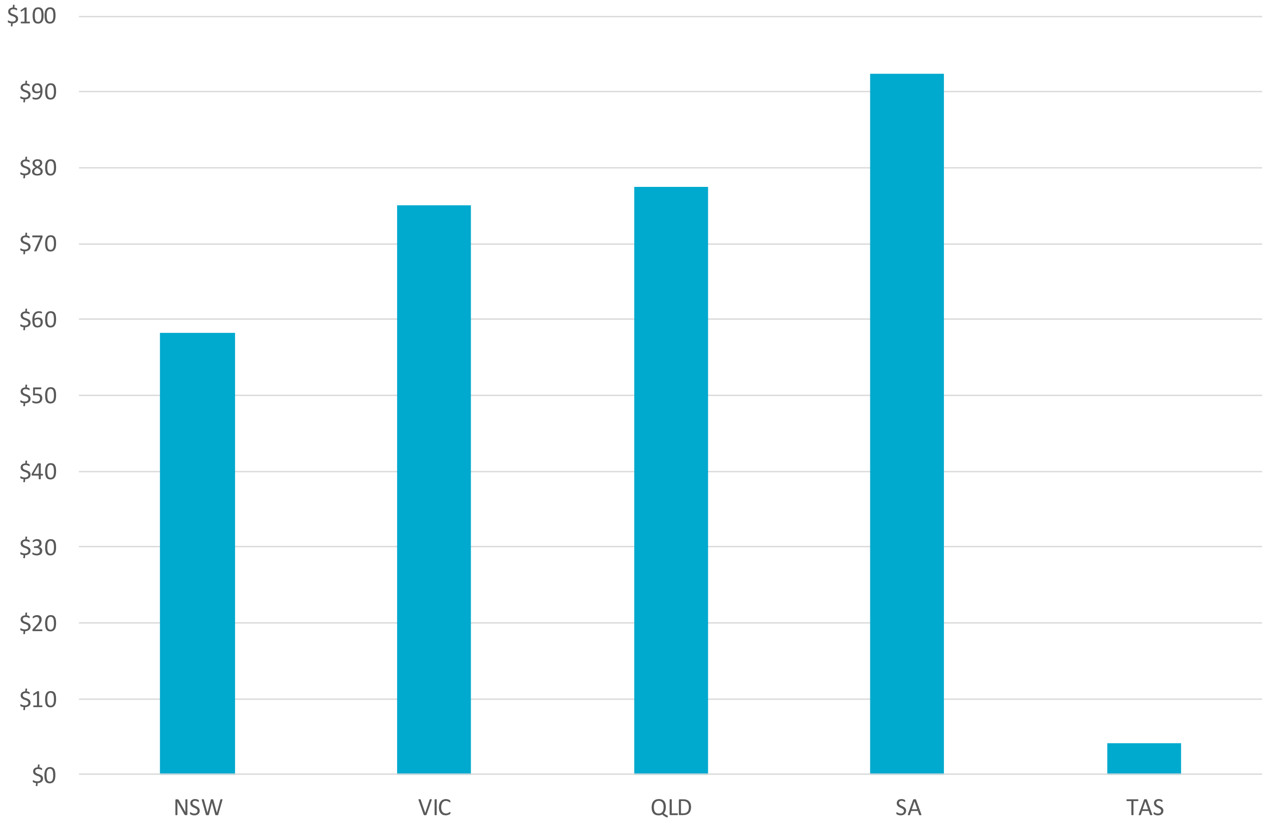


Figure 30 - The annual value per vehicle of flexible energy from electric vehicle load shifting

Provides flexible capacity

This method applies where additional flexible DER capacity is made available for capacity services. Capacity services do involve providing energy, but that energy is generally of low value relative to the capacity which is on standby to address short term needs such as reliability, frequency control and ancillary services.

Generation capacity method: flexible capacity

The method for valuing additional flexible DER capacity in the generation sector is to calculate the amount of additional capacity available to the generation sector and multiply it by the annualised value of the closest large-scale capacity substitute with similar technical properties. The value is summed and discounted over the life of the capacity availability. The cost of any new DER capacity above business as usual which is induced by the hosting capacity investment, is included as a cost. The formula is as follows:

$$PresentValueofAdditionalDER = \sum_{t=1}^{T}\Bigg[\frac{1}{(1+DiscountRate)^{t-1}} \times \Big(AdditionalDERCapacity_t \times AnnualisedCapitalCostSubstitute + DERCapacityInvestmentAboveBAU_t \times (AnnualisedCapitalCostSubstitute - AnnualisedCapitalCostDER)\Big)\Bigg]$$

Where,

The set t=1,…….T is time in annual steps up to T which is the whole period the additional DER is enabled. The *AnnualisedCapitalCostSubstitute* and *AnnualisedCapitalcostDER* are calculated as:

$$AnnualisedCapitalCost = CapitalCost \times \frac{Discountrate \times (1 + DiscountRate)^{economiclife}}{[(1 + DiscountRate)^{economiclife} - 1]}$$

This annualised capital cost formula refers to generation sector capital and differs from that previously used in the generation total cost method because the units here are $/MW (a capacity value), whereas additional terms in the other formula converted costs to $/MWh (an energy value).

A worked example is not provided for this method. A possible case though might be where existing batteries are enabled to participate in FCAS markets and there are limited other impacts or changes to investment and behaviour. However, if the enablement of this FCAS market participation also allows participation in other markets or impacts choices around the size and operation of batteries and rooftop solar, then a combined energy and capacity services approach is required.

Network capacity method: flexible capacity

The method for valuing additional flexible DER capacity in the network sector is to calculate the amount of additional capacity available to the network sector and multiply it by the annualised value of a network capacity substitute. In contrast to the generation capacity method, the technical property of the capacity in the network sector has fewer requirements and ways of meeting capacity demand with conventional "poles and wire" capital being dominant. Consequently, the additional DER capacity need only reach the threshold of avoiding or deferring network capacity – the exact combination of other properties of the DER capacity, such as ramping rate, are not as important if that threshold is met.

The value is summed and discounted over the time period that network capacity is avoided or deferred. As such the formula does not change from the generation capacity method, only the type of capital substituted by the additional DER capacity. No worked example is provided for this method. As in the generation sector, batteries may be a good example but are often difficult to entirely separate from their interaction with rooftop solar which we now address.

Provides a combination of energy and capacity services

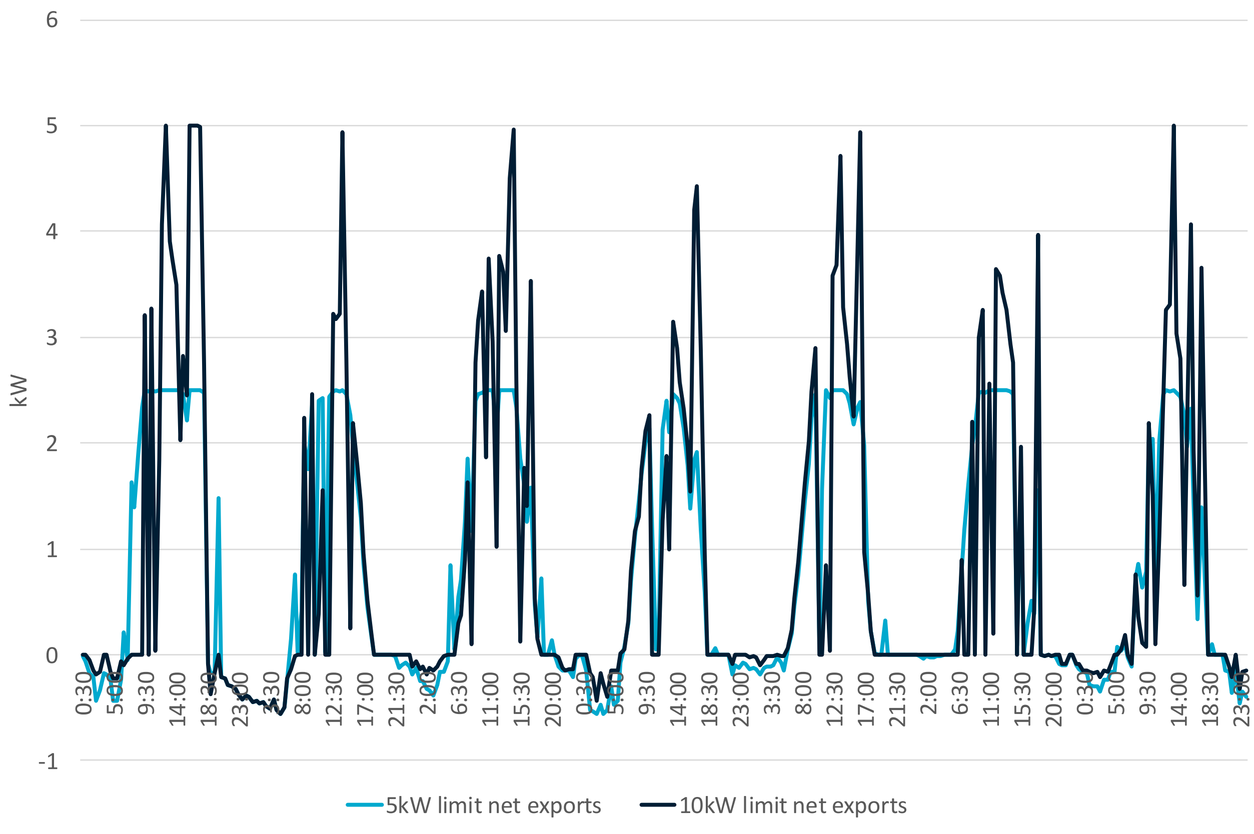
This method applies to situations where increased DER hosting capacity leads to changes in investment and operation of both DER energy and capacity. A likely common example is where increased hosting capacity leads to additional rooftop solar and battery outputs. There is no change to the previously described formulas for energy and capacity services, except that instead of a single technology substitute in the generation total cost method the substitute is a combination of large-scale technology costs. For the generation running cost method the generation profile to be applied to prices is the profile of the combined DER technologies.

Generation total cost method applied to combined energy and capacity services: worked example – static 5 kW export limits converted to static 10 kW limits for VPPs

While not necessary for the implementation of the total generation cost formula, we calculated the profile for the BAU 5kW and 10kW limited rooftop solar battery hosting capacity investment case using optimisation. These are static controls export limits because we do not have access to data on dynamic limits.[67]

A sample of the net export profiles under the two static limits is shown in Figure 31. The optimisation resulted in the selection of larger solar and battery systems to make use of the additional export capacity. This means that we are likely to see some customers choose to invest in larger systems than they would have in the business as usual.

The difference between the 5kW and 10kW export limit battery profiles is the total impact on the generation sector and is shown in Figure 32. It shows that with an additional 5kW export capacity, batteries in all states would increase their exports during the morning and evening peaks when wholesale prices are higher (with the exception of Tasmania where prices appear to be more attractive during daytime). It can also be said that states generally increase exports throughout the day except in NSW and Victoria where there appears to be an advantage in reducing exports in the middle of the day, perhaps to have more battery charge available for higher priced periods prices outside this time.



[67] Were such data available, the same methodology choices apply. The profile should be examined to determine whether it avoids large-scale investment because it has a similar profile to large scale technologies or whether it avoids running costs. While there is no data available, our expectation is that the profile would be narrower and flatter than a static change in export limits because the rooftop solar would only be able to access the extra export capacity less frequently. There might also be less additional investment above the business as usual for the same reason. This may support using the running cost method.

Figure 31 - Comparison of BAU 5kW limit and increased hosting capacity enabled 10kW limit VPP sample net export profiles, NSW

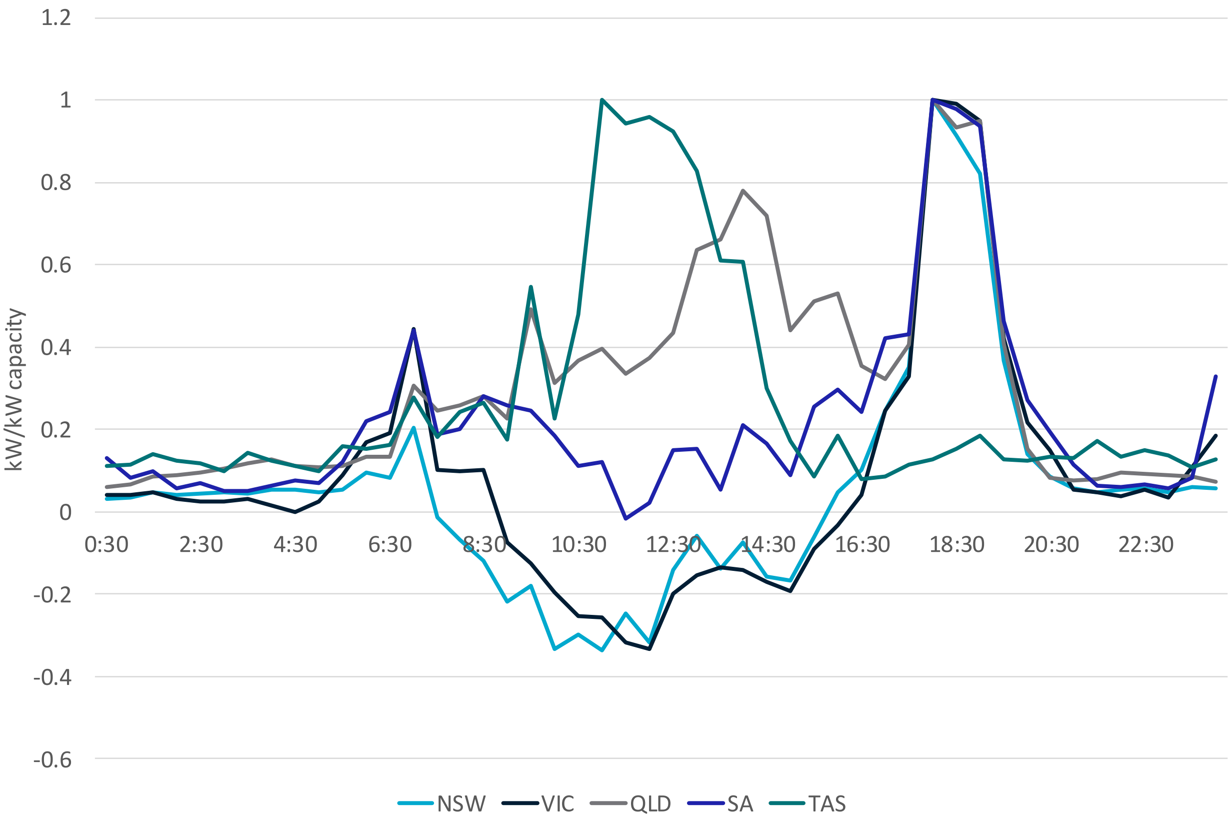


Figure 32 - Average daily profile of difference in net export profile of BAU 5kW limit and increased hosting capacity enabled 10kW limit VPP

The most appropriate large-scale generation technologies to provide a substitute value for this additional DER is large-scale solar with large-scale batteries of around 2 hours duration. Figure 33 compares the total cost of rooftop solar with batteries and large-scale solar with batteries. While in the case of solar only, it was possible for rooftop solar investment to competitively replace large-scale solar investment, that is not the case when batteries are included. This is because batteries are a significant extra capital cost which is not compensated for by substantial extra subsidies. High capital costs are compounded for rooftop systems which have a low capacity factor compared to large-scale solar which includes single axis tracking. The Victorian government does have a scheme whereby a subsidy of $4174 is available for a limited number of batteries. The effect of this subsidy is included in the range shown.[68] As this is flat subsidy, we also calculated the system costs for a smaller system, from 10kW to 7kW. This was not enough to make rooftop solar and batteries competitive with its large-scale substitute.

[68] We assume it is constant over time for lack of any other firm values, but it may be revised downward over time making the transition at 2030 less abrupt.

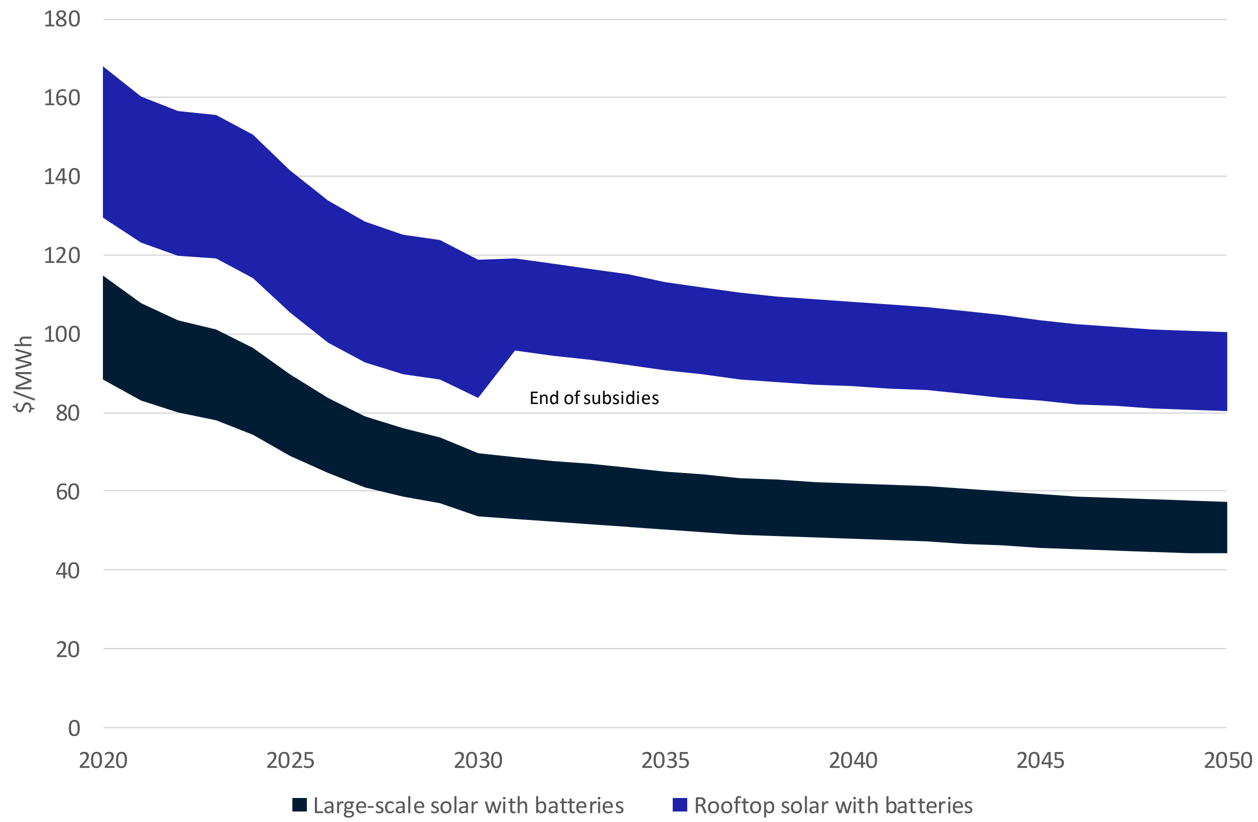


Figure 33 - Comparison of the levelized costs range of rooftop solar with batteries and large-scale solar with batteries

Given the relative costs of the two competing technologies, there is no generation sector benefit to be found from investment in solar-battery systems above the business as usual to take advantage of higher export limits. They would only displace lower cost investment in large-scale systems. However, all solar-battery systems that existed in the business as usual and that are large enough to use the extra capacity (and are currently limited in their operation by the existing export limit) would provide benefits. The benefit of all additional energy provided is $96/MWh to $119/MWh in 2020. The present value per MW in 2020 of additional capacity is $350,000 to $1,119,000 (this halves within five years due to technology costs reductions).

However, given that the number of large existing batteries may be limited, perhaps a larger resource in the business as usual is electric vehicles which we explore in the next example

Generation total cost method applied to combined energy and capacity services: - static 5 kW export limits converted to static 10 kW limits for electric vehicles

In this example the network has identified customers in the business as usual that will purchase electric vehicles mainly for transport services of a certain range (battery capacity) but it has a vehicle to grid capability that is potentially large. Consequently, expanding export limits might provide more flexible energy or capacity services to the wholesale market from DER that already exists in the business as usual.

The expansion of the export capacity provides additional flexible energy and capacity that competes with large scale batteries. We focus on the capacity component of this combined service. We could also include the energy as part of the technology package by valuing the net change in energy exported each day, but this is likely the smaller of two value streams because the throughput potential of the storage has not changed. While we do not include the energy value, networks can choose to include it if the capacity value alone is not sufficient to establish the investment case. A total generation cost method is the appropriate valuation method since it is likely the availability of the increased DER capacity could reduce the need for large-scale flexible capacity.

Networks will need to conduct simulations to determine the duration of the use of the additional DER capacity in order to select the duration of large-scale battery they will be avoiding. Longer duration batteries are more costly and so the greater is the benefit the longer is the maximum operation of the additional DER. For this example, the additional DER capacity avoids the need to build some 4 hour large scale batteries which would otherwise have discharged into the peak evening period (which under the simulations in the previous example was the most attractive use of the capacity in most states). Base on GenCost 2019-20, 4 hour large scale batteries are $1964/kW or $1,964,000/MW in 2020 (Graham et al., 2020). Given the example may relate to vehicle to grid which may not be deployed in substantial numbers for another decade, the 2030 value of $828,000/MW, which accounts for further reductions in the cost of large-scale batteries, may be more relevant.

It is possible this capacity might also provide a network benefit where the vehicle battery operation aligns with network peak demand reduction or if it is incentivised to provide capacity services in both markets. The average cost of network capacity is the relevant benefit metric in this case. Adding benefits across or within sectors rests on the network providing evidence of vehicle battery capacity being able to plausibly operate in this manner and assigning only the capacity that was used in those separate markets to their respective benefits.

Meet environmental requirements

There are two methods for calculating value of additional DER in meeting environmental requirements. The first is a generation sector total cost method, because it avoids the need to build other equivalent large-scale generation that meets the environmental requirement. As discussed above, this avoided large-scale generation capacity benefit cannot be added to other benefits due to the problem of double counting. As such, this benefit method would only be chosen when it surpasses any other benefit of the additional energy.

The alternative is to use an environmental price directly, particularly where the amount of generation required to meet the environmental requirement is unclear. Ideally, in this case, a government provides a clear price signal to value the additional energy which meets the requirement.

Generation total cost method: environmental services

The formula for the implementation of this method is similar to that in the energy services method except that there is no adjustment via an annual capacity factor ratio. This simplifies the formula to:

$$PresentValueofAdditionalDER = \sum_{t=1}^{T}\left[\frac{1}{(1+DiscountRate)^{t-1}} \times AdditionalDEROutput_t \times \left(\frac{TotalCostStandardGenerationSolution}{AverageTransmissionLossRate} - TotalCostDER\right)\right]$$

Where, the *TotalCostDER* need only be subtracted for DER that is additional investment in DER capacity relative to the business as usual.

TotalCostStandardGenerationSolution is in dollars per MWh and will change over time with changes in technology costs and could be an average of displaced technologies that meet the environmental requirement. The *AverageTransmissionLossRate* is assumed to be constant over time but could be varied if there were projected changes available.

The set t=1,…….T is time in annual steps up to T which is the whole period the additional DER is enabled

$$TotalCostStandardGenerationSolution_t = AnnualisedCapitalCost_t + AnualisedOperating\&MantenanceCost + FuelCost_t$$

These values are calculated for multiple technologies as necessary if an averaging approach is taken.

Where,

$$AnnualisedCapitalCost_t = \frac{(1+Discountrate)^{ConstructionPeriod} \times CapitalCost_t}{AnnualCapacityFactor \times 8760} \times \frac{Discountrate \times (1+DiscountRate)^{economiclife}}{[(1+DiscountRate)^{economiclife} - 1]} +$$

8760 is hours in a year

CapitalCost is in dollars per MW and the first term immediately before that is simplified way of accounting for interest lost during construction. This can be reduced and modified for construction projects longer than a year where the initial capital drawn down may occur over several years.

$$AnnualisedOperating\&MantenanceCost = VariableOpertaing\&MaintenanceCosts + \frac{FixedOperating\&MaintenanceCost}{AnnualCapacityFactor \times 8760}$$

Where *VariableOperatingCost* is in dollars per MWh and *FixedOperating&MatintenanceCost* is in dollars MW.

Input fuel costs, where they apply, are converted from input costs in dollars per gigajoule to a common energy standard of dollars per megawatt hour as follows:

$$FuelCost_t = \frac{\$}{GJ} \times \frac{3.6}{FuelEfficiency}$$

A worked example of this method is not shown because it is similar in its results to the worked method for increasing export limits.

Environmental price method

In circumstances where an environmental price has been provided the formula for calculating the benefit of additional DER is simply:

$$PresentValueofAdditionalDER = \sum_{t=1}^{T}\left[\frac{1}{(1+DiscountRate)^{t-1}} \times \frac{AdditionalDEROutput_t}{AverageTransmissionLossRate} \times ChangeEnvironmentalOutcome_t \times EnvironmentalServicesPrice_t\right]$$

Where *EnvironmentalServicesPrice* is typically expressed in terms of the price the government is willing to pay to avoid a negative outcome, such as emissions. In such cases the formula is rearranged to:

$$PresentValueofAdditionalDER = \sum_{t=1}^{T}\left[\frac{1}{(1+DiscountRate)^{t-1}} \times \frac{AdditionalDEROutput_t}{AverageTransmissionLossRate} \times (EmissionFactorGrid_t - EmissionFactorDER) \times EnvironmentalServicesPrice_t\right]$$

Environmental price method: worked example

In this example we assume no region has renewable energy targets, but the governments are willing pay for any emission reduction in the electricity sector to a value of \$15/tCO_2e (this value was chosen based on the current price of Australian Carbon Credit Units). Regional emission factors are available from *National Greenhouse Accounts Factors,* which is updated annually. The current values are shown in Table 17.

The change in the emissions factor should ideally be calculated from AEMO ISP results. For this example, a 50% reduction by 2030 is assumed. Applying these assumptions, the value per MWh of additional rooftop solar is shown in Figure 34. The value is lowest in states with already low grid emission factors such as SA and TAS. For 1 MW of additional generation from the synthetic tripped profile for rooftop solar PV we used in previous examples, the net present value to 2030 is calculated as \$5,000 to \$36,000 across the regions, with Victoria being the highest due to its higher grid emission factor. This benefit can be added to other benefits, such as from energy services or combined energy and capacity services, because the environmental price is external to the market requirements.

Table 17 – Regional greenhouse gas emissions factors

Region	Emission factor tCO_2e/MWh
New South Wales and Australian Capital Territory	0.81
Victoria	1.02
Queensland	0.81
South Australia	0.44
South West Interconnected System (SWIS) in Western Australia	0.69
North Western Interconnected System (NWIS) in Western Australia	0.59
Darwin Katherine Interconnected System (DKIS) in the Northern Territory	0.55
Tasmania	0.15
Northern Territory	0.63

Source: DoEE (2019)

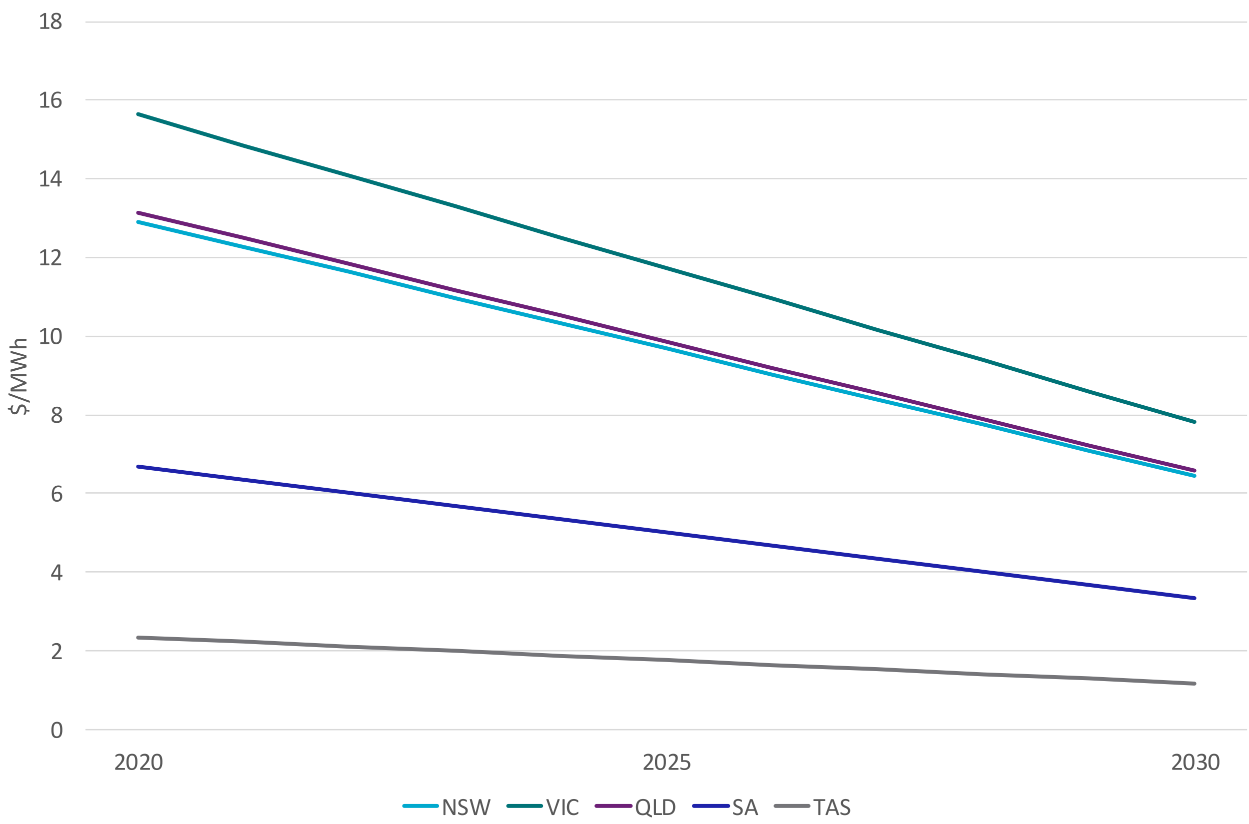


Figure 34- Value per MWh of additional rooftop solar environmental services under a $15/$tCO_2e$ environmental price

Implications for use of feed-in tariffs and environmental prices

The Essential Services Commission (ESC) of Victoria publishes a rooftop solar feed-in tariff. In 2019-20 the time varying feed-in rate was 9.9 and 14.6c/kWh during off-peak and peak respectively or a single daytime feed-in tariff at 11.6c/kWh. For 2020-21 the daytime rate has fallen to 10.2 c/kWh and the time vary rate has fallen to 9.1 to 12.5c/kWh, mainly in recognition of falling wholesale prices[69].

The ESC calculates these fees as the sum of projected electricity prices in Victoria at the relevant time of day and adjusts for transmission losses. They also calculate two other items, a 2.5c/kWh avoided environmental cost and avoided AEMO charges (which are fairly negligible for comparison purposes). The Victorian environmental charge considers avoided greenhouse gas emissions.

If we remove the environmental fee and ignore the AEMO charges, then the ESC's valuation of rooftop solar PV generation adjusted for avoided transmission loss as a single rate was $91/MWh in 2019-20 and is projected to be $77/MWh in 2020-21. These values for variable energy are much higher than those considered in the tripped solar worked example here because they are the value for a full rooftop solar production profile[70], not the narrower generation profile for additional solar that was previously tripped off due to hosting capacity constraints. If we apply the generation running cost method to a full rooftop solar profile in 2019 and 2019-20 the values the method would calculate for variable energy are $105/MWh and $66/MWh[71] respectively. However, these values are not appropriate because this is not the likely profile of the additional DER from tripped rooftop solar. The conclusion from these comparisons is that energy value from the Victorian feed-in tariff may be inappropriate to value variable energy unless a network can show evidence that the additional DER they are providing matches the full generation profile of rooftop solar PV for which the feed-in tariff is designed.

However, it may be appropriate to use the price for environmental services provided by the Victorian government. In this case, the environmental services value is outside of the market and therefore additional to the variable energy services. Victoria's environmental price is set by a method determined by the government and includes additional environmental services value. By only taking account of greenhouse gas emissions and using an Australian Carbon Credit Unit price of $15/t$CO_2$e we estimated an environmental price of $16/MWh compared to $25/MWh (2.5c/kWh) under the Victorian government method. Use of the environmental price provided by the Victorian government should include an appropriate adjustment factor over time for declining emission intensity of the grid.

From the worked example of variable energy from tripped rooftop solar, we can add our generation running cost method energy value of $38/MWh in Victoria to the government set environmental price of $25/MWh (both declining over time). This gives an initial value of $63/MWh compared to the 2020-21 Victorian feed-in tariff single rate of $102/MWh. The estimated net present value of the additional variable energy over 30 years is $289,000/MW.

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[69] https://www.esc.vic.gov.au/electricity-and-gas/electricity-and-gas-tariffs-and-benchmarks/minimum-feed-tariff

[70] The ESC has followed this method only in the last year and in fact the method was time weighted previously. The ESC (2020) report states that "the time-varying minimum FiT rate is now based on solar-weighted wholesale electricity prices instead of the time-weighted approach (technology neutral approach) we used in our most recent two FiT determinations. As such, the approach to calculating the FiT is still evolving.

[71] This price does not line up with the ESC 2019-20 variable energy price because our calculation is based on historical data where the ESC value is based on forecasting 2019-20 prices. As such, in hindsight the ESC overvalued rooftop solar energy in 2019-20 and this was to be expected given the COVID-19 pandemic could not have been predicted. The 2020-21 price appears to have taken lower demand conditions into account and consequently is closer to the historical 2019-20 value.

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Contact us

1300 363 400
+61 3 9545 2176
csiroenquiries@csiro.au
csiro.au

For further information

CSIRO Energy
Paul Graham
+61 2 4960 6061
paul.graham@csiro.au

Cutler Merz
Melanie Koerner
+61 2 9006 1633
melanie.koerner@cutlermerz.com