Value of Distributed Energy Resources (VaDER)

Frequently Asked Questions

Why was the Value of Distributed Energy Resources (VaDER) study undertaken?

As part of the AER's regulatory determination process, a Distribution Network Service Provider will provide the AER with a five-year forecast of its required revenue that it seeks to recover from its customers. Capital and operating expenditures are a significant component of this revenue recovery process. The AER assesses expenditure forecasts to determine if they reasonably reflect the expenditure criteria. In doing so, the AER must have regard to each of the expenditure factors specified in the National Electricity Rules.

Distributed Energy Resources represent a fundamental change to the system of electricity delivery that has been in place for over a hundred years and are therefore a new driver of network expenditure. As such, the AER is in the process of developing a DER Integration Guideline that will provide direction for DNSP's on how to value DER-driven network investment.

The AER commissioned CSIRO and CutlerMerz to help inform the AER's work on this DER Integration Guideline. The purpose of the VaDER study is to identify a framework for DNSPs when considering the value that DER can provide through access to markets or via autonomous functions. As increasing amounts of DER are adopted, a framework or methodology is required to accurately signal networks to support DER connection and access to markets.

What is the methodology for valuing DER that you recommend?

The recommended methodology compares the total electricity system costs when a network spends to increase DER hosting capacity (known as the "investment case") with the total electricity system costs when a network does not spend to accommodate customer DER adoption (known as the "base case"). The difference between these costs represents the benefit or value of DER.

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. 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.

How much should networks be spending on DER integration?

It depends (and our study won't tell you!)

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.

In general, there is a four-step process that a network takes to adopt an approach for identifying the need for a DER integration solution and recovering costs associated with integrating DER. 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 focuses on determining 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.

How does this methodology relate to the recent requests for new rules to better integrate DER for consumers?

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. Some of these proposals seek to create an obligation on networks to enable DER to connect and export at some minimum level to the grid, just as networks today have an obligation to connect any and 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, in advocating for the ability for networks to charge for exports. It is argued that costs to integrate DER should be allocated to those customers who export energy from their premise and therefore benefit from the network. Our methodology is applicable regardless of the way in which the costs of the network expenditure are allocated to DER or non-DER customers. That is, where there is a net overall system benefit of the network investment, then the investment should proceed. Notwithstanding, the ability for a network to charge for export based on the costs of DER integration would enable more cost reflectivity in network prices and potentially lead to more efficient outcomes.

Does the methodology show that network expenditure to increase DER hosting capacity is not worth the cost?

No. Our methodology is focused exclusively on how to calculate the benefits of proposals to integrate DER. It does not address the cost-side of the cost-benefit analysis that networks might perform to consider the economic efficiency of a given DER integration expenditure proposal.

Why have you excluded the "intangible" benefits, such as customers' enjoyment of having locally produced energy powering local communities?

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. In our methodology, these intangible benefits relate to the intangible benefit of additional generation/participation in markets, not of the DER ownership itself. Further, these intangible benefits must be separate from the financial and environmental benefits which we capture elsewhere.

While Energy Consumer Australia's 2019 *Consumer Sentiment and Behaviour* survey results suggest that customers purchase solar panels and batteries for many reasons in addition to saving money, the survey reveals that saving money is also the primary motivation. 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.

It is worth noting that, like customers, investors in and corporate owners of large-scale power plants – or investors in and/or corporate owners of DER that are hosted at a customer's site but owned by a corporate entity – may receive intangible benefits from their investment. Such benefits could include positive public relations and diversification of a broader portfolio of investments. We likewise have not included these intangible and difficult to quantify benefits for investors and corporate owners of large-scale assets and DER.

Customers may be willing to pay additional fees to cover the costs of DER integration (even if such costs exceed the benefits). Does your methodology include customer willingness to pay for DER integration?

No, 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, particularly as it is able to capture intangible benefits. 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, 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 to gage the actual price likely offered to customers may yield a more informative survey and more trustworthy response.

In determining VaDER, why haven't you used something similar to the "Value of Customer Reliability" (VCR) approach also adopted by the AER?

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" – that is, the ability of network supply to provide a customer with a given amount of energy at any time of the 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.

In contrast, DER delivers benefits to the electricity system via several services which are otherwise provided by direct – and largely incumbent – competitors. For example, DER can provide energy and other essential system services, just as large-scale generators can and traditionally have. Given this direct ability to match DER with one-to-one substitutes for the services it provides in the electricity supply chain, the most accurate way to identify value is to compare DER to existing, alternate technologies that provide similar services via modelling or the short-hand methods described.

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.

Your methodology has highlighted the importance of DER adoption forecasts in the base-case or business as usual scenario and an investment scenario. Can you provide further guidance outlining when a network would be expected to demonstrate a change in DER forecasts between scenarios?

For the most part, we think networks rarely should and rarely will change their DER adoption forecasts between a base case scenario and the investment scenario.

Networks should invest to integrate DER based on reasonable assumptions of DER adoption and not in a way that is actively incentivising additional DER adoption. The base case – consistent with RIT-D guidelines – "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". In other words, the base case should identify a challenge in DER integration that occurs because forecasted DER adoption is realised and yet no new network solution is implemented. In other words, in the base case, no new limit is placed on DER connections, no new tariffs are adopted, no changes are made to existing inverter standards, and no other network expenditure is undertaken to address the increase in DER adoption that surpasses network hosting capacity. For this reason, we have developed the worked example of tripping solar because, in practice, this is what we believe would happen in the base case for most networks today. By contrast, in the investment case, DER adoption is identical (it is the same forecast), but networks have implemented some solutions – such as new tariff designs, demand response programs, dynamic operating envelopes, etc. – that avoids the network constraint that caused solar to trip in the base case and limited export to existing levels, even when there is no constraint.

It is worth noting that this outlined approach is different than what some networks have proposed in previous reviews for the base case. In some cases, networks have argued that DER adoption will drop because they have included in the base case a new, more stringent network connection limit (e.g. 2 kW as opposed to 5 kW). Our methodology suggests that in most cases, the DER adoption would be identical, and we assume that most networks will invest to integrate forecast DER, not to actively recruit and grow DER adoption above and beyond projected adoption.

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

Does customer investment in DER need to be included as a cost when considering the value of DER?

In most instances, customer investment in DER does not need to be included as a cost because, as noted above, DER adoption forecasts are identical in both the base case and investment case. While technically the analysis should include DER investment costs, they would be identical in both the base case scenario and the investment scenario and so in practice they cancel out and are not relevant. DER costs should be included when the DER adoption forecast changes due to network investment causing an increase or decrease in DER adoption.

The worked examples did not include a dynamic operating envelopes example. Why not and what would such a case find?

A dynamic operating envelopes example was not included because no data is yet available and, therefore, we were unable to make reasonable assumptions of what such a scheme would look like in terms of the new profile of rooftop solar exports. However, were such data available, the same methodology choices apply. The profile should be examined to determine whether it avoids large-scale investment (where it has a similar profile to large scale technologies) or whether it avoids running costs.

Notwithstanding, our expectation is that the additional generation profile would be narrower and flatter than a static change in export limits because the rooftop solar would access the extra export capacity less frequently. This may support using the running cost method.

Does your methodology require networks to value avoided carbon emissions?

No, our methodology does not require networks to value avoided carbon emissions in their investment decisions, because the AER is unlikely to be able to consider these benefits without either:

- a national or state-based policy in place that imparts a tax or levy on carbon emissions that internalises the cost of carbon within the electricity system; or
- a jurisdictional requirement in place, set by state or territory governments, mandating distribution network businesses to consider the value of avoided carbon emissions.

Notwithstanding, our methodology sets out how the value of carbon emissions could be calculated should such a policy or requirement be in place. We further set out in our recommendations that state and territory governments should consider whether they should require distribution network businesses to value avoided carbon emissions and to nominate an appropriate value (in $ per tonne of carbon equivalent) if so.

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