Draft CECV methodology

Explanatory statement

April 2022

AUSTRALIAN ENERGY REGULATOR

Inquiries about this publication should be addressed to:

Australian Energy Regulator
GPO Box 520
Melbourne VIC 3001
Tel: 1300 585 165

AER reference: 212903

Amendment record

Version	Date	Pages

Request for submissions

Interested parties are invited to make written submissions to the Australian Energy Regulator (**AER**) regarding this paper by the close of business, 6 May 2022.

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

Alternatively, submissions can be mailed to:

Dr Kris Funston
Executive General Manager, Network Regulation
Australian Energy Regulator
GPO Box 520
Melbourne VIC 3001

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

Parties wishing to submit confidential information are requested to:

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

All non-confidential submissions will be placed on the AER's website at www.aer.gov.au. For further information regarding the AER's use and disclosure of information provided to it, see the ACCC/AER Information Policy, June 2014 available on the AER's website.

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

Contents

1 Introduction

This explanatory statement provides our rationale for the Draft Customer export curtailment value (CECV) methodology.

On 12 August 2021, the AEMC made a final determination on updates to the National Electricity Rules (NER) and National Energy Retail Rules (NERR) to integrate distributed energy resources (DER) more efficiently into the electricity grid.[1] The final determination requires us to develop a CECV methodology to be used to calculate CECVs each year and publish values.[2]

The AEMC indicated that CECVs will help guide the efficient levels of network expenditure for the provision of export services and serve as an input into network planning, investment and incentive arrangements for export services. These values will be different from values of customer reliability (VCRs), as they are not intended to measure the value to customers of having a more reliable export service or consumption service, but rather the detriment to customers and the market from the curtailment of exports.[3]

We must ensure that the methodology we develop, and any CECVs calculated in accordance with the methodology, are consistent with the CECV objective. The CECV objective is that the CECV methodology and customer export curtailment values should be fit for purpose for any current or potential uses of customer export curtailment values that the AER considers to be relevant. Also, for the purposes of the new rule:

- customer export means supply to a distribution network of electricity generated by a micro embedded generator or a non-registered embedded generator.
- customer export curtailment means reducing, tripping or otherwise limiting customer export.

1.1 Consultation process

We are required to consult on the CECV methodology under the Rules consultation procedures. Our consultation process commenced with the publication of an issues paper in October 2021 and a public forum in November 2021.[4]

Following the receipt of stakeholder responses to the issues paper in December 2021, we engaged Oakley Greenwood to assist in the development of the CECV methodology. Specifically, Oakley Greenwood considered:

- the potential for wholesale market DER value streams to be estimated under the methodology;

[1] AEMC, 'Access, pricing and incentive arrangements for distributed energy resources, Rule determination', 12 August 2021.

[2] NER rule 8.13.

[3] AEMC, 'Access, pricing and incentive arrangements for distributed energy resources, Rule determination', 12 August 2021, p.61.

[4] Consultation documents and responses to the issues paper are published on the AER website.

- how these DER value streams should be estimated using electricity market modelling; and
- how DNSPs should apply CECV estimates in practice when preparing business cases for DER integration investments.

Oakley Greenwood provided a summary of its recommended approach to quantifying wholesale market value streams at our stakeholder workshop in February 2022. We refer to advice provided in a report by Oakley Greenwood throughout this explanatory statement, and also welcome stakeholder views on this report.[5]

The Draft CECV methodology and this accompanying explanatory statement represent the draft report referred to under the Rules consultation procedures.[6] Submissions on the Draft CECV methodology are due by 6 May 2022.[7] We will consider all stakeholder submissions before publishing a final CECV methodology and values by 1 July 2022.[8]

1.2 Relationship with AER guidance

Our development of the CECV methodology follows our proactive and extensive consultation processes on the valuing of DER and our approach to assessing DER integration expenditure. In November 2019, we published a consultation paper outlining issues related to the assessment of DER integration expenditure. We then commissioned the CSIRO and CutlerMerz to conduct a study into methodologies for determining the valuing of DER (VaDER) and published this final report in November 2020.[9] We formalised the recommendations of the VaDER methodology study through the publication of our draft DER integration expenditure guidance note in July 2021.[10] Prior to the development of this guidance note, our assessment of expenditure for DER integration has largely been in line with our RIT-D guideline, which recognises the potential to quantify different classes of market benefits, but does not cater specifically to DER integration investments.[11]

We expect that the final CECV methodology will supplement our final DER integration expenditure guidance note, which is also planned for publication by July 2022. Our guidance note outlines the potential DER value streams that may be quantified by DNSPs in their cost-benefit analyses for expenditure to increase DER hosting capacity, and how these values should be quantified. The draft CECV methodology provides our approach to valuing a subset of these DER value streams (specifically those related to the wholesale electricity

[5] Oakley Greenwood, CECV Methodology – Interim Report, 6 April 2022.

[6] NER rule 8.9(h).

[7] Valid submissions must be received not later than the date specified in the notice (not to be less than 10 business days after the publication of the draft report pursuant to rule 8.9(h) or such longer period as is reasonably determined by the consulting party having regard to the complexity of the matters and issues under consideration.

[8] We must consider all valid submissions within a period of not more than a further 30 business days.

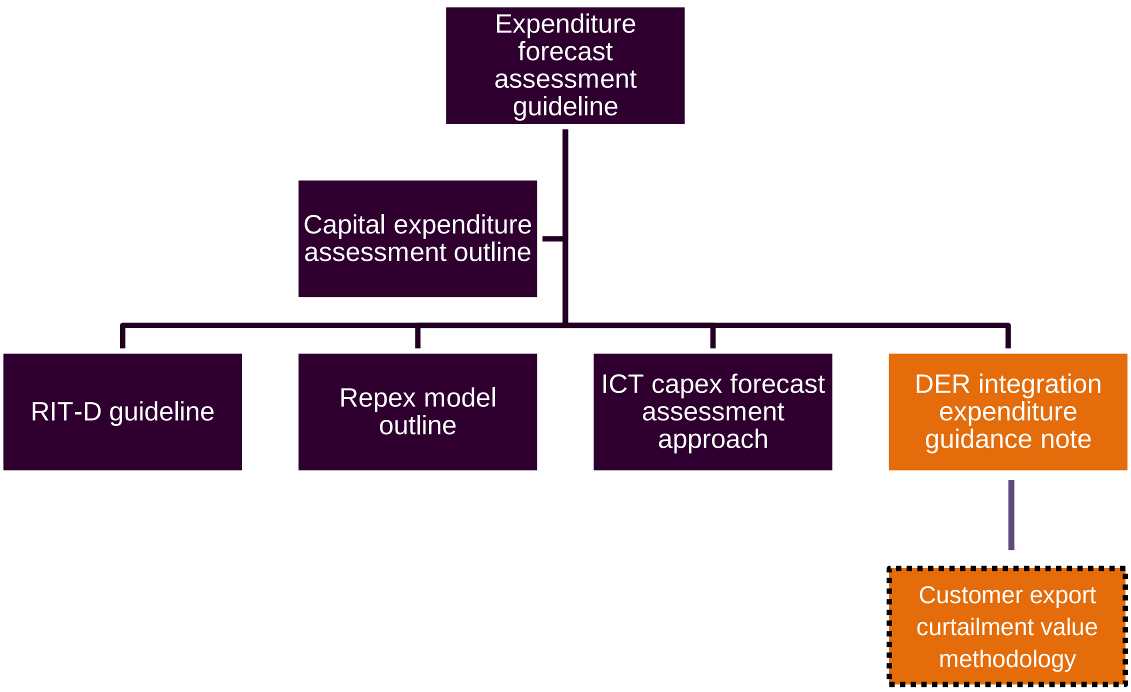
[9] Koerner M, Graham P, Spak, B, Walton F, Kerin R (2020), 'Value of Distributed Energy Resources, Methodology Study: Final Report', CutlerMerz, CSIRO, Australia.

[10] AER, 'Draft Distributed Energy Resources Integration Expenditure Guidance Note', 6 July 2021.

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

market) and provides a consistent approach for DNSPs to undertake their cost-benefit analyses. Figure 1.1 illustrates the CECV methodology within our expenditure assessment toolkit. The Expenditure forecast assessment guideline describes the process, techniques and associated data requirements for our approach to setting efficient expenditure allowances for network businesses. Further to this high-level guidance, we have published several standalone guidance documents for expenditure relating to major investments, large-scale and continuous replacement programs and new technologies to manage electricity networks. The DER integration expenditure guidance note and CECV methodology supplement these pieces of guidance by providing clarity and certainty to DNSPs and their customers about how to prepare expenditure proposals for investments related to DER integration, and how we will assess these proposals.

Figure 1.1: CECV methodology and distribution expenditure assessment toolkit



The AEMC's final determination also removed the existing prohibition on distribution businesses from developing export pricing options, and requires us to develop Export Tariff Guidelines by 1 July 2022. We are developing these guidelines under a separate consultation process.[12]

[12] AER, 'Draft Export Tariff Guidelines', January 2022.

1.3 What do we want to know from stakeholders?

We seek stakeholder views on a number of aspects of our proposed CECV methodology. Questions in this paper are summarised below.

Table 1.1: Consultation questions

Questions	
Question 1	What are your views on the value streams to be captured in the CECV?
Question 2	What are your views on our interpretation of customer export curtailment and the concept of the alleviation profile?
Question 3	What are your views on our interpretation of the distribution of costs and benefits, including the relationship between CECVs and export charges?
Question 4	Do you agree that half-hourly CECV estimates are appropriate?
Question 5	Do you agree that CECV estimates for each NEM region are appropriate?
Question 6	Do you have any views on the model inputs and assumptions and the process of estimating CECVs?
Question 7	Do you have any views on the factors we should consider in updating CECVs annually, as well as potential triggers for reviewing the CECV methodology prior to the five-yearly review?
Question 8	Do you support the DNSP model allowing for the self-selection approach?
Question 9	Do you support the DNSP model allowing for the characteristic day approach?
Question 10	Do you support the DNSP model allowing for the ranking of characteristic days approach?
Question 11	Do you have views on the ranking of characteristic days?

1.4 Structure of this paper

This explanatory note is structured as follows:

- Section 2 – Interpretation of CECV. Here we discuss the value streams captured in the methodology.
- Section 3 – Estimation of CECV. Here we discuss how we estimate these values, including the inputs, assumptions and the process for updating CECVs.
- Section 4 – Application of CECV. Here we discuss the options provided to DNSPs for applying the estimated CECVs to quantify the benefit of investments that address customer curtailment.
- Appendix A – Stakeholder submissions.

The CECVs estimated using the draft CECV methodology are published separately.

2 Interpretation of CECV

In this section we discuss our interpretation of the CECV under the draft CECV methodology. This includes the DER value streams that are estimated as CECVs, and how we account for customer export curtailment in estimating these values.

2.1 DER value streams

The VaDER methodology study identified DER value streams which describe the types of costs and benefits that may arise as a result of a network investment to increase DER hosting capacity. Our draft DER integration expenditure guidance note allows DNSPs to propose expenditure for network investments that increase DER hosting capacity, and subsequently permit a greater level of DER exports. To do this, DNSPs should compare the proposed expenditure against the net sum of benefits under each value stream (where they are applicable). Our draft guidance note sets out the methods that DNSPs should use to quantify each value stream. Similarly, if customer exports from DER are curtailed (and the level of DER exports to the electricity grid are lower), it is possible to estimate the cost to consumers. Table 2.1 summarises the DER value streams according to benefit type.

Table 2.1: DER value streams provided by AER guidance

Benefit type	Value stream	How DER integration delivers value stream
Wholesale market	Avoided marginal generator short run marginal cost (SRMC)	DER exports substitute for generation by marginal centralised generators, which may have higher SRMC (fuel and maintenance costs).
	Avoided generation capacity investment	Increased DER export capacity reduced the need for investment in centralised generators.
	Essential System Services (ESS) (including FCAS)	Increase DER capacity enables greater participation in ESS markets, reducing the need for investment in centralised ESS suppliers.
Network sector	Avoided or deferred transmission/distribution augmentation	Increased DER exports reduces load and can reduce peak demand, leading to avoided or deferred network investment.
	Distribution network reliability	DER can supply customers and local networks after network outages, reducing unserved energy and outage duration.
	Avoided replacement/asset derating	Increased DER can lower the average load on network assets, enabling asset deratings and the installation of smaller and cheaper assets.
	Avoided transmission/distribution losses	Increased DER exports can reduce supply via transmission lines and reduce the distance energy must travel within distribution networks. This results in less energy lost to heat during transportation.
Environment	Avoided greenhouse gas emissions	Only applicable where there is a jurisdictional requirement to consider (otherwise already included in wholesale market benefits).
Customer	Change in DER investment	Applicable where the DNSP's investment results in a change in customer investment. For example, an investment which results in a customer deferring investment in battery storage is considered a benefit as DER owners are producers of electricity.

Ideally, the CECV should capture all DER value streams listed in Table 2.1. In this way, the CECV would represent the maximum benefit value for input into DNSPs' investment proposals. However, the values of some benefit types, such as for the network sector, would have very significant spatial variation, and so it would not be appropriate to set a value at an all-of-network or jurisdiction level.

In the issues paper we provided our initial view that the CECV methodology provide the methodology for calculating wholesale market benefits, as these may be calculated independently in a relatively straightforward manner. We suggested that the CECV should focus on the avoided marginal generator SRMC value stream, as this is the simplest of the three wholesale market value streams to estimate and the only one so far estimated by DNSPs in proposals for DER integration expenditure. Our preference was to estimate changes in wholesale market costs rather than prices, as prices incorporate factors which do not represent economic benefits, such as generator ramping costs and portfolio bidding strategy effects. We suggested that DNSPs are best positioned to estimate other benefits, including network sector benefits. We also acknowledged that estimating the benefits associated with every value stream may be very complicated and the benefits may be very small or non-existent.

2.1.1 Stakeholder responses

A number of stakeholders agreed that the CECV methodology should estimate wholesale market DER value streams. Ausgrid suggested that CECVs should reflect all wholesale market value streams, including the avoided marginal generator SRMC, the avoided generation capacity investment and essential system services.[13] Endeavour Energy expressed concern that only looking at avoided marginal generator SRMC will lead to CECVs being understated. It expected that avoided generation capacity investment will be increasingly important to consider as battery storage and other large-scale renewable generation increasingly become marginal.[14]

Some stakeholders also suggested that the CECV should comprise other value streams, including customer willingness to pay. Ausgrid suggested that customer preferences should determine the value of DER investment and these preferences should be reflected in the benefit streams, and suggested that tangible environmental benefits should also be reflected in the valuation of DER investments.[15] CitiPower, Powercor and United Energy did not agree that the scope of the CECV should be limited to estimating dispatch costs. It suggested that we should take a more holistic approach to understanding and quantifying customer value of export curtailment by incorporating the intrinsic customer value of choice and control of enabling exports and the customer value of environmental benefits of enabling exports.[16]

[13] Ausgrid, 'Submission to the customer export curtailment value methodology', December 2021.

[14] Endeavour Energy, 'Submission to the customer export curtailment value methodology', December 2021.

[15] Ausgrid, 'Submission to the customer export curtailment value methodology', December 2021.

[16] CitiPower, Powercor & United Energy, 'Submission to the customer export curtailment value methodology', December 2021.

2.1.2 Draft decision

In the initial methodology CECVs will quantify the impact of incremental DER export on wholesale market production cost (the marginal generator SRMC), accounting for aggregated headroom and footroom allowances for FCAS services and transmission and distribution losses (from generation to the regional reference node). We consider that this approach ensures that CECVs represent the most material wholesale market costs/benefits, and the process of estimating CECVs will be relatively straightforward and understood. In section 3 we detail our modelling process for estimating CECVs.

In deciding on the values to be captured in the CECV we considered advice from Oakley Greenwood. It noted that modelling the value of additional DER export could be undertaken using a "with/without" approach or a "marginal" approach. The marginal approach is preferable to the with/without approach as it does not require an assumption of an "alleviation profile"[17] to represent the additional DER export and provides flexibility for users to select appropriate values that are reflective of technological and locational characteristics.

The initial methodology does not quantify the impact of incremental DER export on possible changes to generation or transmission system investment costs, as this would require a with/without approach to modelling. Oakley Greenwood also noted that it expects the investment impact to be small for two reasons:

- Firstly, between now and the medium term, DER curtailment will mostly occur when there is an abundance of system generation and/or low system demand (i.e., high solar output period). The periods in which additional generation capacity is needed are often after dark where curtailment of most of the DER currently and expected to be in place is unlikely.
- Secondly, the amount of DER curtailment is small relative to the system generation.[18]

We also do not consider changes in ESS provision where these might result in material differences to either the total amount of headroom and footroom allowances already included in the analysis or its allocation across the various FCAS services.

DNSPs are not precluded from quantifying other value streams listed in Table 2.1 themselves, including avoided generation capacity investment. Our final DER integration expenditure guidance note will provide detail on how these value streams should be quantified and also address other value streams suggested by stakeholders. The CSIRO and CutlerMerz noted that the NEO places an overarching requirement on us to make distribution determinations that will deliver efficient outcomes in the long-term. The value streams that we may consider must ultimately transfer benefits to electricity consumers in the long-term

[17] The projected amount and time profile of the additional DER export that is enabled by each proposed projects to increase DER hosting capacity.

[18] Oakley Greenwood, CECV Methodology – Interim Report, 6 April 2022.

and must be shown to increase consumer and producer surplus[19] – that is, the value streams must improve the welfare of both consumers and producers.[20]

Question 1: What are your views on the value streams to be captured in the CECV?

2.2 Curtailment

In the issues paper we noted that DER export curtailment can occur when local network voltages exceed statutory limits, and that a range of definitions exist in the context of solar PV systems. We noted that identifying export curtailment, along with its cause, is a challenging exercise due to location-specific and temporal factors. It also requires a degree of estimation, as DNSPs lack visibility of conditions on their low-voltage networks and are unable to identify instances of curtailment solely based on metering data.

We suggested that, for the purpose of calculating CECVs, we do not necessarily need to identify instances of curtailment and estimate the impacts on specific customers, but rather assume that curtailment is a scenario where a lower level of DER export occurs relative to an expected level. In this way, DNSPs would forecast a level of DER exports provided by their proposed investment and would use CECVs to value the difference in the level of DER exports under their base case scenario and investment scenario.

2.2.1 Stakeholder responses

Stakeholders agreed that, broadly speaking, curtailment is a scenario where DER exports are lower than an expected level. AusNet Services agreed that curtailment should be considered a scenario where a lower level of DER export occurs relative to an expected level. It noted that appropriately defining those scenarios will be a key challenge of the CECV methodology, and DNSPs should have the flexibility to select the input assumptions they consider most appropriate, with the default position that those inputs are deemed reasonable unless demonstrated to be otherwise.[21] Ausgrid suggested that AEMO ISP assumptions and scenarios should be used as the basis to develop CECVs, however we should adopt more nuanced localised CECVs and allow DNSPs to put forward localised CECVs where data allows.[22]

Some stakeholders suggested that we clarify our interpretation of export curtailment for the CECV methodology. Jemena suggested that our interpretation of export curtailment is too narrow. It noted that export constraints are broader than just voltage issues, and system security and minimum demand concerns could cause DNSPs to curtail customer exports. Ignoring these network features could potentially understate the total volume of expected

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

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

[21] AusNet Services, 'Submission to the customer export curtailment value methodology', December 2021.

[22] Ausgrid, 'Submission to the customer export curtailment value methodology', December 2021.

constrained exports, which would weaken DER integration investment cases.[23] The Consumer Challenge Panel suggested that we should be more explicit in what is meant by curtailment. It questioned whether it is related to long-term fundamental network hosting capacity (such as non-coincident maximum demand), or a much more dynamic, time varying value that reflects local network conditions, demand and generation diversity, inbuilt control mechanisms and customer self-consumption incentives.[24] The Public Interest Advocacy Centre expressed concern with our view that we do not need to identify instances of curtailment and estimate the impacts on specific customers to calculate CECVs, and suggested that we work towards gathering evidence of actual curtailment from distributors to develop more accuracy.[25]

2.2.2 Draft decision

We recognise that export constraints and subsequent curtailment can occur due to many reasons, and not just due to local voltage issues. There can also be technical reasons for curtailing DER exports in order to protect customers and the electricity network. Under the new rule, customer export curtailment is defined as reducing, tripping or otherwise limiting customer export.[26]

In practice, our draft methodology requires that DNSPs consider the impact of customer export curtailment in estimating the alleviation profile associated with proposed investments. An alleviation profile captures the quantity and time distribution of DER export that, in the absence of the proposed investment, would have been curtailed. The alleviation profile is needed to accurately select CECVs according to the proposed investment. Developing this profile requires DNSPs to consider:

- the current and forecast penetration, sizes and export potential of the various types of DER present and expected to be adopted in the network area affected by the proposed project.
- the current hosting capacity within the network area affected by the proposed project.
- the amount and timing of curtailment currently taking place in the network area affected by the proposed project and how that might change due to forecast changes in the type or amount of DER within the network area affected by the proposed project over the useful life of the assets installed through the project.
- the characteristics of the project to increase hosting capacity, and how those characteristics can be expected to reduce the amount of DER export that will be curtailed and the timing of those reductions in curtailment.

In section 4 we provide more detail on how the DNSP model functions and the options for inputting alleviation profiles into the model. The onus is on DNSPs to estimate alleviation profiles based on the amount and timing of curtailment, however, the DNSP model can

[23] Jemena, 'Submission to the customer export curtailment value methodology', December 2021.

[24] Consumer Challenge Panel, 'Submission to the customer export curtailment value methodology', December 2021.

[25] Public Interest Advocacy Centre, 'Submission to the customer export curtailment value methodology', December 2021.

[26] NER rule 8.13(a).

significantly reduce the complexity of developing alleviation profiles. Estimating alleviation profiles does not change the way that we estimate CECVs—these will be based on the modelling detailed in section 3. However, the concept of the alleviation profile aligns with stakeholder suggestions to allow DNSPs to propose more localised CECVs, as the aggregation of CECVs will be based on the specific investments proposed by DNSPs.

Question 2: What are your views on our interpretation of customer export curtailment and the concept of the alleviation profile?

2.3 Distribution of costs and benefits

In its determination, the AEMC noted that CECVs may need to capture not only the detriment of export curtailment to the customers using the export service but also the potential detriment to all customers from lower levels of customer exports.[27]

In the issues paper we discussed the nature of costs and benefits related to the curtailment and enablement of DER exports. We noted that wholesale market value streams, such as changes in marginal generator SRMC, are reflected in electricity prices—initially impacting DER customers' earnings from feed-in tariffs (both negatively and positively), and over time impacting the electricity prices paid by all customers. We suggested that CECVs should reflect the detriment to all customers from the curtailment of DER exports, and not vary according to customer type, since the impacts are felt by all customers and not just DER customers.

We also discussed the relationship between CECVs and export tariffs[28], which may be imposed by DNSPs for the export of electricity by customers with DER. We noted that export charges should reflect only the incremental cost of providing additional export capacity, and not the capacity of the network used for providing the consumption service.

We sought views on whether CECVs should be specific to particular customer groups (such as DER and non-DER customers), and whether the relationship between CECVs and export charges should be more explicit.

2.3.1 Stakeholder responses

Stakeholders provided mixed responses on whether CECVs should be estimated for particular customer groups, such as DER and non-DER customers. Jemena agreed that CECVs should represent the detriment to all end-users from the curtailment of exports and not particular customer groups. It noted that the wholesale market benefits associated with displaced generation will accrue to all network end-users, regardless of if they own DER systems or export energy back onto the network.[29] Ausgrid suggested that CECVs should be

[27] AEMC, 'Access, pricing and incentive arrangements for distributed energy resources, Rule determination', 12 August 2021.

[28] An export tariff is one that includes a charge for exporting electricity into the grid. It may incorporate both penalties and rewards for customers to export power at different times, according to network needs.

[29] Jemena, 'Submission to the customer export curtailment value methodology', December 2021.

specific to network customer groups, as targeted CECVs will allow for more accurate valuations of the impact of curtailment by electricity distributors.[30]

Most stakeholders agreed that although there is a relationship between CECVs and export tariffs, it is not a direct one, and the value of export tariffs should reflect the LRMC of export service provision. Endeavour Energy noted that, in general terms, tariffs for export services will signal the LRMC of a DNSPs DER integration investment (as per the Pricing Principles) and will not be influenced by wholesale market factors captured by CECVs. Although, it suggested that DNSPs should have the flexibility to share these investment costs between DER and non-DER customers in response to customer feedback and preferences on tariff structures.[31] SA Power Networks suggested that the relationship is more direct, noting that ultimately it is customers of export services that will pay for the network costs of enabling this service, and therefore it is important that the value they see in avoiding service curtailment (arising from insufficient network hosting capacity) is considered.[32]

2.3.2 Draft decision

The draft methodology estimates a set of CECVs that reflect the detriment to all customers from the curtailment of DER exports, and similarly, the benefit to all customers from the alleviation of curtailment. We do not propose to estimate different CECVs for DER customers and non-DER customers. All DER value streams, including wholesale market value streams, are likely to vary according to a number of factors, including customer type, time and location, depending on the proposed DER integration investment. The common distribution service is a standard control service (SCS) and refers to the bundled distribution service provided to customers that use the shared distribution network.[33] The common distribution service is classified as a SCS under our Distribution Service Classification Guideline because all customers benefit from the service. If the export service is classified as a SCS, the relevant benefit streams are those that provide benefit to all customers. In the context of investment planning, it is necessary that DNSPs demonstrate that total net market benefits to all customers exceed proposed costs, and not distinguish between customer types.

DNSPs should demonstrate how their proposed pricing structures will affect the demand for consumption and export services, make best use of existing network hosting capacity and potentially defer network investments. The draft export tariff guidelines set out how DNSPs should propose export tariffs in their tariff structure statements.[34] Where the CECV has been used as an input to support export service expenditure, the CECV could indirectly relate to the cost of providing additional hosting capacity for export. The draft export tariff guidelines state that the costs related to consumption and export services should be kept separate for developing tariffs.[35]

[30] Ausgrid, ‘Submission to the customer export curtailment value methodology’, December 2021.

[31] Endeavour Energy, ‘Submission to the customer export curtailment value methodology’, December 2021.

[32] SA Power Networks, ‘Submission to the customer export curtailment value methodology’, December 2021.

[33] ‘AER, ‘Service Classification Guideline’, September 2018.

[34] AER, ‘Draft Export Tariff Guidelines’, January 2022.

[35] AER, ‘Draft Export Tariff Guidelines’, January 2022.

CECVs will likely represent some of the value of proposed investments to increase hosting capacity, but not necessarily all of the value. Under our DER integration expenditure guidance note, DNSPs will be permitted to identify and quantify other value streams, including network sector benefits such as avoided or deferred network augmentation.

Finally, it is the cost (via the return on and return of capital), rather than value, that DNSPs recover through their revenue allowances. Indeed, the value could be significantly higher than the costs incurred, particularly for high yield non-network solutions. Future expenditure undertaken to expand network hosting capacity above its intrinsic hosting capacity, including both LRMC and residual costs associated with export services, may be signalled through export charges.[36]

Question 3: What are your views on our interpretation of the distribution of costs and benefits, including the relationship between CECVs and export charges?

[36] AER, 'Draft Export Tariff Guidelines', January 2022.

3 Estimation of CECV

In the previous section we provided our interpretation of what we are estimating as CECVs. In this section we discuss the level of temporal and locational granularity at which we estimate these values and the modelling process undertaken to perform the estimation.

3.1 Temporal nature of costs

In the wholesale electricity market, dispatch prices are determined every five minutes, and so there are 288 different values in one day for each NEM region. The value of reducing DER export curtailment will depend on the condition of the wholesale market at the time of the reduced curtailment, with the value of DER export likely to be lower in the middle of the day when the dispatch cost of the marginal generator is generally low, but higher during late evening when more expensive gas generators are often the marginal generator. While currently DER export primarily comes from rooftop solar PV, which is likely to be constrained in the middle of the day, the timing of DER export could shift to other periods in the future. For example, household batteries and electric vehicles could change consumption profiles and lead to more DER exports when the sun is no longer shining.

Estimating the changes in values over the course of a day, month or year provides a practical challenge for DNSPs in quantifying an overall value associated with a proposed DER integration investment. When presenting its cost-benefit analysis, we expect DNSPs to assume a set of values over the economic life of the proposed investment, which may be up to 20 years. This may be challenging as the timing of export curtailment is likely to change in the future as technology and consumer behaviour evolves. In the issues paper we sought views on the appropriate temporal aggregation for estimating CECVs and whether we should forecast CECVs into the future.

3.1.1 Stakeholder responses

Stakeholders generally agreed that a high level of disaggregation was required to capture temporal differences in values. Stakeholders also agreed that a consistent approach to forecasting CECVs into the future is necessary.

The Australian Energy Council (AEC) submitted that CECVs need to be captured on a granular level to the extent possible by using short interval CECVs, aligned to five-minute settlement, which are applied to an intra-regional level at a minimum of hourly. This exposes the true costs to augmenting network to accommodate daytime export. The AEC acknowledged that networks could aggregate this with reference to their own infrastructure build or pricing proposals, such as pricing a storage investment for one quarter in a year, where they have CECVs aggregated by month (and not by year) for that investment case.[37] AGL submitted that the level of aggregation of CECVs should reflect individual DNSPs' proposed investment approaches.[38] Jemena submitted that at a minimum, CECVs should be broken down into three periods throughout the day, including during the middle of the day,

[37] Australian Energy Council, 'Submission to the customer export curtailment value methodology', December 2021.

[38] AGL, 'Submission to the customer export curtailment value methodology', December 2021.

the network peak period and other times. It noted that this is broadly consistent with the approach for establishing minimum feed-in tariffs in Victoria.[39]

3.1.2 Draft decision

The draft methodology provides for the estimation of CECVs on a half-hourly basis. We consider that this represents a sufficient degree of disaggregation and will adequately capture the differences in marginal export value over the course of each day. The methodology recognises the suggestion made by the AEC that networks could aggregate values with reference to their own infrastructure build or pricing proposals by providing DNSPs with several options for aggregating values. Further detail on these options is provided in section 4.

Question 4: Do you agree that half-hourly CECV estimates are appropriate?

3.2 Locational nature of costs

The NEM is a wholesale commodity exchange for electricity across the five interconnected states.[40] The electricity market works as a pool, or spot market, where power supply and demand is matched instantaneously through a centrally coordinated dispatch system. To deliver electricity, a dispatch price is determined every five minutes based on the highest generator bid, which determines the spot price for each NEM region.[41]

In the issues paper, we suggested that it makes sense to estimate CECVs by NEM region, as this would reflect the nature of operations in the NEM. Due to the different regional generation mix, demand profile and the availability of interconnector capacity, the wholesale market benefit of DER export will differ across NEM regions. For other value streams, such as for the network sector, DNSPs may be able to estimate benefits at a more granular location than NEM region. We also highlighted that the increasingly distributed nature of electricity and the increased potential to orchestrate DER has increased the potential for distribution-level investments to provide material benefits to different regions of the NEM. We sought views on whether CECVs should reflect the NEM-wide impact of DER export curtailment.

3.2.1 Stakeholder responses

Stakeholders generally supported estimating CECVs for each NEM region and agreed that CECVs will reflect the impact of DER export curtailment in other regions due to the interconnected nature of the NEM. There were some exceptions to this support; the Consumer Challenge Panel commented that splitting CECVs into regional assessments is well below the level of uncertainty and precision of other calculations impacting customer

[39] Jemena, ‘Submission to the customer export curtailment value methodology’, December 2021.

[40] Queensland, New South Wales, Victoria, South Australia and Tasmania.

[41] Prior to 1 October 2021 six dispatch prices were averaged every half-hour to determine the spot price.

energy prices.[42] Similarly, Energy Queensland suggested that CECVs could be sub-categorised by climate zone.[43] Endeavour Energy suggested that DNSPs should have the flexibility to apply alternative values at a more granular level where accuracy is improved.[44]

3.2.2 Draft decision

Under the draft methodology we estimate CECVs by NEM region as this reflects the structure of the wholesale market, and DNSPs are expected to apply the CECVs for their own region. Under the assumption that CECVs are modelled to reflect wholesale market value streams, it is not possible to estimate CECVs at a more granular level, such as by climate zone. We also do not consider it possible for DNSPs to estimate CECVs themselves at a more granular level, however they could estimate other value streams under our DER integration expenditure guidance that are location specific.

However, the curtailment patterns experienced by DNSPs could have locational variations within a region due to timing and demographic factors. The draft methodology allows DNSPs to obtain a CECV for a specific location within a region to reflect the relevant curtailment (and alleviation) pattern. We discuss this further in section 4 in the context of the DNSP model.

Our methodology has general applicability, but the analysis of wholesale market costs focuses on the operation of the NEM, and therefore, at this stage, does not apply to the Northern Territory's three regulated networks. Although Power and Water Corporation (NT) will not have access to CECVs as inputs to potential business cases via this methodology, we expect that its estimation of benefits associated with avoided dispatch costs should reflect the CECV methodology and adopt appropriate cost effective alternative numerical assessments of dispatch costs that considers both the temporal nature of costs and the alleviation profile associated with any proposed DER integration investments. For example, in the case of the Darwin-Katherine system, dispatch costs may be based on published dispatch related prices in the Interim Northern Territory Electricity Market (I-NTEM) or later NTEM.

Question 5: Do you agree that CECV estimates for each NEM region are appropriate?

3.3 Modelling issues

We have previously discussed whether shorthand approaches (such as simple spreadsheets or tools) or longhand approaches (electricity market modelling) are suitable for estimating wholesale market value streams. There are benefits to both approaches; shorthand methods are simple and easily understood, and longhand methods consider a greater number of inputs and assumptions reflective of market operations, minimise modelling errors and are

[42] Consumer Challenge Panel, 'Submission to the customer export curtailment value methodology', December 2021.

[43] Energy Queensland, 'Submission to the customer export curtailment value methodology', December 2021.

[44] Endeavour Energy, 'Submission to the customer export curtailment value methodology', December 2021.

likely to provide more robust forecasts. Further, AEMO's ISP data is configured for use in PLEXOS, a mathematical model that can be used to project electricity generation, pricing and associated costs for the NEM. We sought views from stakeholders on whether shorthand methods were sufficient for our purpose or whether electricity market modelling was necessary. In the issues paper we also discussed generator bidding and interconnector behaviour and sought views on whether and how these should be modelled.

3.3.1 Stakeholder responses

Stakeholders generally supported us using electricity market modelling to estimate CECVs as this will provide the most accurate estimates. AusNet Services noted that shorthand approaches provide sufficient forecasting ability, and avoid some of the major drawbacks associated with using electricity market modelling, namely the need for agreement on numerous inputs and the lack of transparency.[45] Some stakeholders suggested that some level of generator bidding behaviour could be modelled, which would result in generator bids diverging from SRMC.

3.3.2 Draft decision

The draft methodology applies electricity market modelling to estimate CECVs (using PLEXOS). Although we note the potential drawbacks of this approach, including the need for agreement on inputs and lack of transparency, we consider these can be overcome by simplifying the modelling process. Importantly, we consider that electricity market modelling will provide a greater degree of accuracy in CECV estimates.

The draft methodology estimates the DER value streams in the following ways:

- DER export displaces the need for utility-scale generation and generally reduces the system-wide dispatch cost of meeting energy demand. Our electricity market modelling simulates the dispatch procedure of the NEM to estimate the marginal value of customer exports, which is equal to the marginal value of reducing operational demand. For example, if a DNSP's proposed investment increases DER exports by 1 MWh (reduces operational demand by 1 MWh) relative to the 'expected scenario' or outcome, the CECV will capture the total NEM-wide benefit of the investment. Our 'expected scenario' for our initial estimation of CECVs is the 'Step Change' scenario set out in AEMO's Draft 2022 Integrated System Plan.[46] This scenario is considered by energy industry stakeholders to be the most likely future scenario to play out. During low operational demand periods, additional DER export could also add cost to wholesale system costs if the minimum generation level constraints of thermal units are binding. The model captures this by effectively bidding the minimum generation level of coal plants at the market price floor. Given this, the model will charge battery and pumped hydro during low demand or high renewable output periods to alleviate minimum generation level constraints.

[45] AusNet Services, 'Submission to the customer export curtailment value methodology', December 2021.

[46] AEMO, 'Draft 2022 Integrated System Plan for the National Electricity Market', December 2021.

- For FCAS services, the modelling process described above approximates the impact of the eight FCAS services[47] by applying a single value for headroom (which represents a unit generating below its maximum available capacity in order to be able to provide raise FCAS), and a single value for footroom (which represents a unit generating above its minimum generation level in order to be able to provide lower FCAS).[48]
- Transmission and distribution losses from generation to the regional reference node are captured in the modelling process, with the marginal production costs incorporating these losses. DNSPs will separately be able to enter transmission and distribution loss factors as inputs to the DNSP Model (discussed in section 4) that are relevant to each proposed project.

Model inputs

Model inputs and sources are provided in Table 3.1. Oakley Greenwood provides a further discussion on the model inputs and the drivers of modelling results, including fuel prices and time-of-day system demand shape.[49]

Table 3.1: Model inputs

Input	Source
Existing and committed unit capacity	Draft ISP 2022 assumptions (2021 IASR)[50]
Existing and new generator operating characteristics	Draft ISP 2022 Step Change (2021 IASR)[51]
Intra- and inter-regional transmission capacity	Draft ISP 2022 Step Change modelling output including the Optimal Development Path for transmission expansion
Demand, wind and solar traces	Draft ISP 2022 Step Change (2021 IASR), ESOO and ISP traces
Fuel prices	Draft ISP 2022 Step Change (2021 IASR)

Modelling process

The dispatch model runs for twenty years, with the initial model run from FY 2022-23 to FY 2041-42. The model is dispatched at half-hourly granularity using an algorithm that is similar to AEMO's real-time dispatch engine (NEMDE).[52] Consistent with modelling practices, the algorithm is appropriately adapted to ensure storage and other energy constraints (such as

[47] Three contingency raise services (6s, 60s, 5min), three contingency lower services (6s, 60s, 5 min), and one regulation raise service and one regulation lower service.

[48] Specifically, we applied a NEM-wide headroom requirement of 944 MW (equal to the largest generating unit plus the associated raise regulation requirement) and a NEM-wide footroom requirement of 570 MW (equal to the largest load plus the associated lower regulation requirement).

[49] Oakley Greenwood, CECV Methodology – Interim Report, 6 April 2022.

[50] AEMO, '2021 Inputs and assumptions workbook' , December 2021.

[51] The model uses the ISP's Step Change coal retirement path but also accounts for the NSW coal retirement announcement in February 2022. That is, all Eraring units are assumed to retire from FY 2024-25 and all Bayswater units are assumed to close from FY 2032-33.

[52] Although it may be possible to run the model at 5-minute granularity, it would require re-estimating AEMO forecasts at a more granular level and would only be practical for DNSPs if they intend to estimate alleviation profiles at 5-minute granularity.

hydro) are dispatched to minimise total system cost (including FCAS) for each modelled year.

A single simulation is undertaken using POE50 demand traces.[53] Oakley Greenwood noted that given this modelling project is resource cost-based, using a weighted average between POE10 and 50 demand will not significantly alter the marginal cost of CECV. The impact of POE10 demand will be further diluted to the extent that the half-hourly CECVs are further aggregated into less granular time slices to facilitate use of the data by DNSPs.[54]

Forced outage is modelled using average expected forced outage rates (EFOR). This approach is preferred to one that applies randomised forced outages at the individual unit level, as this would potentially require running hundreds of simulations with different forced outage traces.

The reference year of FY 2018-19 used for the demand, wind and solar traces, as at the time of modelling, this is the most recent reference year with complete traces for modelled existing, committed and new entrant variable renewable energy (wind and solar) plants.

Since the model is resource cost-based, we have not considered different generator bidding behaviours or strategies.

Model outputs

The result of this modelling process is a schedule of marginal export values (CECVs) for each NEM region for every half-hour over the next 20 years (with the initial values commencing in 2021-22). These values are the marginal value of reducing operational demand (the shadow price of regional demand-supply constraint).

In the next section we provide the rationale for the DNSP model. This model provides options for aggregating the large number of marginal export values depending on the DNSP's proposed investment and the curtailment alleviation profile it will provide.

Question 6: Do you have any views on the model inputs and assumptions and the process of estimating CECVs?

3.4 Annual updates

Prior to 1 July each year we will consider whether input assumptions under the ISP's Step change scenario have materially changed to reflect new information or forecasts. For example, there may be new assumptions in the final version of the ISP, and then further updates to assumptions or scenarios in later years.

[53] POE refers to probability of exceedance. A POE is generally organised in a distribution curve and uses 90, 50 and 10 marker values to present and measure data. The POE50 represents the average, or middle value, in any range of measurement and is the most likely to occur. This means 90% of the data will be greater than the POE90 marker and only 10% of the measured data will be higher than the POE10 marker.

[54] Oakley Greenwood, CECV Methodology – Interim Report, 6 April 2022.

- If there are material changes, we will re-estimate CECVs using the new assumptions, update these values in the DNSP model and make subsequent changes to the number and nature of characteristic days in the DNSP model.
- If there are no material changes, we will only update CECV estimates to account for changes in inflation, to ensure that in economic terms, real values of CECV are maintained between CECV reviews. Instead of estimating new values for the 20th year of the analysis period, we will calculate new values based on the terminal value methodology discussed in section 4.2.1 (with the average of the final three years of values used as the new value for each half-hourly interval).

New CECV estimates will be published by 1 July each year.

3.5 Reviewing the methodology

We must, at least once every five years, review the CECV methodology and following such review, publish either an updated CECV methodology or a notice stating that the existing CECV methodology was not varied as a result of the review.[55]

Our initial view is that we will review the CECV methodology prior to the five-yearly review if there is new information to support either:

- the inclusion of new wholesale market value streams in the methodology (for example, if there is analysis to suggest that the avoided generation capacity investment value stream is material and can be estimated objectively); or
- adopting a new approach to quantifying wholesale market value streams, which may include both shorthand and longhand approaches.

Oakley Greenwood also suggested that we consider monitoring the development of the FCAS markets in the next few years to assess whether a more detailed representation of FCAS (and potential new ESS markets) should be adopted in future assessments. Some of the key areas of development that might increase the ESS service participation by DER include:

- new ESS such as Fast Frequency Response markets (which will commence in October 2023) and potential new services such as Inertia (currently under a rule change), and
- new technological and regulatory development that might facilitate participation of DER such as Dynamic operating envelope, EVs and home energy storage.[56]

Question 7: Do you have any views on the factors we should consider in updating CECVs annually, as well as potential triggers for reviewing the CECV methodology prior to the five-yearly review?

[55] NER rule 8.13(f).

[56] Oakley Greenwood, CECV Methodology – Interim Report, 6 April 2022.

4 Application of CECV

As discussed in section 1, CECVs will help guide the efficient levels of network expenditure for the provision of export services and serve as an input into network planning, investment and incentive arrangements for export services. CECVs will represent the benefit to all customers from the alleviation of curtailment, which allows a greater level of DER exports (the CECVs multiplied by the additional electricity provided by DER exports equals the total benefit). DNSPs are also permitted to quantify other DER value streams not captured by the CECV methodology and compare total benefits against costs in their cost-benefit analyses.

Noting that the process of estimating CECVs results in a schedule of marginal export values CECVs for every half-hour over the next 20 years, it will be labour-intensive for DNSPs to attribute these values according to their proposed network solutions over the economic life of each investment.

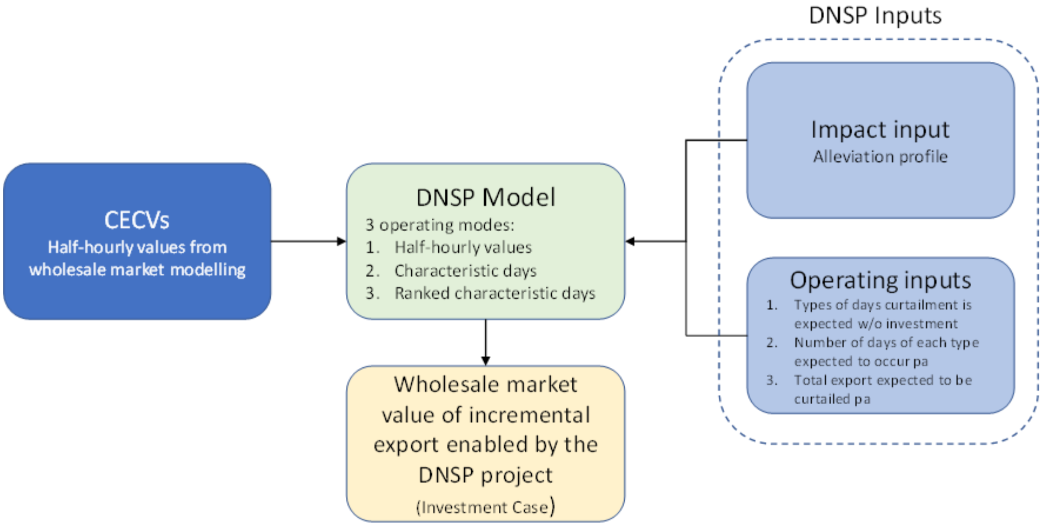
In this section we provide an extension to the CECV methodology—the methodology used to estimate CECVs—and discuss possible options for DNSPs to apply CECVs in practice. We introduce a model developed for DNSPs to easily aggregate the estimated CECVs and quantify the contribution of CECVs to the overall benefit of proposed DER integration investments. We seek stakeholder views on the applicability of the model in general, as well as specific characteristics of the model.

4.1 Overview of the DNSP model

The DNSP model will serve two purposes:

- Allow DNSPs to estimate the CECV that is provided by a proposed network investment that increases the amount of hosting capacity on their network; and
- Assist the AER to review the key inputs that DNSPs use to support the business case for their proposed network investments.

Figure 4.1: Overview of DNSP model



Source: Oakley Greenwood

4.1.1 DNSP model inputs

CECVs

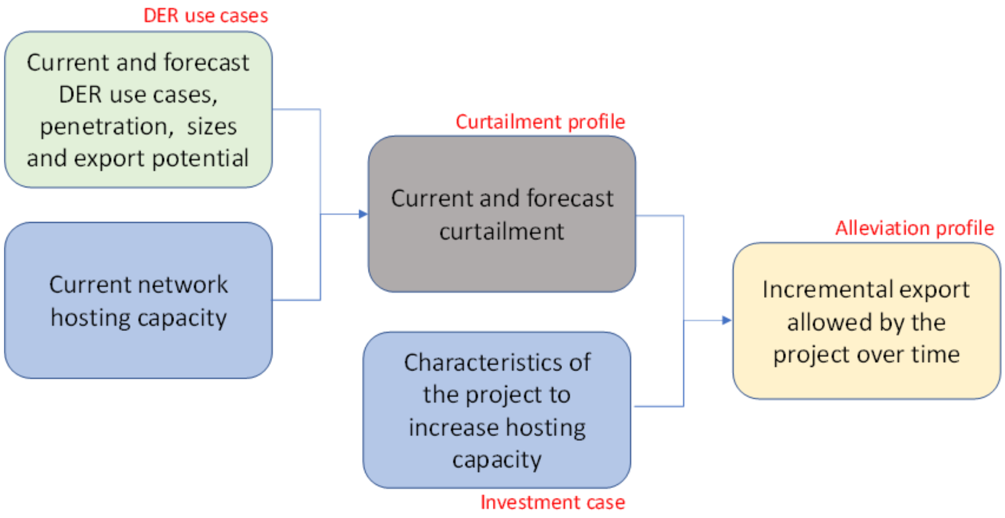
The CECVs are the raw, half-hourly values estimated over a 20-year period, as per the CECV methodology.

Impact input: the alleviation profile

In section 2 we introduced the concept of the alleviation profile. The alleviation profile provides the amount and timing of additional electricity that can be exported to the grid due to the proposed investment to increase hosting capacity.

A key feature of an alleviation profile is that it reflects some time differentiation, which could be season, time of day or broader supply/demand conditions, and also considers changes in DER penetration over time. Figure 4.2 summarises the factors a DNSP is likely to consider in estimating an alleviation profile for each investment case.

Figure 4.2: Factors to consider in developing the alleviation profile



Source: Oakley Greenwood

Table 4.1 summarises the factors that are likely to determine the alleviation profile for a proposed investment to increase hosting capacity.

Table 4.1: Factors likely to determine the alleviation profile

Factor	How it affects the proposed alleviation profile
Current and forecast DER penetration, sizes and potential (unconstrained) export (DER use cases)	Existing DER penetration will affect the existing level of headroom available within the network for the export of DER. The forecast penetration of additional DER (and the size of these systems) will likely be a key determinant of how quickly (and the specific times at which) any existing headroom will be used up, thereby influencing the amount and timing in which curtailment would be expected to be needed, absent any investment by the DNSP to increase hosting capacity. For example, the forecast number of behind the meter (BTM) batteries (and how they are operated) will likely influence the amount of solar that, absent any network constraints, would be generated and available, net of the host facility's electricity needs, to be exported to the grid.
New and evolving tariffs and price signals	Solar sponge tariffs and/or two-way pricing or other price signals to be introduced over the analysis horizon could reduce the need to curtail energy by incentivising more internal consumption or less export during periods where curtailment may otherwise have been required. Such developments should be taken into account in the development of the expected alleviation profile.
Current network hosting capacity	The amount of export that can be accommodated in each specific part of the network will be limited by the capacity of the local network and available controls. That amount will vary over time based on the amount of electricity that is trying to be exported and other aspects of the electrical environment in the area, such as voltage levels and the location at which the export is seeking to access the network.
Curtailment profile	This is the amount and timing of the curtailment that would be expected to occur based on the current hosting capacity in the network and the export potential of existing and forecast DER systems.
Characteristics of the project being proposed to increase hosting capacity (investment case)	The nature of the project and operating practices being proposed by the DNSP will likely determine how much of the export that could be made available by existing and forecast DER systems will be able to be exported and how much may still have to be curtailed. For example, if the project results in the inherent export capacity of a part of the network increasing from 5kW to 7kW, curtailment may still be needed at those times when the average export available exceeds 7kW. The alleviation profile should consider situations in which the additional hosting capacity may not be sufficient to accommodate all available export.

Source: Oakley Greenwood

Operating inputs

DNSPs are also required to enter operating inputs, depending on their approach to using the model. These inputs are derived from the DNSP's assessment of hosting capacity and the expected outcomes of its proposed network investment. This includes the types of days when export curtailment is occurring, the number of days that export curtailment is occurring and the estimated volume of electricity from DER export that is being curtailed (absent the proposed investment).

4.1.2 DER use cases

Different configurations of DER will have different implications for the development of an alleviation profile, with different types of DER exporting different volumes of electricity to the network at different times. The DNSP model is suited to the analysis of DER exports that are not readily controlled, such as rooftop PV and BTM battery storage systems without communications and controls. The impact of network actions to accommodate DER exports from these types of DER can be reasonably estimated, as the timing of these exports is based on foreseeable conditions such as solar irradiance and local demand.

4.2 Using the DNSP model

The CECV methodology provides three possible approaches for DNSPs to aggregate CECVs to support the development of a business case. These include:

- self-selection of half-hourly values;
- identifying “characteristic days” when DER export curtailment is likely to be relieved by the proposed investment, along with the additional volume of electricity to be provided by DER exports for each type of day; and
- identifying the number of days when DER export curtailment is likely to be relieved by the proposed investment, along with the additional volume of electricity to be provided by DER exports.

In the following sections we discuss the pros and cons of each approach and seek stakeholder views.

4.2.1 Self-selection of half-hourly values

As detailed in section 3, we provide a set of half-hourly CECVs for each year in the analysis timeframe (20 years) for each NEM region. The DNSP is required to enter, for each half hour, the quantum of additional export enabled by the proposed investment. The model then multiplies that quantum of additional export by the CECV for that half hour to estimate the total benefit attributable to the CECV.

If the proposed project’s life exceeds 20 years, the model calculates a terminal value based on the following assumptions:

- the average of the final three years of market values available in the model are used as values that will apply for any period beyond the 20th year; and
- the alleviation profile to apply for any period beyond the 20th year is the profile inputted by the DNSP in the 20th year.

The advantage of the self-selection approach is that it provides DNSPs with the flexibility to develop their own alleviation profile. It also does not require any material post-processing of the wholesale market modelling outputs. The disadvantage of this approach is that it is labour-intensive for the DNSP to develop a detailed alleviation profile by half-hour for the entire analysis horizon (which may be 15-20 years). It is also labour intensive for the AER to review the robustness of the alleviation profile submitted by the DNSP. Finally, this approach does not provide DNSPs with the factors that drove the CECVs, and therefore there is potential for misalignment between the DNSP’s alleviation profile and the estimated values.

Question 8: Do you support the DNSP model allowing for the self-selection approach?

4.2.2 Set of characteristic day types

Under this approach the model averages and aggregates CECVs across a set of ‘characteristic day’ types (and hours within those days) that constitute when curtailment is likely to occur absent any investment to increase hosting capacity (for example, during spring when there is low electricity demand, high solar PV output).

Characteristic days[57] reflect two parameters that are identifiable in the PLEXOS modelling and that are considered most likely to affect the alleviation profile:

- The level of demand at a regional level (as a proxy for the relative demand at the specific location of the proposed project), and
- The level of behind the meter solar PV generation at a regional level (as a proxy for the estimated level of production of behind the meter solar PV at the specific location of the proposed project).

Under this approach the DNSP inputs the additional volume of electricity (kWh) provided by the proposed investment (per annum) for each characteristic day type.

Table 4.2 provides potential characteristic days and illustrates the concept of aggregating CECVs across characteristic days.

Table 4.2: Types of characteristic days

Characteristic day (TBC)	Aggregated PLEXOS outputs	
	# days	Average marginal wholesale cost ($/MWh)
High underlying demand (POE10) / High solar PV generation (90th percentile)	*TBC*	*TBC*
High underlying demand (POE10) / Medium solar PV generation (50th percentile)	*TBC*	*TBC*
High underlying demand (POE10) / Low solar PV generation (10th percentile)	*TBC*	*TBC*
Medium underlying demand (POE50) / High solar PV generation (90th percentile)	*TBC*	*TBC*
Medium underlying demand (POE50) / Medium solar PV generation (50th percentile)	*TBC*	*TBC*
Medium underlying demand (POE50) / Low solar PV generation (10th percentile)	*TBC*	*TBC*
Low underlying demand (POE90) / High solar PV generation (90th percentile)	*TBC*	*TBC*
Low underlying demand (POE90) / Medium solar PV generation (50th percentile)	*TBC*	*TBC*
Low underlying demand (POE90) / Low solar PV generation (10th percentile)	*TBC*	*TBC*

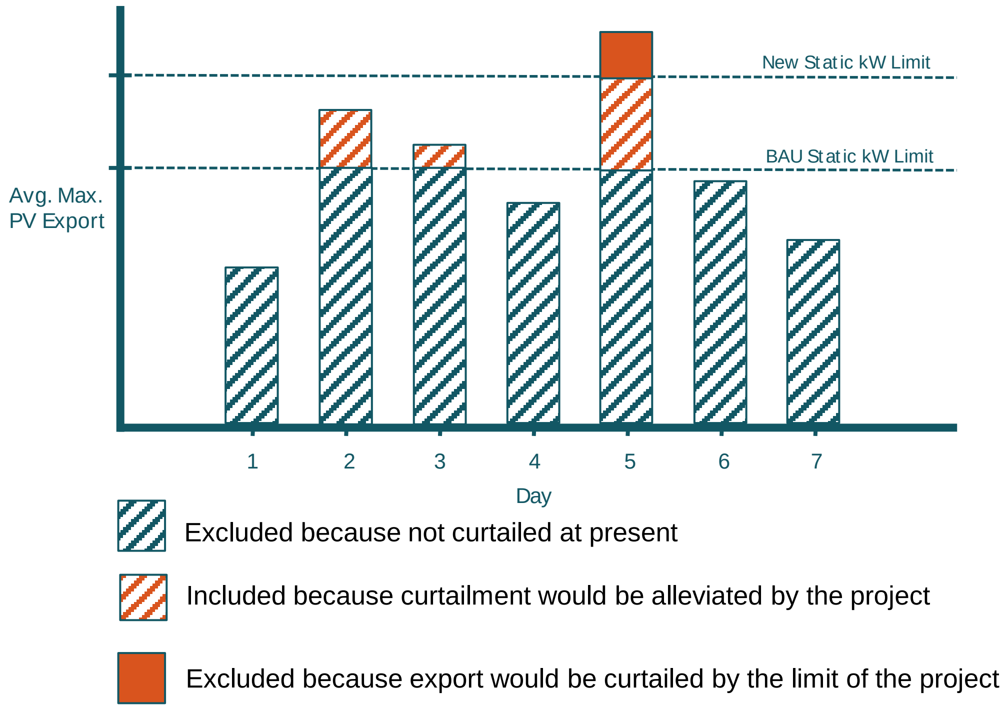
Characteristic day information will be categorised by:

- NEM region
- Year
- Season

[57] Note that characteristic day types are to be confirmed and are subject to stakeholder feedback.

- Time of day when solar curtailment will generally occur (e.g., 12pm to 3.30pm)[58]
- Static limits on PV export (e.g., 5kW, 4kW, 3kW), the effect of which would be to exclude all days where the maximum rooftop solar PV production (in the market modelling) does not reach that limit (e.g., the 5kW results will already exclude all days/results where the maximum average solar PV production on the day is less than 5kW). Figure 4.3 illustrates this concept.

Figure 4.3: Modelling of additional export above an existing static export limit



Source: Oakley Greenwood

Example of characteristic day concept

Proposed project seeking to remove a 5kW static limit on solar export

- The DNSP would select the CECVs for a 5kW static limit from a menu in the model. This would automatically select data that already excludes all days where the maximum PV production does not reach that limit (because removing the static limit will not affect export on those days).
- The DNSP would then input, for each year, their estimate of the additional energy released, by each type of characteristic day (e.g., low demand / high PV production spring day).
- The model will then calculate the estimated value of that additional energy based on the kWh the DNSP has attributed to that characteristic day multiplied by the average wholesale value for that characteristic day (during the half-hour periods where curtailment is likely to happen).

[58] Meaning that CECVs outside this period will be excluded from the characteristic day analysis.

- In developing the amount of export to be enabled on a particular characteristic day in each year of the analysis horizon (for input into column e in the table above) the DNSP will need to be mindful of how additional DER penetration may result in curtailment spreading from one to a second (or third) type of characteristic day.

The advantage of the characteristic day approach is that the aggregation of raw modelling outputs makes it easier for DNSPs to conceptualise the impact of their proposed investment, as this only needs to be done for each type of characteristic day (instead of half-hourly). It also means that CECVs are better aligned with the DNSP's alleviation profile, which makes it more intuitive for stakeholders, including customers, and provides the AER with a simpler process of reviewing model inputs. This approach still requires DNSPs to make a judgement about the additional volume of electricity to be provided by the proposed investment across the characteristic days, which may require a material amount of judgement.

Oakley Greenwood's report provides further examples to demonstrate the concept of characteristic days and the differences in aggregated CECVs across characteristic days.[59]

Question 9: Do you support the DNSP model allowing for the characteristic day approach?

4.2.3 Ranking characteristic day types

Under this approach we build upon the previous approach by ranking days in order of when export curtailment is most likely to occur. For example, if we think that export curtailment is most likely to occur on low electricity demand, high solar PV generation days in springtime, that type of day is ranked #1. Rankings of characteristic days are pre-set in the DNSP model based on the factors likely to drive curtailment.[60]

The DNSP is required to input the number of days (per annum) when DER export curtailment is likely to be relieved by the proposed investment, along with the additional volume of electricity to be provided by DER exports (per annum).

The model then automatically attributes the forecast of additional DER exports to the characteristic days based on the rank of day and the number of those characteristic days identified in the PLEXOS modelling.

The value of curtailment relief stemming from the network investment is equal to sum of the energy allocated to each characteristic day multiplied by the average CECV for that day.

[59] Oakley Greenwood, CECV Methodology – Interim Report (Appendix A), 6 April 2022.

[60] Note that rankings are to be confirmed and are subject to stakeholder feedback.

Example of the ranked characteristic day concept

DNSP proposes investment to reduce export curtailment due to voltage issues

- The DNSP estimates the daily maximum solar PV generation level below which export curtailment is unlikely to occur in a year (absent investment). For example, if maximum solar PV generation is less than 3kW.
- The model selects CECVs to correspond with the DNSP's estimate. In this example, inputs greater than 3kW are selected.
- The DNSP inputs (for each year) the total estimated additional electricity provided by the proposed investment (e.g., 100,000 kWh) and the number of days when export curtailment would have likely occurred (e.g., 25 days).
- The model matches the 25 days to the occurrences of ranked characteristic days. For example, the first ranked day: "Low underlying demand (POE90) / High solar PV generation (90th percentile)" has 10 occurrences in the PLEXOS data, and the second ranked day "Low underlying demand (POE90) / Medium solar PV generation (50th percentile)" has 15 occurrences in the PLEXOS data.
- The model allocates the additional electricity provided by the investment (100,000 kWh) to the days (as opposed to the DNSP doing this under the previous approach) and estimates an overall value. For example,
  - Rank #1 day: 10/25 x 100,000 kWh x average CECV for Rank #1 type day
  - Rank #2 day: 15/25 x 100,000 kWh x average CECV for Rank #2 type day

The added benefit of this approach is that the types of days when DER export curtailment is most likely to occur are set in advance, and DNSPs are only required to estimate the number of days where curtailment would have otherwise occurred, and the additional volume of export provided by the proposed investment. DNSPs also have the ability to re-rank the characteristic days if it is justifiable.

The disadvantages of this approach are that it provides the DNSP with less flexibility in defining the alleviation profile, and still requires the DNSP to apply judgement in estimating the number of curtailment days. Further judgement is also required if the DNSP elects to re-rank the characteristic days (and also for the AER to assess the re-ranking).

Question 10: Do you support the DNSP model allowing for the ranking of characteristic days approach?

Question 11: Do you have views on the ranking of characteristic days?

Appendix A: Stakeholder submissions

ID	Theme	Stakeholder	Comment	Response
1.1	Export curtailment	Ausgrid	AEMO ISP assumptions and scenarios should be used as the basis to develop CECVs. The AER should adopt more nuanced localised CECVs and allow DNSPs to put forward localised CECVs where data allows.	The AEMO Draft ISP 2022 Step Change scenario is used as the basis to develop CECVs. We do not consider it practical to estimate (or allow DNSPs to estimate) localised CECVs. CECVs are estimated by NEM region to reflect the nature of the wholesale market.
1.2	Export curtailment	AusNet Services	Curtailment should be considered a scenario where a lower level of DER export occurs relative to an expected level. Appropriately defining those scenarios will, therefore, be a key challenge of the CECV methodology. DNSPs should have the flexibility to select the input assumptions they consider most appropriate. The default position should be that those inputs are deemed reasonable unless demonstrated to be otherwise.	We do not agree that DNSPs should have the flexibility to select input assumptions. The methodology should be applied consistently across all DNSPs, and it is reasonable to adopt the AEMO Draft ISP 2022 Step change scenario.
1.3	Export curtailment	Consumer Challenge Panel	The AER should be more explicit in what is meant by curtailment - is it related to long-term fundamental network hosting capacity (such as non-coincident maximum demand), or is it a much more dynamic, time varying value that reflects local network conditions, demand and generation diversity, inbuilt control mechanisms and customer self-consumption incentives?	In section 1 we note that under the new rule, customer export curtailment means reducing, tripping or otherwise limiting customer export.
1.4	Export curtailment	Energy Queensland	The AER should consider differing values for the CECV depending on the type of curtailment (for instance, whether the curtailment is the result of a reduced export capability or whether it is the lost value where a generation system is required to be zero export due to a network outage or other system event).	CECVs will reflect the marginal export value (which also captures FCAS-related cost impacts). It will be up to DNSPs to aggregate CECVs according to a profile of curtailment alleviation (see section 4).
1.5	Export curtailment	Jemena	The AER's interpretation of export curtailment is too narrow. Export constraints are broader than just voltage issues. System security and minimum demand concerns could cause DNSPs to curtail customer exports. Ignoring these network features could potentially understate the total volume of expected constrained exports, which would weaken DER integration investment cases.	We recognise that the interpretation provided in the issues paper was too narrow. See response to 1.3.
1.6	Export curtailment	Public Interest Advocacy Centre	Concerned with the AER's initial view they do not need to identify instances of curtailment and estimate the impacts on specific customers to calculate CECVs. While PIAC understands the rationale for this approach, it is likely to be inaccurate. The AER should work towards gathering evidence of actual	Export curtailment is difficult to objectively measure because it can occur due to a number of reasons (e.g., weather conditions, electricity use, equipment faults, installation faults). Furthermore, there is no common approach to assessing network hosting capacity, with DNSPs often relying on

ID	Theme	Stakeholder	Comment	Response
			curtailment from distributors to develop more accuracy. Is the AER able to provide more explanation of why 'export curtailment is difficult to objectively measure'? Is it difficult to measure because DNSPs currently do not have the capability to measure it? Could DNSPs develop the capability to measure export curtailment?	'rule of thumb' or sampling approaches to estimate available hosting capacity. In proposing a DER integration investment, DNSPs will assess network hosting capacity and identify that it is limited (and therefore export curtailment is occurring or will occur in the future). For the purpose of the CECV methodology, we do not need to identify instances of export curtailment. Instead, the methodology estimates the value (in terms of wholesale market value streams) of relieving export curtailment. It is then up to DNSPs to identify an export curtailment alleviation profile and aggregate CECVs accordingly.
2.1	DER value streams	Australian Energy Council	The value streams that should be captured in the CECV fit into two groups: those that are able to be independently estimated (wholesale energy market, environmental values, social values) and those relying on DNSP estimates (avoided costs of investment).	We consider that since some DER value streams are specific to DNSPs (for example network sector value streams, which rely on DNSP estimates), they should not be included in the CECV but instead be estimated separately by the DNSP.
2.2	DER value streams	Ausgrid	CECVs should reflect all wholesale market value streams, including the avoided marginal generator SRMC, the avoided generation capacity investment and essential system services. There are modelling complexities associated with modelling avoided generation capacity investment and ESS value streams. However, these values are critical to setting efficient signals so that CECVs reflect the true opportunity cost of curtailing exports. Ausgrid has engaged in a joint consultancy with other DNSPs which will calculate how CECVs can incorporate avoided capacity investment and ESS.	The CECV methodology estimates energy related dispatch cost and also captures the FCAS-related resource cost impact by DER export. Estimating the avoided generation capacity investment component is complex and would require further assumptions about the alleviation profiles provided by DNSP investments. Since we do not have this information, we consider it sensible to exclude this component from the methodology. However, DNSPs are not precluded from estimating this value stream separately as part of their expenditure proposal.
2.3	DER value streams	Ausgrid	Customer preferences should determine the value of DER investment and these preferences should be reflected in the benefit streams. Tangible environmental benefits should also be reflected in the valuation of DER investments.	The VaDER methodology study and our draft DER integration expenditure guidance note outline the DER value streams. This includes environmental costs and benefits where they impart a direct cost or benefit on the electricity system. For example, if a carbon price existed it would be reflected in generator operating costs and captured in our estimation of CECVs.
2.4	DER value streams	Consumer Challenge Panel	When considering the value stack, the AER could prioritise value streams by considering how much uncertainty is associated with each stream and whether the benefits delivered by the value stream are realised immediately or may take time to be realised. This would help ensure the methodology is in line with standard assumptions made about consumer risk preferences and a	We will consider this feedback when finalising the DER integration expenditure guidance note.

ID	Theme	Stakeholder	Comment	Response
			tendency to discount benefits and costs that are realised in more distant periods (standard in cost benefit analysis).	
2.5	DER value streams	Consumer Challenge Panel	The AER should consider estimating separate CECVs for (1) rooftop solar, (2) batteries, (3) EVs and (4) energy management systems.	CECVs will be used to (partly) value investments which lead to increased levels of DER exports. It will be up to DNSPs to demonstrate that the investment will lead to more rooftop solar, batteries or other types of DER, and in doing this they should demonstrate that the aggregation of CECVs reflect the appropriate export curtailment alleviation profile, as discussed in section 4. CECVs are estimated based on a process of wholesale market modelling (discussed in section 3), and values are reflective of the time-varying nature of DER exports that different types of DER provided to the wholesale market.
2.6	DER value streams	CitiPower, Powercor & United Energy	Do not agree that the scope of the CECV should be limited to estimating dispatch costs, and instead the AER should take a more holistic approach to understanding and quantifying customer value of export curtailment by incorporating the intrinsic customer value of choice and control of enabling exports and the customer value of environmental benefits of enabling exports.	The VaDER methodology study and our draft DER integration expenditure guidance note outline the DER value streams. Wider societal costs and benefits are not included as DER value streams as the costs and benefits accrue to parties outside the electricity system.
2.7	DER value streams	Endeavour Energy	Concern that only looking at avoided marginal generator SRMC will lead to CECVs being understated. Expect that avoided generation capacity investment will be increasingly important to consider as battery storage and other large-scale renewable generation increasingly become marginal. Consequently, the appropriateness of relying on avoided dispatch costs as the proxy for CECVs may diminish over time.	See response to 2.2.
2.8	DER value streams	Endeavour Energy	CECVs should also capture intangible customer benefits such as avoided greenhouse gas emissions, improved customer empowerment and choice etc.	See response to 2.6.
2.9	DER value streams	Essential Energy	If CECVs are to only focus on wholesale market value streams, DNSPs should be permitted to consider all other value streams in their proposals. Following which, DNSPs can analyse and test with customers their willingness to pay for additional higher levels of DER hosting capacity.	Under our DER integration expenditure guidance note, DNSPs will be permitted to estimate other, network specific, value streams and quantify them using the suggested methods (for example, avoided network investment). As noted in section 2, we are considering DER value streams that transfer benefits to electricity consumers in the long-term and increase consumer and producer surplus. We do not consider that a DER owner’s willingness to pay a premium for DER is an electricity consumer

ID	Theme	Stakeholder	Comment	Response
				surplus, or that intangible benefits represent a producer surplus (where a DER owner makes a loss on their investment).
2.10	DER value streams	Jemena	Agree that CECVs should capture the wholesale market costs and benefits to end-users, as measured by changes in generator dispatch costs. CECVs should also capture the economic value of line losses that would be avoided by relying on DER generation rather than more traditional forms of centralised wholesale generation.	Transmission and distribution losses from generation to the regional reference node are captured in the modelling process, with the marginal production costs incorporating these losses. DNSPs will separately be able to enter transmission and distribution loss factors (as inputs to the DNSP Model) that are relevant to each proposed project.
2.11	DER value streams	SA Power Networks	For the DER value stream “change in DER investment”, the AER should confirm SAPN's understanding that these costs would only be required to be included in valuation if a distributor was proposing to alter its DER penetration forecasts between its base case and its network investment case.	Yes, this is our position made in the draft DER integration expenditure guidance note. We recognise the practical challenges in estimating these costs/benefits, however, expect that DNSPs will rarely alter DNSP penetration forecasts between the base case and investment case.
2.12	DER value streams	TasNetworks	In Tasmania, where the marginal generator is often hydro, the avoided SRMC is likely to materially understate the wholesale market benefits of increasing DER hosting capacity. Wholesale market benefits will arise through hydro becoming available at different times of day, particularly during Tasmania's dry summer period, reducing the need for investment in generation to meet peak demand. Similarly, enabling hydro generation at peak times will indirectly avoid fuel costs of more expensive generation.	See response to 2.2.
2.13	DER value streams	TasNetworks	It will be costly and inefficient for DNSPs to calculate avoided generation investment costs separately for each DER integration investment proposal. It may also lead to inconsistencies in how wholesale market benefits are calculated. Therefore, the CECV methodology should be robust enough to capture both avoided SRMC and avoided generation investment. This can be achieved by using electricity market modelling.	See response to 2.2. Although this approach may lead to inconsistencies in the calculation of avoided generation capacity investment costs, this value stream is necessarily different across DNSPs as they will propose different types of investments which provide different export curtailment alleviation profiles.
3.1	Different CECVs for particular customer groups	Australian Energy Council	Support the principle of cost reflective pricing, and therefore an approach that reflects the detriment from DER curtailment to customer classes is preferred.	Under the CECV methodology CECVs reflect the detriment to all customers, as both DER and non-DER customers are impacted by DER export curtailment and the relief of export curtailment. As noted in section 2.3.2, the common distribution service is classified as a SCS under our Distribution Service Classification Guideline because all customers benefit from the service. If the export service is classified as a SCS, the relevant benefit streams are

ID	Theme	Stakeholder	Comment	Response
				those that provide benefit to all customers. Although there is a relationship between CECVs and export tariffs, it is not a direct one. Our export tariff guidelines set out how DNSPs should propose export tariffs in their tariff structure statements. In developing two-way pricing proposals, DNSPs should consider the long run marginal cost and efficient cost pricing principles together.
3.2	Different CECVs for particular customer groups	Ausgrid	CECVs should be specific to network customer groups. These targeted CECVs will allow for more accurate valuations of the impact of curtailment by electricity distributors. However, specific CECVs are not necessary to inform developing export tariffs which will continue to be developed based on LRMC.	See response to 3.1. In addition to not being necessary to inform the development of export tariffs, customer specific CECVs are also not necessary for the purpose of investment planning and quantifying benefits.
3.3	Different CECVs for particular customer groups	AGL	Estimating CECVs across different customer groups could entail regional or nodal based analysis by reference to local DER export intensity.	See responses to 3.1 and 3.2.
3.4	Different CECVs for particular customer groups	AGL	CECVs should contemplate the detriment to all customers and separately to DER exporters, given that DER customers will experience different benefits because of their ability to engage with the energy market system through orchestration services.	While we agree that DER and non-DER customers will experience different benefits, for the purpose of investment planning it is only necessary for networks to demonstrate an overall benefit to customers.
3.5	Different CECVs for particular customer groups	Consumer Challenge Panel	Agree that over the long term all customers benefit from reduced curtailment of DER, but the benefits in lower bills will be subject to many variables such as new market costs to maintain a stable and reliable electricity supply, the diversity in energy utilisation across many customer cohorts and the relative infrequency and extent of curtailment. It is appropriate that CECVs are considered separately for prosumers (DER customer) and non-DER customers, as the impacts are quite different.	We recognise that the impacts of more or less DER exports are different for DER customers and non-DER customers. However, assuming that the export service is classified as a standard control service, separate CECVs are not required for DNSPs to justify investments.
3.6	Different CECVs for particular customer groups	Consumer Challenge Panel	Do not believe that prosumers should be considered in the aggregated calculation of CECV in a business case, as they are much less exposed to wholesale price issues. The AER should consider investigating further how export curtailment may impact DER investment decisions by rooftop solar PV customers to accurately assess the short run and long run costs (and potential benefits) of curtailment of exports. This will help ensure CECV methodology is not focused on a short run interpretation of	The change in customer investment in DER is an accepted value stream under our DER integration expenditure guidance note, however, is not related to the wholesale market and so is excluded from the CECV methodology. For the purpose of investment planning, it is not necessary to consider differences in CECVs across customer groups. Therefore, a willingness-to-pay approach to estimating CECVs is not necessary.

ID	Theme	Stakeholder	Comment	Response
			customer costs, but also consider long run substitution effects and price elasticity on the demand side. Support the idea that the VCR methodology based on willingness-to-pay and choice modelling is a good starting point to considering how CECVs vary across customer groups.	
3.7	Different CECVs for particular customer groups	CitiPower, Powercor & United Energy	If the AER extended the scope of the CECV to include broader customer values, there would be merit in exploring the differences in value of export curtailment between DER and non-DER customers and residential versus non-residential. If the AER does not factor broader customer values into the CECV, the AER should explicitly state that it will allow networks to add broader customer values into the benefits case for proposed investments and incentives schemes relating to export services. This supports the role of customer engagement and customer-centric decision making, consistent with the spirit of the AER's Better Resets Handbook.	The CECV methodology is limited to wholesale market value streams as these can be estimated consistently across NEM regions. It does not consider broader customer values. The VaDER methodology study and our draft DER integration expenditure guidance note outline the DER value streams we will consider. Other customer values may be considered provided they are quantifiable, robust and accrue to consumers or producers of electricity.
3.8	Different CECVs for particular customer groups	Energy Queensland	The CECV should contain a mixture of detriments to all customers (as a net market benefit) as well as for particular types of customers, such as those with export capability. This should be viewed in combination with the detriment to all customers that comes from limiting export and the associated wholesale market cost increases.	See responses to 3.1 and 3.2. For the purpose of investment planning, it is not necessary to consider differences in CECVs across customer groups.
3.9	Different CECVs for particular customer groups	Energy Queensland	Suggest a similar approach to the methodology for calculating VCRs (through willingness to pay surveys). Further, as per the VCR categorisation, it would seem reasonable to calculate CECVs in different climate zones.	For the purpose of investment planning, it is not necessary to consider differences in CECVs across customer groups. Therefore, a willingness-to-pay approach to estimating CECVs is not necessary.
4.1	Expression of CECVs	Australian Energy Council	Support an approach whereby intra-regional CECVs are expressed as $ per MWh of curtailed solar PV generation. In practice this will require additional intra-regional locational costs (as opposed to NEM region costs) in the calculation of wholesale market costs.	CECVs estimated under the CECV methodology capture the NEM-wide value of relieving export curtailment. The values for a particular NEM region reflect the marginal value of reducing operational demand (across the NEM).
5.1	Overall interpretation of CECV	Australian Energy Council	Unlike the RIT-D, there is no apparent carve out for specific customers or customer classes to be exposed to costs or benefits. Export tariffs represent the opportunity to address this and should be linked as a prerequisite to the implementation of any CECV, or as the AEMC hypothesises, to calculate CECVs for DER customers and non-DER customers.	See response to 3.1. Although there is a relationship between CECVs and export tariffs, it is not a direct one. Customer-specific CECVs are not necessary to inform the development of export tariffs.

ID	Theme	Stakeholder	Comment	Response
5.2	Overall interpretation of CECV	AGL	Overall support that the AER should use AEMO or DNSP provided assumptions to develop scenarios where more/less DER exports occur and estimate the costs and benefits under these scenarios, however the AER should also calculate CECVs for DER customers to account for particular impacts to their investment.	The impacts on customer investment in DER are not considered as a separate value stream as it would result in double counting of wholesale market costs/benefits estimated under the CECV methodology. This is because a shortfall in self-generation (and consumption) is met by wholesale electricity market generation.
5.3	Overall interpretation of CECV	Consumer Challenge Panel	Overall support the interpretation of CECV, yet consider that the comparison of more or less DER exports may occur relies on a couple of key pieces of information: 1) what is the base 'hosting capacity' and have the input assumptions to that been tested with consumers as being realistic and proportionate? 2) have the market benefits and costs been considered? 3) have all consumer and demand side options been pursued before the curtailment is valued?	The modelling undertaken for the purpose of estimating CECVs is independent of DNSPs proposal for investment to increase hosting capacity. In line with our DER integration expenditure guidance note, DNSPs should demonstrate how their investment case compares against a base case, which should reflect the existing level of network hosting capacity.
5.4	Overall interpretation of CECV	Endeavour Energy	The CECV in principle should capture the total avoided wholesale marginal costs incurred by the market of an increment reduction in the curtailment off solar PV exports. A focus on estimating dispatch costs (and the avoided marginal generator SRMC value stream) could result wholesale market costs of curtailment being understated, leading to a sub-optimal level of network investment in DER integration.	See response to 2.2.
5.5	Overall interpretation of CECV	SA Power Networks	The AER should clarify the precise role that it envisages the CECV to play in the broader process of determining the prudency and efficiency of network expenditure proposals for DER integration and export service performance incentives.	CECVs will be used to quantify energy related dispatch cost and the FCAS-related resource cost impact by DER export. DNSPs are required to aggregate CECVs according to the export curtailment alleviation profile provided by their proposed investment(s). DNSPs are also permitted to quantify other DER value streams (listed in our DER integration expenditure guidance note) to compute a total benefit figure for input into their cost-benefit analyses. Although our review of incentive arrangements for export services is ongoing, CECVs could be used under an incentive scheme to set rewards where it is demonstrated that DNSPs provide additional value to customers and have not been funded already to do so.
6.1	Link between CECVs and export tariffs	SA Power Networks	The relationship between the CECV's role and export tariffs will be more direct than as described in the Issues Paper. While the introduction of export tariffs may be gradual and subject to transition	In our Draft Export tariff guidelines (Explanatory statement) we note that historical costs associated with providing a network's intrinsic hosting

ID	Theme	Stakeholder	Comment	Response
			management (e.g., by phasing in prices to existing DER customers), ultimately it is customers of export services that will pay for the network costs of enabling this service, and therefore it is important that the value they see in avoiding service curtailment (arising from insufficient network hosting capacity) is considered. The Issues Paper appears to mis-describe the costs to be recovered (subject to customer impact management transition) via export tariffs. We expect these tariffs can recover any costs associated with DER hosting capacity that are incremental to the intrinsic DER network hosting capacity – these may include future network costs but also any sunk costs that may have already been incurred in providing additional DER hosting capacity (i.e., above the intrinsic capacity) and which was incurred specifically for the export service.	capacity should not be recovered through export charges. We also noted that we do not consider it appropriate for a distributor to recover historical network costs through export charges. This is because those costs were primarily or exclusively incurred to provide the network consumption service, with intrinsic hosting capacity for exports being incidental. Moreover, the cost of historical network investment is being recovered through consumption tariffs. We consider historical network costs should continue to be recovered through consumption charges, as should future network costs associated with providing the consumption service.
7.1	Locational estimation of CECVs	Consumer Challenge Panel	There are many variables that influence the ultimate impact of DER on customers across various jurisdictions and by different retailers. Splitting CECVs into regional assessments is well below the level of uncertainty and precision of other calculations impacting customer energy prices.	We agree that many variables influence the impact of DER on customers, however for the purposes of estimating CECVs we have sought to balance modelling accuracy with complexity.
7.2	Locational estimation of CECVs	Endeavour Energy	The AER should estimate CECVs by NEM region although DNSPs should have the flexibility to apply alternative values at a more granular level where accuracy is improved. Estimates should reflect the cost impact to customers in other regions which may result from the interconnected nature of the NEM.	We consider that a consistent approach to estimating CECVs should apply to all DNSPs, and therefore DNSPs should not have the flexibility to apply alternative values.
7.3	Locational estimation of CECVs	Energy Queensland	Agree that CECVs should be estimated by NEM region, but also could be sub-categorised by climate zone.	CECVs are estimated by NEM region to reflect the nature of the wholesale market. Sub-categorising CECVs by climate zone is not necessary for the purpose of investment planning.
8.1	Temporal estimation of CECVs	Australian Energy Council	CECVs need to be captured on a granular level to the extent possible by using short interval CECVs, aligned to 5MS, which are applied to an intra-regional level at a minimum of hourly. This exposes the true costs to augmenting network to accommodate daytime export. Alignment with 5MS also better identifies wholesale market benefits. Networks could aggregate this with reference to their own infrastructure build or pricing proposals, such as pricing a storage investment for one quarter in a year, where they have CECVs aggregated by month (and not by year) for that investment case.	CECVs are estimated on a half-hourly basis rather than at 5-minute granularity. We consider that this approach balances accuracy with additional modelling complexity. In terms of aggregation, DNSPs are required to aggregate CECVs based on an export curtailment alleviation profile. This profile will reflect the result of the proposed network investment.

ID	Theme	Stakeholder	Comment	Response
8.2	Temporal estimation of CECVs	AGL	The level of aggregation of CECVs should reflect individual DNSPs' proposed investment approaches. For example, if a DNSP is proposing to procure services from competitive DER assets in Q1 only, then the CECV should be aggregated to reflect the monthly impact in order to support relevant industry investment and planning. To estimate CECVs into the future, this could be forecast by reference to ASX future market and AEMC price trend reporting. Recommend that the forward period by prescribed by reference to the ASX traded curve which is about three years plus a quarter.	DNSPs are required to aggregate CECVs based on an export curtailment alleviation profile. This profile will reflect the result of the proposed network investment. CECVs are estimated over a 20-year forecast period based on AEMO's Draft 2022 ISP Step change scenario.
8.3	Temporal estimation of CECVs	Ausgrid	The AER should calculate CECVs using a temporal aggregation that reflects changes in dispatch prices throughout the course of the day. This could be done using wholesale market prices from a narrow timespan (5-min intervals) which, for practical purposes, are then aggregated to a broader temporal dimension such as a single year or various pricing windows for tariffs. Recommend that the AER revisit this issue after it has completed its wholesale market modelling and tested the sensitivity of CECVs to different temporal dimensions. The AER should estimate CECVs into the future based on established and agreed AEMO scenarios, and Ausgrid's joint consultancy on CECV methodology, while providing DNSPs with the flexibility to exercise the option to forecast and model changes in CECVs over time.	See responses to 8.1 and 8.2.
8.4	Temporal estimation of CECVs	AusNet Services	The use of annual CECVs is appropriate. Developing CECVs based on, for example, the time of day and/or seasonality is unnecessary at this time. AER guidance on the factors that DNSPs could consider when developing their forecasts of changes in CECVs over time would be welcome. However, DNSPs should have discretion as to how they prepare their own forecasts. This flexibility will ensure DNSPs can consider, in a timely manner, the underlying relationships in the relevant data and the extent to which the underlying drivers of that data may need to change.	We do not consider that annual CECVs are adequate for the purpose of investment planning. Aggregating CECVs to an annual level would require information about the alleviation profiles provided by DNSP investments. Instead, DNSPs are required to aggregate CECVs based on an export curtailment alleviation profile. This will ensure that the overall value provided by the network investment accurately reflects conditions in the wholesale electricity market.
8.5	Temporal estimation of CECVs	Consumer Challenge Panel	There could be value in curtailment during the middle of the day when prices are negative. Curtailment could act as a signal to solar PV owners to invest in storage or demand response if	The CECV methodology recognises this possibility, however it is cost-based rather than price-based. CECVs are estimated on a half-hourly basis and DNSPs are required to

ID	Theme	Stakeholder	Comment	Response
			they can no longer receive feed-in tariff revenue. CECVs need to reflect this, so at a minimum should be different for peak and off-peak periods.	aggregate CECVs based on an export curtailment alleviation profile.
8.6	Temporal estimation of CECVs	Endeavour Energy	Temporal aggregation should reflect seasonal average 24-hour profiles at 5-minute granularity, potentially distinguishing between weekend and weekdays. Suggest an approach to aggregation which reflects seasonal average 24-hour profiles at 5-minute granularity with the possibility of distinguishing between weekend and weekdays to capture the material changes in the demand and SRMC curves. In this scenario, there would be eight daily CECV curves with 5-minute granularity.	See response to 8.1.
8.7	Temporal estimation of CECVs	Endeavour Energy	An annual forecast period is appropriate for the CECVs. Whilst it would be appropriate for the risk of inaccurately forecasting CECVs into the future and the costs of this risk lie with the same party, DNSPs may not have the relevant expertise or oversight of the generation sector to accurately forecast changes in CECVs. The AER would be better placed to do this. Alternatively, the AER could develop a formulaic approach to forecasting CECVs into the future and identify the data inputs and/or assumptions DNSPs should use.	CECVs are estimated over a 20-year forecast period based on AEMO's Draft 2022 ISP Step change scenario. This provides a consistent estimation approach across DNSPs and does not require DNSPs to identify their own assumptions.
8.8	Temporal estimation of CECVs	Energy Queensland	Support the AER developing values over different time periods where the incremental cost and effort of doing so is sufficiently low. Changes to CECVs (in the future) could be included as part of the sensitivity analysis in cost-benefit calculations, whether estimated by DNSPs or the AER.	See responses to 8.1 and 8.2.
8.9	Temporal estimation of CECVs	Jemena	At a minimum CECVs should be broken down into three periods throughout the day, including during the middle of the day, the network peak period and other times. This is broadly consistent with the Victorian ESC's approach for establishing minimum feed-in tariffs in Victoria.	See response to 8.1.
8.10	Temporal estimation of CECVs	Jemena	The AER should forecast CECVs into the future to assist DNSPs prepare investment proposals. This would ensure that DNSPs use a consistent approach, which was sought by many stakeholders including consumer groups during the 2021-26 price resets for the Victorian DNSPs. Alternatively, the AER should provide guidance to DNSPs on acceptable approaches for	See response to 8.7.

ID	Theme	Stakeholder	Comment	Response
			forecasting changes in CECVs over time.	
8.11	Temporal estimation of CECVs	Public Interest Advocacy Centre	A consistent approach across all DNSPs should be used to forecast CECVs. DNSPs may be best placed to forecast CECVs, however, their methodology for doing so should consistent and transparent.	See response to 8.7.
8.12	Temporal estimation of CECVs	Red Energy	Distributors must ensure they do not attempt to capture any economic losses to justify a proposed augmentation from DER exports during negative price periods. However, in practice, DER exports which are made during negative price periods and paid feed in tariffs do not create any economic value. On this basis, they should not form part of the economic loss calculation to customers and the broader market. We recommend that CECVs are captured on a granular level, therefore we support the development of hourly CECVs applied on an intra-regional level.	See response to 8.5.
8.13	Temporal estimation of CECVs	South Australia Energy and Technical Regulation Division	CECVs should be estimated annually by NEM region and reflect the costs to customers in other NEM regions, provided that interconnector behaviour can be accurately modelled. CECVs should reflect seasonality and the time of day.	See responses to 8.1 and 8.2.
8.14	Temporal estimation of CECVs	South Australia Energy and Technical Regulation Division	Unless they could be demonstrated to be robust, CECV forecasts beyond one year should be left to the discretion of DNSPs.	See response to 8.7.
8.15	Temporal estimation of CECVs	SA Power Networks	The AER should also clarify: 1) The type of annual CECV update intended - if this is an inflation update, or something more extensive which poses challenges to the long process of preparing a regulatory proposal, and 2) the timing of the 5-yearly CECV methodology reviews, which should occur on the same timeframes as the VCR given their similar regulatory purpose.	As noted in section 3, for annual updates we will consider whether input assumptions under the ISP's Step change scenario have materially changed to reflect new information or forecasts. If there are no material changes, we will only update CECV estimates to account for changes in inflation. This will ensure that in economic terms, real values of CECV are maintained between CECV reviews. If there are material changes, we will also re-estimate CECVs using the new assumptions and also update these values in the DNSP model. We will also consider whether the characteristic day types (discussed in section 4) require updating in the DNSP model. NER rule 8.13(f) states: The AER must, at least once every five years, review the CECV methodology and following such review, publish

ID	Theme	Stakeholder	Comment	Response
				either: (1) an updated CECV methodology; or (2) a notice stating that the existing CECV methodology was not varied as a result of the review. The next VCR review is due by 31 December 2024. We have not predicted a date earlier than the 5-yearly requirement for reviewing the CECV methodology (by 30 June 2027), however we will consider the benefits of reviewing both the VCR and CECV methodology together.
9.1	Modelling issues – shorthand v longhand	AGL	In the short to medium term the shorthand approach would probably be adequate to estimate the CECV. In the longer term, a market modelling methodology may be required as batteries and other storage becomes more prevalent. This is especially true as when curtailment increases, the marginal benefit calculation may no longer be appropriate.	The CECV methodology adopts a longhand approach to modelling, however it is a relatively simple approach, with a view to making improvements and adaptations over time. We consider this is preferable to initially developing a shorthand approach as this would likely result in more significant changes to the methodology in the future rather than incremental improvements.
9.2	Modelling issues – shorthand v longhand	AusNet Services	While longhand approaches to calculating CECVs may have some benefits, shorthand approaches provide sufficient forecasting ability. Given the AER will be calculating CECVs annually (for the year ahead), any error and/or change in demand/changes in technology cost can be addressed as part of the next (yearly) calculation. Importantly, shorthand approaches avoid some of the major drawbacks associated with using electricity market modelling, namely the need for agreement on numerous inputs and the lack of transparency (the latter of which is increasingly important for stakeholders).	The methodology uses electricity market modelling to improve the robustness of CECV estimates. As noted in section 3, if there are material changes to AEMO's ISP Step change scenario assumptions, we will re-estimate CECVs using the new assumptions and also update these values in the DNSP model. We will also consider whether the characteristic day types require updating in the DNSP model.
9.3	Modelling issues – shorthand v longhand	Endeavour Energy	It is generally accepted that market modelling provides more accurate estimates of wholesale market benefits as it is better able to capture generator behaviours and interrelationships within the electricity sector that will have a bearing on dispatch costs. Notably, this approach requires a long-term view of how the NEM will be configured (to capture the avoided generation capacity investment value stream) for which the AER would be well placed to forecast. It would therefore be appropriate for the AER to apply a longhand approach. However, DNSPs should have the flexibility to apply the simpler shorthand approach.	DNSPs will not have the flexibility to apply their own approach to the estimation of CECVs. However, DNSPs are able to use the DNSP model to customise the aggregation of CECVs based on their expected alleviation profiles. Further, DNSPs will be permitted to identify and quantify other DER value streams listed in the DER integration expenditure guidance note.
9.4	Modelling issues – shorthand v longhand	Jemena	The AER should test both shorthand and longhand methods when calculating CECVs, including	Given the general support for using a longhand modelling approach, we do not intend to test shorthand approaches.

ID	Theme	Stakeholder	Comment	Response
			conducting scenario modelling and sensitivity analysis on both approaches.	
10.1	Modelling issues – other	Ausgrid	Generator bidding behaviour should be incorporated into electricity market modelling, as it will support the development of CECVs that closely reflect potential or likely market conditions. If algorithms are applied to reflect generator bidding behaviour, the algorithms, assumption and impacts of these should be transparently reported to support constructive engagement by DNSPs.	The draft methodology does not incorporate generator bidding behaviour. As the modelling is cost-based, we assume that generator bids reflect their short-run marginal cost.
10.2	Modelling issues – other	Consumer Challenge Panel	Do not believe generator bidding should be modelled. It is too variable, too dynamic, also subject to many other external factors. Certainly, though, the costs of generator operation and higher night-time prices must be considered.	See response to 10.1.
10.3	Modelling issues – other	Endeavour Energy	A hybrid model of bidding behaviour could be used if bidding behaviour can be attributed to physical characteristics rather than specific strategies used by generators which may change over time. For example, while coal generators will be classified as having an average SRMC above zero, in practice there is a large amount of coal capacity which bids at the market floor. This can be linked directly to the fact that due to minimum load of coal plants, the SRMC of a certain portion of the coal plant is market floor (or lower in reality) while the residual SRMC of the coal plant is a measure of fuel and operating cost. Hence, a model of bidding behaviour based on SRMC could be adjusted to account for these market characteristics which are likely to persist in the long term.	See response to 10.1.
10.4	Modelling issues – other	Public Interest Advocacy Centre	Any assumptions around strategic bidders should have defined selection or analysis criteria. If the AER does model bidding behaviour using a choice of strategic bidders, it should undertake additional consultation and analysis regarding input assumptions prior to commencement of any modelling. The choice of strategic participants and the level of strategic choice allowed must be subject to rigorous and transparent consultation.	See response to 10.1.
10.5	Modelling issues – other	AGL	Due to the regionalisation of the CECV but using a dispatch cost approach rather than spot price, the apportionment of value to each region is somewhat ambiguous (especially once loop flows begin with EnergyConnect). Some simple options might be to apportion using the previous year IR-TUOS values or using historical flow during curtailment	The process of estimating CECVs is based on a simulation of marginal dispatch costs and incorporates future interconnector upgrades as per the ISP optimal development path.

ID	Theme	Stakeholder	Comment	Response
			periods. Arguably, it would be appropriate to proportion the benefit with interconnector adjusted losses when there is no separation between regions.	
10.6	Modelling issues – other	Endeavour Energy	Interconnector impacts could be included through using the wholesale price in interconnected states weighted by the impact of PV generation on regional electricity imports/exports. This could then be added to a more complex shorthand calculation method for the state in which the CECV is being calculated.	See response to 10.5.
10.7	Modelling issues – other	Public Interest Advocacy Centre	Interconnector behaviour should not be considered because it is too hard to draw a meaningful link.	See response to 10.5.
11.1	Other – intangible costs and benefits	CitiPower, Powercor & United Energy	While the intangible costs to consumers of export curtailment are more difficult to measure, that does not mean they, and therefore customer expectations held when investing in DER, should be discounted altogether. Customers purchase solar panels and batteries for many reasons, including customer empowerment and environmental factors, as well as financial value. Not factoring intangible benefits into the calculation will result in undervaluation of customer value leading to inefficient investment outcomes, particularly as the CECV will drive the strength of any export service incentive scheme, the benefits case of proposed network investments to enable export services and the value of export tariffs (which should be established by capping the LRMC at the CECV to ensure export charges are no more than the customer value of export, given at that point, customers would prefer exports to be curtailed). The omission of intangible costs is also inconsistent with the AER's approach to the VCR. The VCR methodology includes both indirect costs (loss of business revenue and productivity) and intangible costs (reduction in convenience, comfort, safety and amenity). The VCR methodology includes significant customer engagement which is a critical foundation of understanding customer value.	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. We do not consider that DER owners' willingness to pay a premium for DER represents an electricity consumer surplus, or that intangible benefits represent a producer surplus (where DER owners make a loss on their investment). Further, the VaDER methodology study revealed that most customers invest in DER for financial benefits, and the value of intangible benefits not captured in existing DER value streams is small. We note that the omission of intangible costs is inconsistent with our approach to estimating VCRs. VCRs relate to network reliability. Since there are no cost-effective substitutes for reliability (for most customers), willingness-to-pay surveys provide a reasonable method for estimating the value that customers place on reliability. In contrast, DER competes with centralised electricity generation and can substitute it directly. Modelling the impact of this substitution directly (as is done in the CECV methodology) provides a more accurate estimate and removes the need to undertake an alternative estimation technique such as a willingness-to-pay survey.

ID	Theme	Stakeholder	Comment	Response
12.1	Other – application of methodology	Power & Water Corporation (NT)	Appropriate consideration must be given to whether the methodology and values can apply to unique operating circumstances in the Northern Territory (NT), or whether alternative approaches need to be developed (noting that the NT does not have an interconnected electricity market, and instead operates three standalone networks).	See section 3.2.2. Although Power and Water Corporation (NT) will not have access to CECVs as inputs to potential business cases via this methodology, we expect that its estimation of benefits associated with avoided dispatch costs should reflect the CECV methodology and adopt appropriate cost effective alternative numerical assessments of dispatch costs that considers both the temporal nature of costs and the alleviation profile associated with any proposed DER integration investments.

Glossary

Term	Definition
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
BTM	Behind-the-meter
CECV	Customer Export Curtailment Value
CSIRO	Commonwealth Scientific and Industrial Research Organisation
DER	Distributed Energy Resources
DNSP	Distribution Network Service Provider
EFOR	Expected forced outage rates
ESS	Essential System Services
FCAS	Frequency Control Ancillary Services
ISP	Integrated System Plan
LRMC	Long run marginal cost
NEM	National Electricity Market
NEO	National Electricity Objective
NER	National Electricity Rules
POE	Probability of exceedance
RIT-D	Regulatory Investment Test - Distribution
SCS	Standard control service
SRMC	Short run marginal cost
VaDER	Value of Distributed Energy Resources