Final CECV methodology

Explanatory statement

June 2022

AUSTRALIAN ENERGY REGULATOR

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1 Introduction

This explanatory statement provides our rationale for the Final 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.

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;
- 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.

[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.

Oakley Greenwood provided a summary of its recommended approach to quantifying wholesale market value streams at our stakeholder workshop in February 2022 and formalised its advice in April 2022.[5]

We published the Draft CECV methodology and accompanying explanatory statement (the draft report referred to under the Rules consultation procedures) on 8 April 2022 and sought stakeholder submissions by 6 May.[6] We received 14 submissions, which are published on the AER website.[7] We have considered these submissions in developing the final CECV methodology.[8]

Oakley Greenwood updated its report in June 2022, addressing submissions on the draft CECV methodology and finalising the proposed DNSP model.[9]

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.[10] We formalised the recommendations of the VaDER methodology study through the publication of our draft DER integration expenditure guidance note in July 2021, and finalised this guidance note in June 2022.[11] 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.[12]

The final CECV methodology supplements our final DER integration expenditure guidance note, which 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 CECV methodology provides our approach to valuing a subset of these DER value streams (specifically some of those related to the wholesale electricity 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

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

[6] NER rule 8.9(h).

[7] 'Customer export curtailment value methodology – Submissions'

[8] Appendix A provides our responses to stakeholder submissions.

[9] Oakley Greenwood, 'CECV Methodology – Final Report', June 2022.

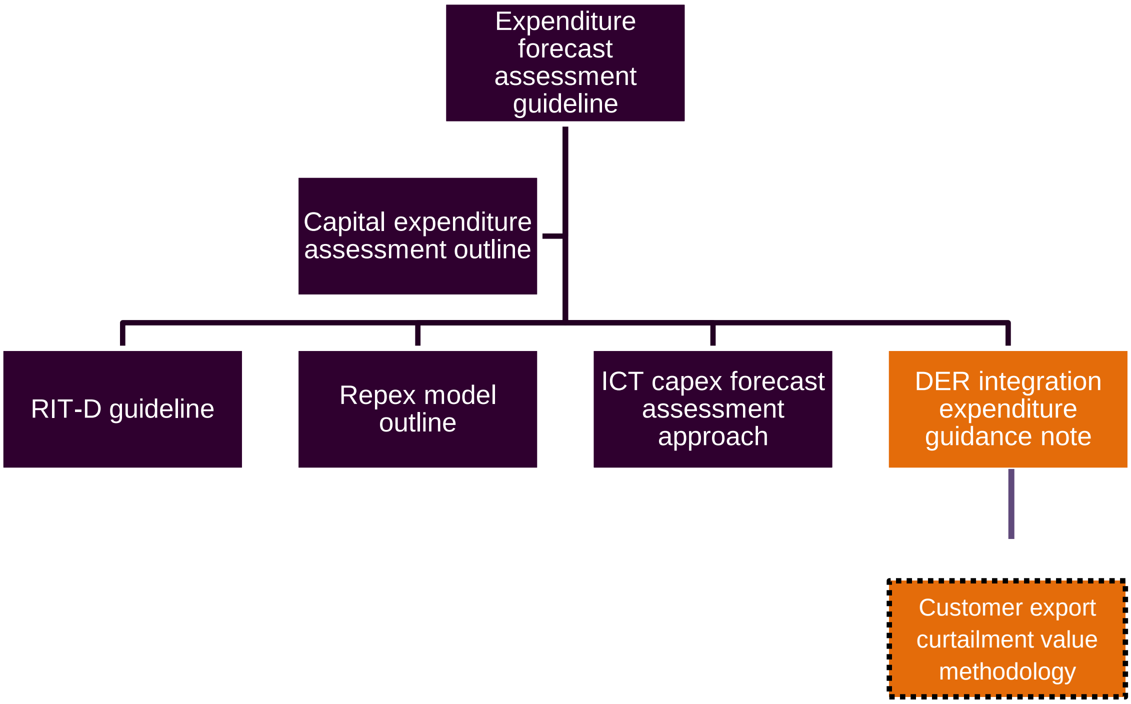
[10] Koerner M, Graham P, Spak, B, Walton F, Kerin R (2020), 'Value of Distributed Energy Resources, Methodology Study: Final Report', CutlerMerz, CSIRO, Australia.

[11] AER, 'Distributed Energy Resources Integration Expenditure Guidance Note', June 2022.

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

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[13] 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 DER integration expenditure guidance note will help DNSPs step through the process of developing DER integration plans and investment proposals with their customers, incorporates relevant CECV values and is summarised in Figure 1.2.

[13] AER, 'DER integration expenditure guidance note', June 2022.

Figure 1.2: Process for developing DER integration investment proposals

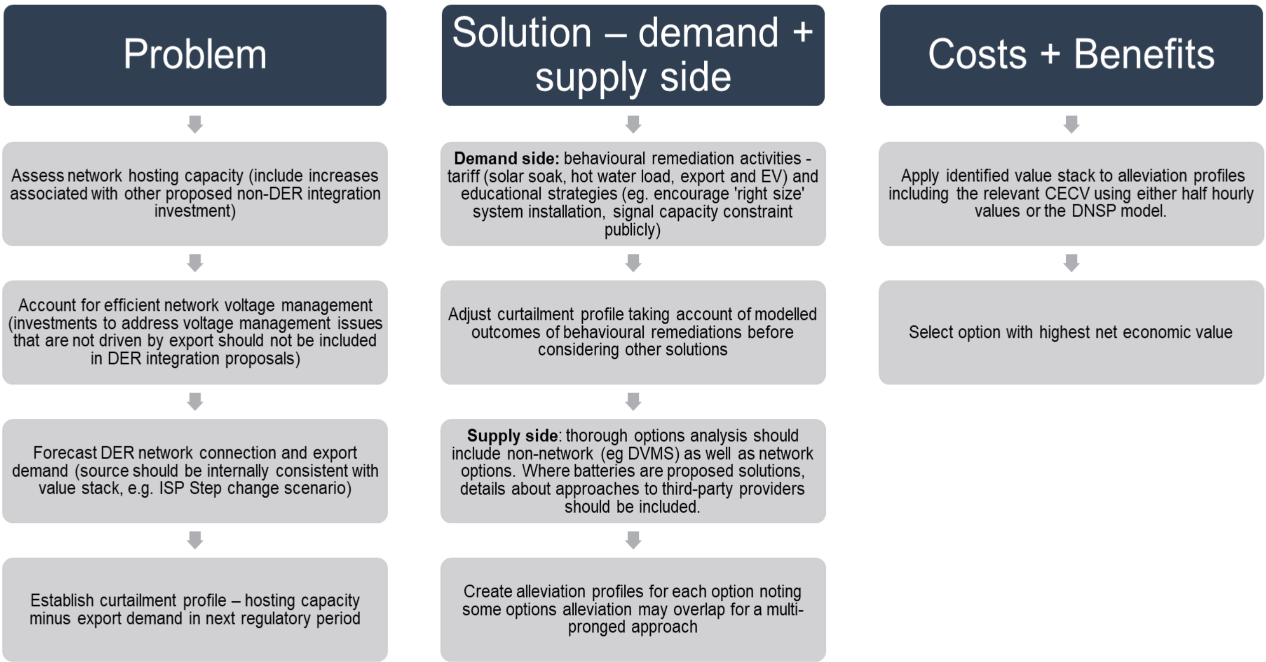
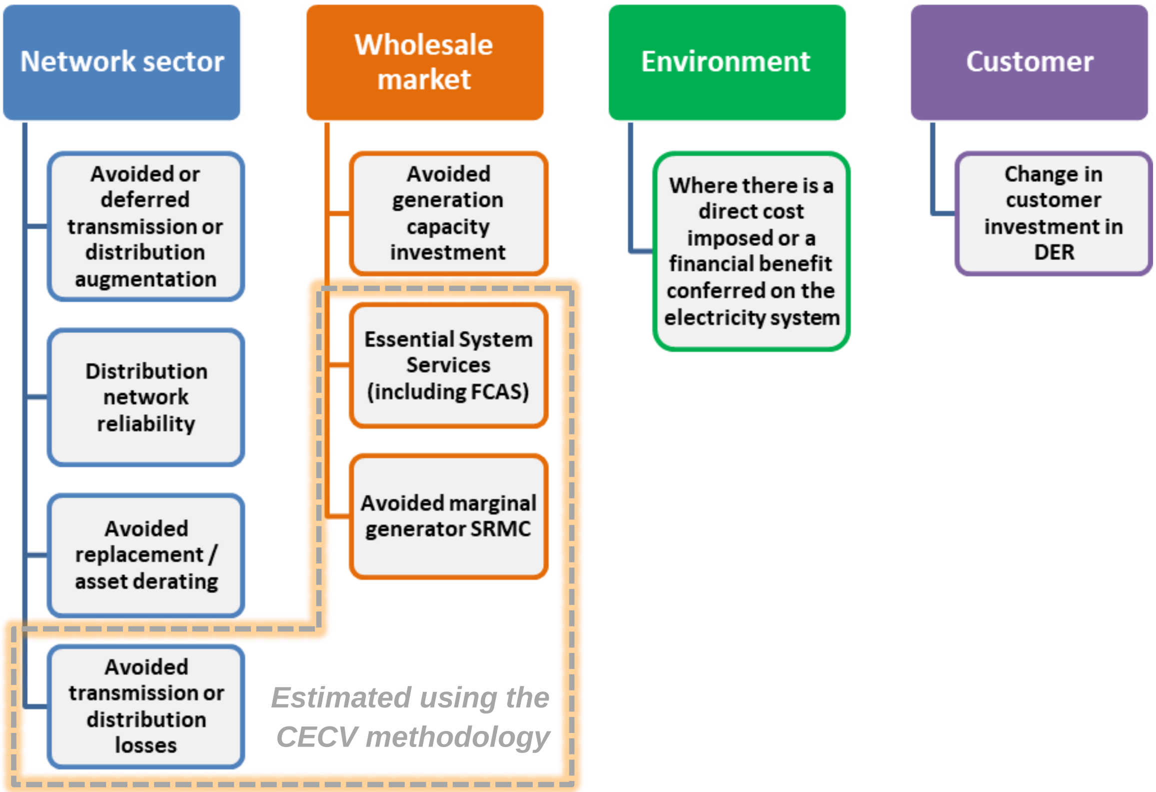


Figure 1.3 illustrates the DER value streams considered as part of the DER integration expenditure guidance note, and the value streams that are captured in the CECV methodology.

Figure 1.3: DER value streams provided by AER guidance



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. These guidelines were developed under a separate consultation process.[14]

[14] AER, 'Export Tariff Guidelines', May 2022.

1.3 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 under the CECV methodology are published separately on our website.[15]

[15] Oakley Greenwood, 'CECV Methodology – Final Report', June 2022.

2 Interpretation of CECV

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

In the draft methodology our position was that CECVs capture two of the wholesale market value streams: 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 considered 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.

Notably, this approach does not quantify the impact of incremental DER export on possible changes to generation or transmission system investment costs. This was based on Oakley Greenwood's advice that it expected this 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.[16]

We also noted that DNSPs would not be precluded from quantifying other value streams listed in Table 2.1 themselves (under the guidance note), including avoided generation capacity investment costs.

2.1.1 Stakeholder responses

Stakeholder responses on the issue of DER value streams broadly focused on the exclusion of avoided generation capacity investment costs and other value streams based on customer willingness to pay.

Avoided generation capacity investment costs

Energy Networks Australia (ENA) engaged HoustonKemp to provide an independent assessment of our methodology.[17] The ENA's submission, including HoustonKemp's assessment, was supported by most of the DNSPs.[18] HoustonKemp's assessment concluded that:

- the methodology produces a granular and sophisticated estimation of only a portion of the benefits and excludes a material component, i.e., the benefits arising from avoiding generation capacity investments – thereby risking materially underestimating the CECV,
- the CECVs estimated are not consistent with the levels of investment in solar PV expected under AEMO's Integrated System Plan modelling; and

[16] Oakley Greenwood, 'CECV Methodology – Interim Report', April 2022.

[17] Energy Networks Australia, 'Submission to the draft customer export curtailment value methodology', May 2022.

[18] Including Ausgrid, AusNet Services, CitiPower, Powercor & United Energy, Endeavour Energy, Essential Energy, Evoenergy, Jemena and SA Power Networks.

- the modelling of CECVs makes assumptions that lead to a downward bias in the estimates.[19]

Comments on the draft other value streams

CitiPower, Powercor and United Energy submitted that including additional value streams, so long as they are quantifiable, evidence-based and valued by customers, would more accurately reflect the value that customers place on export services and is likely to result in a more efficient level of export service delivery. It suggested that, if customer values are not included in the CECV, we should allow networks to include customer preferences within the benefits case under our DER integration expenditure guideline if these can be demonstrated to reflect the views of the DNSPs' customer base through customer research.[20]

Similarly, SA Power Networks submitted that distributors should be able to undertake engagement and research on the extent to which customers, particularly those with DER, are willing to pay for higher levels of network hosting capacity (above values under the CECV or other value streams).[21]

2.1.2 Final decision

We maintain our draft decision position on DER value streams, with CECVs capturing 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. In arriving at this decision we considered stakeholders submissions, additional advice from Oakley Greenwood, as well as the relationship between the CECV methodology and our broader guidance on DER integration expenditure.

Avoided generation capacity investment costs

Oakley Greenwood's final report provides a complete response to HoustonKemp's assessment of the Draft CECV methodology.[22] In that response, Oakley Greenwood's notes:

> It is absolutely the case that the alleviation of DER export curtailment could, under certain circumstances, impact wholesale generation investment requirements and costs and potentially, even transmission investment costs. However, the quantum of incremental export needed to affect investment requirements at the interconnected NEM level will probably always exceed what an individual DNSP is likely to propose in the way of alleviation and will therefore require an estimation of the likely aggregate effect of DER curtailment alleviation at the regional or NEM level.

[19] We note that not all of the issues raised by HoustonKemp explicitly relate to the issue of DER value streams, however for simplicity and ease of reference, we also discuss these issues in this section.

[20] CitiPower, Powercor & United Energy, '[Submission to the draft customer export curtailment value methodology](#)', May 2022.

[21] SA Power Networks, '[Submission to the draft customer export curtailment value methodology](#)', May 2022.

[22] Oakley Greenwood, '[CECV Methodology – Final Report](#)', June 2022.

> Any attempt to assess and integrate the impacts of DER export curtailment alleviation on upstream investment costs will require a with/without approach of the sort that Houston/Kemp has used. The shortcoming in HoustonKemp modelling… was the use of a demonstrably unrealistic alleviation profile.[23]

More specifically, Oakley Greenwood noted that the alleviation profile is arguably the most important input in estimating the CECV. HoustonKemp has not provided any detail on the quantum of their alleviation profile, or any empirical evidence to support the critical assumption that regional DER exports are curtailed for the same amount every day from 11am to 2pm regardless of weather or demand conditions.

It noted that while it does not have direct evidence, it is reasonable to argue that the "everyday" alleviation profile is unrealistic because:

- the curtailment of rooftop PV exports will not occur on rainy or cloudy days
- even during sunny conditions, curtailment of rooftop PV would require that household demand and solar irradiation are present in a specific range of proportions to one another (e.g. very low demand and high irradiation, or low to medium demand and very high irradiation), and noting that
- the application of dynamic operating envelopes as opposed to static limits will further reduce the likelihood of "everyday" curtailment.

Oakely Greenwood has also included a thorough response to additional, more technical modelling concerns raised by HoustonKemp that also includes further analysis to demonstrate the likely overestimation of CECV's by HoustonKemp's approach.[24]

The AER agrees with Oakely Greenwood's analysis. From the information we have available, even within networks of significant PV penetration, network curtailment is limited. A recent Australian PV Institute study, *Curtailment and Network Voltage Analysis Study Project Report*, found that tripping … and curtailment was not significant for most energy users. On average, the (PV) systems experienced around 13 kWh of curtailed generation per year (less than 1% of their total generation).[25] It is likely that several years of sustained PV growth in low penetration networks could slowly increase export curtailment and accompanying potential for alleviation of that curtailment. As potential alleviation across networks grows, it could lead to market benefits associated with avoiding grid-scale investment over time. We consider that this is a key consideration in determining the appropriate timing of a review of the CECV methodology and highlight this as such in section 3.5.2 below.

[23] Oakley Greenwood, 'CECV Methodology – Final Report', June 2022.

[24] Oakley Greenwood, 'CECV Methodology – Final Report', June 2022.

[25] Collaboration on Energy and Environmental Markets at UNSW, 'Curtailment and Network Voltage Analysis Study Project Report', August 2021

See also: University of New South Wales (2020), 'Voltage Analysis of the LV Distribution Network in the Australian National Electricity Market', May 2020.

Other value streams

Our final DER integration expenditure guidance note provides our position on the potential for DNSPs to quantify other DER value streams based on customer willingness to pay. In summary, if proposing additional value streams:

- DNSPs should consider whether the benefits are already reflected in existing value streams, such as those related to wholesale market or network sector benefits. If they are, DNSPs should use the methods stipulated in the guidance note to quantify these benefits.
- DNSPs should demonstrate that values will accrue to a producer, consumer or transporter of electricity in the NEM.
- DNSPs should demonstrate that existing DER value streams (which capture financial costs and benefits and are likely to be more material) have already been quantified, or considered in the cost-benefit analysis.

2.2 Curtailment

Customer export curtailment means reducing tripping or otherwise limiting customer export.[26] In the draft methodology we required 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.

2.2.1 Stakeholder responses

Stakeholders were generally supportive of DNSPs developing alleviation profiles to appropriately aggregate CECVs, however some DNSPs raised concerns about their ability to accurately estimate alleviation profiles.

Ausgrid submitted that the development of alleviation profiles is prefaced on an assumed level of visibility of low voltage networks and hosting capacity. It noted that while it

[26] NER rule 8.13(a).

undertakes detailed modelling of low voltage networks, there are limitations inherent in any modelling exercise and consequently the alleviation generated by any given investment may depart from modelled alleviation.[27] AusNet Services noted that while the alleviation profile concept is sound in principle, developing a profile for each proposed investment will be a complex exercise and each DNSP is likely to approach this issue slightly differently. It suggested that DNSPs will need additional resources (and time) to develop, embed and refine this process.[28]

2.2.2 Final decision

We maintain our draft decision position on customer export curtailment. Although we do not account for curtailment when we estimate CECVs, DNSPs are required to demonstrate how proposed investments will alleviate export curtailment and aggregate CECVs accordingly.

We recognise that there may be challenges associated with estimating alleviation profiles and DNSPs may require time to undertake detailed modelling to develop this understanding. However, if DNSPs are unable to credibly estimate the timing and volume of additional DER exports enabled by their proposed investments, their customers will not realise the benefits of efficient DER integration. Given the likelihood that wholesale market benefits (derived with CECVs) will represent a significant portion of the claimed benefits in a cost-benefit analysis, it is reasonable for customers to expect that DNSPs have thoroughly considered the quantity and time distribution of DER exports it expects its proposed investment will provide.

While the AER supports the idea of the DNSP model being used to allow certain types of sensitivity testing as suggested by the CCP, variations in fuel prices is not a variable that could be tested in this way. This is because, fuel prices would, in the first instance, affect the marginal cost of generation and therefore would affect the CECVs that are contained in the DNSP model, which would have been derived from the PLEXOS modelling. Alternatively, higher prices could have an indirect effect on PV uptake, which may in tun affect the DNSP’s alleviation profile. To the CCP’s point, the DNSP could compare this as an alternative alleviation profile.

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 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.

2.3 Distribution of costs and benefits

In the draft methodology we noted that CECVs will 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 did not propose to estimate different CECVs for DER customers and non-DER customers, and noted that all DER value streams, including wholesale market value

[27] Ausgrid, ‘Submission to the draft customer export curtailment value methodology’, May 2022.

[28] AusNet Services, ‘Submission to the draft customer export curtailment value methodology’, May 2022.

streams, are likely to vary according to several factors, including customer type, time and location, depending on the proposed DER integration investment.

2.3.1 Stakeholder responses

Stakeholders agreed with our position. AusNet Services noted that DNSPs must ensure that export tariffs reflect the efficient cost of providing the service to which that tariff relates. To the extent that CECVs are an input into estimating the cost of providing additional capacity for export then there is a link, but it is indirect.[29]

2.3.2 Final decision

We maintain our draft decision position that, CECVs capture the costs and benefits to all customers, and are not specific to DER or non-DER customers. Although there is a relationship between CECVs and export tariffs, any export charges that are set should reflect the efficient long run marginal cost of supplying the export service.[30]

[29] AusNet Services, 'Submission to the draft customer export curtailment value methodology', May 2022.

[30] AER, 'Export Tariff Guidelines', May 2022.

3 Estimation of CECV

In this section we discuss the level of temporal and locational granularity at which we estimate CECVs, as well as the modelling process for estimating CECVs.

3.1 Temporal nature of costs

In the draft methodology we noted that the value of reducing DER export curtailment will depend on the condition of the wholesale market at the time of the reduced curtailment. 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.

Under the draft methodology we estimated CECVs on a half-hourly basis over a 20-year forecast period. We considered that this represented a sufficient degree of disaggregation and adequately captures the differences in marginal export values over the course of each day.

3.1.1 Stakeholder responses

Stakeholders generally agreed that a high level of disaggregation was required to capture temporal differences in values and were satisfied that half-hourly values were appropriate.

Energy Queensland submitted that less granularity would not materially impact the accuracy of the benefit calculation, and suggested that a single average value should be provided for CECV for each year of the forecast, similar to what is used for Value of Customer Reliability. It added that providing further granularity does not significantly increase the accuracy but adds significantly to the complexity.[31] Red Energy and Lumo Energy suggested that CECVs would need to be captured at five-minute intervals consistent with the NEM dispatch process to capture the value of curtailment values more accurately.[32]

3.1.2 Final decision

We maintain our draft decision position that CECVs should be estimated 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.

We disagree with Energy Queensland's assertion that a single average value for each year is suitable. Oakley Greenwood has demonstrated that there are material differences in average values based on a comparison of time-weighted, rooftop PV generation-weighted and "proxy alleviation profile" values in each region. Therefore it is important that we estimate values at

[31] Energy Queensland, 'Submission to the draft customer export curtailment value methodology', May 2022.

[32] Red Energy & Lumo Energy, 'Submission to the draft customer export curtailment value methodology', May 2022.

a disaggregated level, and allow DNSPs to aggregate or average CECVs depending on the alleviation profile provided by proposed investments.

While we agree that estimating CECVs at five-minute intervals is consistent with the NEM dispatch process, this approach would require us to make assumptions about AEMO's demand forecast and variable renewable energy traces, which are not available at this level of granularity. In any case, 5-minute CECVs would only be beneficial if DNSPs were developing alleviation profiles were also at the 5-minute level, or the 5-minute values could be expected to produce materially different CECVs for the characteristic days (discussed in section 4).[33] We do not consider this to be likely, and so are satisfied that half-hourly values are sufficient.

3.2 Locational nature of costs

The NEM is a wholesale commodity exchange for electricity across the five interconnected states.[34] 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.[35]

In the draft methodology we estimated CECVs by NEM region as this reflects the structure of the wholesale electricity market, and noted that DNSPs are expected to apply the CECVs for their own region.

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.

Simply Energy suggested that distribution businesses should retain the ability to obtain location specific CECV's where there are significant variations that contrast with remaining network characteristics (for example, significantly higher or lower rooftop solar PV installations).[36] Red Energy and Lumo Energy suggested that CECVs should be developed on an intra-regional level reflecting demand at the regional level. By doing this, the CECV methodology would more accurately reflect demand at the regional level improving the accuracy of the CECV's methodology's outputs in order to justify any augmentation.[37]

[33] Oakley Greenwood, 'CECV Methodology – Final Repor't, June 2022.

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

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

[36] Simply Energy, 'Submission to the draft customer export curtailment value methodology', May 2022.

[37] Red Energy & Lumo Energy, 'Submission to the draft customer export curtailment value methodology', May 2022.

3.2.2 Final decision

We maintain our draft decision position on the locational nature of costs, with CECVs estimated by NEM region. It is not clear how DNSPs would estimate CECVs at a more granular level, given that CECVs are estimated using electricity market modelling of the NEM dispatch. In any case, we consider that CECVs applied by DNSPs should be estimated in a consistent manner under our methodology. We recognise that the occurrence of DER curtailment on distribution networks will vary by location, and so DNSPs will apply CECVs based on their planned alleviation of this curtailment. We discuss this further in section 4 in the context of the DNSP model.

Finally, we reiterate that since the focus of the methodology is on the operation of the NEM, at this stage it 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 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.

3.3 Modelling issues

In the draft methodology we used electricity market modelling (PLEXOS) to estimate CECVs. We considered that this approach would result in more accurate CECV estimates when compared with shorthand approaches.

We also detailed the modelling process for estimating CECVs, including how CECVs capture:

- avoided dispatch costs, based on a simulation of the NEM dispatch procedure;
- the impact of FCAS services, based on an approximation of the eight existing services; and
- transmission and distribution losses.

We sought views from stakeholders on the model inputs and assumptions and the process of estimating CECVs.

3.3.1 Stakeholder responses

Stakeholders generally supported us using electricity market modelling to estimate CECVs as this will provide the most accurate estimates. Endeavour Energy submitted that market modelling has limitations that should be considered before discounting the use of shorthand methods. It suggested that when using market modelling it can be hard to distinguish the extent to which the estimates are driven by the market model design versus the input assumptions.

Some stakeholders provided specific comments about the model inputs and assumptions.

AusNet Services considered that each DNSP should be able to propose alternative inputs should it deem them appropriate. It also suggested that the sensitivity of each input should be considered as this will provide a range of reasonable inputs to be assessed when undertaking this type of modelling. Endeavour Energy also noted that there may need to be consideration of sensitivities and ranged approaches to inputs in order to provide a confidence band of CECV estimates rather than relying on a single set of values over a long period. It also submitted that the various ISP scenarios have different views on demand from sources such as aggregated and disaggregated DER. This means that the draft methodology is potentially discounting high demand scenarios such as the high electrification “hydrogen superpower” ISP scenario, which could risk network underinvestment. Finally, Endeavour Energy noted that it is plausible that future ISPs will introduce other scenarios which may be more likely to occur or even potentially rename the Step Change scenario. It suggested that we consider either providing estimates for other ISP scenarios or a weighted approach to account for the uncertainty which spans across all ISP scenario outcomes.

The Consumer Challenge Panel commented on the selection of POE50 demand traces. It noted that it would be interesting to see if the benefits of reduced export curtailment would have a larger impact under POE10 peak demand when the network is under more operational pressure.

3.3.2 Final decision

The final methodology applies electricity market modelling to estimate CECVs (using PLEXOS). We consider that this will result in more accurate CECV estimates than those estimated using shorthand approaches. We also consider that by modelling AEMO’s ISP Step Change scenario, the model inputs and assumptions are transparent.

In response to specific comments about model inputs and assumptions:

- AusNet Services’ suggestion that DNSPs propose their own model inputs implies that they will estimate CECVs themselves. We don’t consider that there is value in DNSPs estimating their own values as we expect that they will apply our published CECVs.
- We consider that Endeavour Energy’s suggestion to model different scenarios appears reasonable, however gives rise to a range of practical challenges in both estimating and applying values. For example, a wide range of CECV estimates does not provide customers with certainty and DNSPs would likely select values at the top of the range in order to justify higher cost investments. In these instances, we would question whether the selected values reflect a reasonable assumption about the future of the energy market. Adopting AEMO’s Step Change scenario (or another future scenario considered to be the most likely) in estimating CECVs provides greater certainty and prevents DNSPs from making their own predictions, which may be different. We agree that this is plausible for future ISPs to introduce a new most likely scenario, or rename the Step Change scenario. Therefore, in the final CECV methodology we note that the modelling of CECVs is based on the most likely scenario under AEMO’s ISP, which for the initial estimation of CECVs is AEMO’s Draft ISP 2022 Step Change scenario.
- Oakley Greenwood commented on the demand assumption in its interim report. It noted that POE10 demand would be important for reliability modelling or studies where scarcity pricing due to strategic bidding is the key focus. Given the fact that 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.[38]

In the following sections we detail the operation of the model under the final CECV methodology.

Model summary

The final 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.[39] 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.
- For FCAS services, the modelling process described above approximates the impact of the eight FCAS services[40] 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).[41]
- 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.

[38] Oakley Greenwood, 'CECV Methodology – Interim Report', April 2022.

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

[40] 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.

[41] 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).

Model inputs

Model inputs and sources (for the initial estimation of CECVs) 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.[42]

Table 3.1: Model inputs

Input	Source
Existing and committed unit capacity	Draft ISP 2022 assumptions (2021 IASR)[43]
Existing and new generator operating characteristics	Draft ISP 2022 Step Change (2021 IASR)[44]
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).[45] Consistent with modelling practices, the algorithm is appropriately adapted to ensure storage and other energy constraints (such as hydro) are dispatched to minimise total system cost (including FCAS) for each modelled year.

A single simulation is undertaken using POE50 demand traces.[46] 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.[47]

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

[42] Oakley Greenwood, 'CECV Methodology – Interim Report', April 2022.

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

[44] 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.

[45] 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.

[46] 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.

[47] Oakley Greenwood, 'CECV Methodology – Interim Report', April 2022.

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 2022-23). 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.

3.4 Annual updates

We are required to update CECVs annually. In the draft methodology we noted that, 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.

- 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.

We sought stakeholder views on the factors we should consider in updating CECVs annually.

3.4.1 Stakeholder responses

Several stakeholders suggested that we clarify what we mean by 'material changes' to assumptions in the ISP.[48]

[48] Including AusNet Services and CitiPower, Powercor and United Energy (available on the AER website).

3.4.2 Final decision

In determining whether there have been material changes to ISP assumptions, we will review AEMO's updated 'Inputs and assumptions' workbook each year. If input values (for any input listed in table 3.1) have materially changed in any year of the forecast period, we will re-estimate CECVs using the new assumptions. Other material changes could include a material revision to ISP scenarios developed by AEMO, a change in the scenario deemed to be most likely or large changes to key inputs to the most likely scenario such as fuel prices or major plant retirement.

In updating CECV estimates to account for inflation, we will use a CPI-X approach, where X is set to zero. This ensures that in economic terms, real values of CECV are maintained between reviews (in line with our approach to annual updates to VCRs).

To measure CPI changes we will apply the annual percentage change in the Australian Bureau of Statistics' (ABS) consumer price index (CPI) all groups, weighted average of eight capital cities, for the four quarters preceding the most recently reported figure.[49] For example, to publish annual adjustments by 1 July, we will use the reported CPI figures for the four quarters preceding March, which are the most recently reported figures available.

As well as publishing new CECV estimates by 1 July each year, we will publish an updated list of data sources used for model inputs.

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.[50]

In the draft methodology we suggested 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:

[49] ABS, Catalogue number 6401.0, Consumer price index, Australia. This measure is consistent with our approach to indexation employed elsewhere by the AER.

[50] NER rule 8.13(f).

- 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.[51]

We sought stakeholder views on potential triggers for reviewing the methodology prior to the five-yearly review.

3.5.1 Stakeholder responses

SA Power Networks suggested that material changes in the methodology, such as changes in the scope of wholesale market benefits captured (e.g. the range of ESS) should be undertaken by the AER prior to the commencement of each round of AER Distribution Determinations.[52] Similarly, Energy Queensland suggested that further refinement of wholesale energy costs and increased requirements to provide essential system services may be required as the energy market evolves.[53]

Both AusNet Services[54] and Ausgrid[55] suggested that we also review the methodology if:

- a material or systematic error is identified in the estimation of CECVs;
- the assumptions underpinning the estimation of CECVs are materially revised; or
- the ISP scenarios developed by AEMO are materially revised.

3.5.2 Final decision

We recognise the importance of providing DNSPs with sufficient time to consider material changes to the methodology and values, so that they can plan their regulatory proposals and consult with their customers. We consider that material revisions to ISP scenarios can be reflected in annual updates to CECVs (based on the approach outlined in section 3.4).

Under the final methodology, we will review the CECV methodology prior to the five-yearly review if:

- there is new information to support the inclusion of new wholesale market value streams in the methodology, e.g.:
  - reliable data on the timing and extent of export curtailment becomes available so that the avoided generation capacity investment value stream can be estimated with confidence.
  - new ESS markets develop and there is evidence that the alleviation of DER export curtailment will provide material benefits in these markets.

[51] Oakley Greenwood, 'CECV Methodology – Interim Report', April 2022.

[52] SA Power Networks, 'Submission to the draft customer export curtailment value methodology', May 2022.

[53] Energy Queensland, 'Submission to the draft customer export curtailment value methodology', May 2022.

[54] AusNet Services, 'Submission to the draft customer export curtailment value methodology', May 2022.

[55] Ausgrid, 'Submission to the draft customer export curtailment value methodology', May 2022.

- there is new information to support adopting a new approach to quantifying wholesale market value streams (either shorthand or longhand).
- a material or systematic error is identified in the estimation of CECVs.

We will consider the timing of future reviews to ensure that DNSPs have sufficient time to input values derived under the updated methodology in their regulatory proposals. To provide certainty, we will not review the CECV methodology more than once in a 12-month period.

4 Application of CECV

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 discuss possible options for DNSPs to apply CECVs in practice. We detail a model developed for DNSPs to easily aggregate the estimate CECVs and quantify the contribution of CECVs to the overall benefit of proposed DER integration investments.

4.1 Overview of the DNSP model

In the draft methodology we introduced the concept of the DNSP model and sought stakeholder views on the options provided to DNSPs for aggregating CECVs in practice.

4.1.1 Stakeholder submissions

Energy Queensland suggested that it would be more useful for the workbook to contain a single column of half hourly data such that the alleviation profile could be added in the adjacent column. It requested clarity as to whether other types of generation were considered, as the characteristic days appear to be only dependent on demand and solar PV generation. It also suggested that the benefit of the ranked characteristic days approach over the regular characteristic days approach was unclear, given the data requirements for DNSPs.[56]

AusNet Services noted that it supports DNSPs have the flexibility to choose the approach they consider most appropriate. If DNSP choice is to be removed and characteristic days are to be the default approach, DNSPs should have the ability to rank days. It also noted that if the AER decides to rank days, it should publish the factors it considers when making its decision.[57] Similarly, Ausgrid submitted that applying the characteristic day approach should not be mandatory. It also suggested that DNSPs be allowed to re-rank characteristic days based on their own information.[58]

SA Power Networks questioned the need to develop the DNSP model and noted its preference is that DNSPs have discretion to create their own model. It suggested that this approach is likely to be more efficient and would provide greater insights when comparing investment options.[59]

The Consumer Challenge Panel noted its concern that the proposed flexibility in giving DNSPs three different approaches to modelling aggregate CECVs could reduce the overall

[56] Energy Queensland, 'Submission to the draft customer export curtailment value methodology', May 2022.

[57] AusNet Services, 'Submission to the draft customer export curtailment value methodology', May 2022.

[58] Ausgrid, 'Submission to the draft customer export curtailment value methodology', May 2022.

[59] SA Power Networks, 'Submission to the draft customer export curtailment value methodology', May 2022.

transparency in the application of CECVs. It suggested that we explicitly specify which subgroup of investments designed to reduce export curtailment may use each of the three methodologies.

4.1.2 Final decision

The DNSP will need, as a minimum, to estimate the amount of curtailment and the number of days on which that curtailment will occur. The DNSP model does not prescribe how DNSPs establish these inputs. These inputs would be required no matter what approach is adopted for estimating the value of reduced curtailment because it is fundamental to any evaluation of a project to increase DER hosting capacity.

Beyond this, there is no requirement for a DNSP to use any particular option contained in the DNSP model – they are free to choose whichever option they choose, including whichever method they feel is easiest to use.

The intent of the DNSP model is to provide the DNSP with the choice of three methods for assessing the CECV benefit of their alleviation projects. No mandating of one or another approach is foreseen. Similarly, we will provide a ranking of the characteristic days for each jurisdiction along with how the rankings were assigned. DNSPs may feel that a different ranking would be more appropriate for their service areas based on differences between the jurisdiction as a whole and conditions within their service area. However, the DNSP would be expected to provide the rationale for that alternative ranking. Therefore, DNSPs are free to input the published CECVs into their own models, provided that these are transparent and reviewable.

Using the characteristic day approach will not be mandatory. The DNSP model will provide the actual half-hourly CECVs for each half hour in each NEM region over the entire course of the analysis timeframe as part of the DNSP model. The DNSPs are free to use these directly in their assessment of the value that will be created by their hosting capacity projects.

In addition, it should be noted that while the DNSP will include a set of ranked characteristic days for each region, the DNSP will be able to re-rank the days where they have reason to do so. The AER will expect the DNSP to provide a rationale for any such re-ordering.

The three different methods in the DNSP model are provided to give the DNSP flexibility in how granularly they wish to define the alleviation profile of a given project. The motivation was to let the DNSP match the method to the amount of information/detail they feel able to provide about each alleviation project. They were not developed to be applied to different types of alleviation projects.

In the following sections we detail the DNSP model under the final CECV methodology.

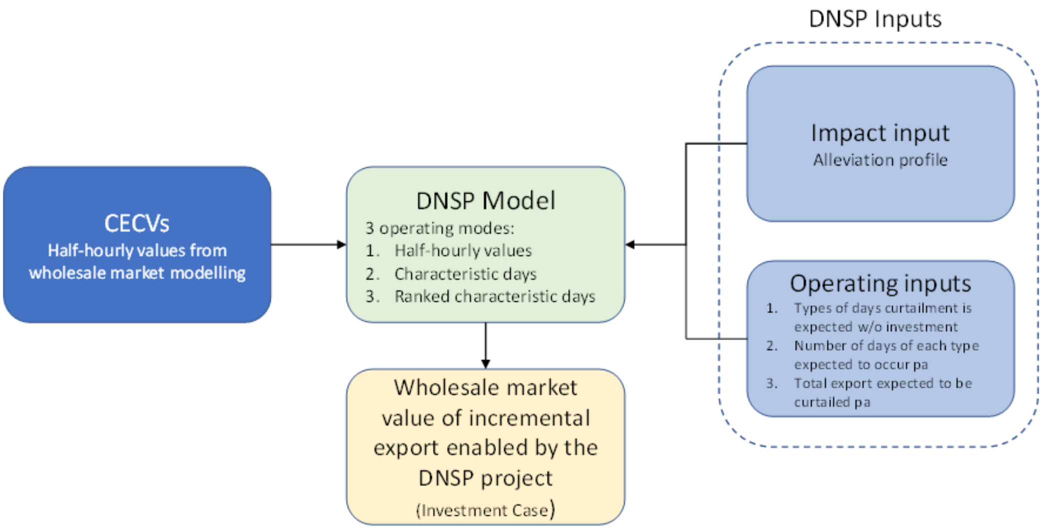
Model purpose

The DNSP model (represented in Figure 4.1) 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

DNSP model inputs

CECVs

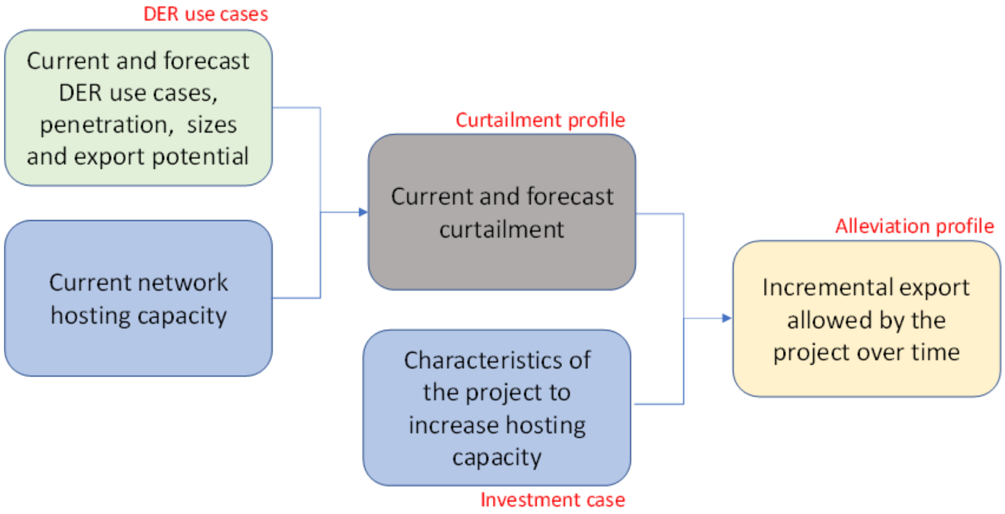
The CECVs are the raw, half-hourly values estimated over a 20-year period, as per the CECV methodology.

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 affects 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 of curtailment that 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 that are in place or are 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 from 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 be needed 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 have a significant impact on 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).

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.

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). This approach allows DNSPs to input into the model an alleviation profile that is more highly aggregated than would be required in the self-selection of half-hourly values approach.

Characteristic days 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. A high, medium and low level is provided for each of the two factors, resulting in there being nine characteristic day types within the model. The DNSP can define the thresholds for the three levels of each of the factors. The DNSP can also select the hours during which alleviation will be provided by the project it is proposing.

The model automatically calculates and reports for each region and for each year of the analysis horizon:

- the number of days that each type of characteristic day occurs
- the average marginal cost of wholesale electricity on each type of characteristic day.

Tables 4.2 and 4.3 below provide examples of the output of the model for two different characteristic days.

Table 4.2: Example of model output for a High Solar output, Low Demand characteristic day

Average price in middle of the day based on High Solar Output and Low demand			
Summer	Autumn	Winter	Spring
[redacted]			
$ 23.32	$ -	$ 24.51	$ 23.44
$ 24.26	$ 25.55	$ 25.40	$ 22.19
$ 23.12	$ 24.49	$ 22.51	$ 19.32
$ 23.42	$ 22.19	$ 16.02	$ 14.33
$ 24.77	$ 26.35	$ 20.08	$ 15.09
$ 16.63	$ 22.99	$ 13.06	$ 6.54
$ 9.28	$ 17.28	$ 5.96	$ 1.31
$ 2.73	$ 9.30	$ 4.94	$ 0.37
$ 1.38	$ 5.92	$ 3.70	$ 0.16
$ 0.87	$ 5.68	$ 3.97	$ 0.51
$ 0.14	$ 3.83	$ 2.20	$ -
$ 0.16	$ 10.01	$ 8.33	$ -
$ 0.17	$ 10.25	$ 7.17	$ -
$ 0.13	$ 10.01	$ 1.75	$ 0.27
$ -	$ 2.16	$ 0.69	$ 0.09
$ -	$ 0.50	$ 1.38	$ -
$ -	$ -	$ 1.08	$ -
$ -	$ 6.97	$ 3.73	$ -
$ -	$ 4.88	$ 0.12	$ 0.09
$ -	$ 0.48	$ -	$ 0.03
$ -	$ -	$ 13.77	$ -
$ 7.16	$ 9.94	$ 8.59	$ 4.94

Source: Oakley Greenwood

Table 4.3: Example of model output for a Medium Solar Output, Low Demand characteristic day

Average price in middle of the day based on Medium Solar Output and Low demand			
Summer	Autumn	Winter	Spring
$ 25.41	$ -	$ 25.85	$ 23.45
$ 25.42	$ 26.65	$ 26.60	$ 22.38
$ 23.39	$ 24.53	$ 23.30	$ 19.33
$ 23.81	$ 22.90	$ 19.07	$ 17.81
$ 24.32	$ 27.58	$ 22.99	$ 15.60
$ 14.44	$ 27.71	$ 19.30	$ 11.44
$ 7.17	$ 23.88	$ 10.15	$ 2.55
$ 5.54	$ 12.93	$ 8.58	$ 0.03
$ 4.60	$ 11.88	$ 6.71	$ 0.12
$ 3.00	$ 13.68	$ 7.17	$ 0.29
$ 0.86	$ 10.85	$ 3.99	$ -
$ 1.70	$ 10.04	$ 9.41	$ -
$ 1.36	$ 8.94	$ 12.91	$ -
$ -	$ 7.57	$ 10.65	$ -
$ 0.32	$ 6.04	$ 7.56	$ -
$ 0.16	$ 1.85	$ 7.02	$ -
$ -	$ 0.26	$ 8.48	$ -
$ -	$ 0.40	$ -	$ -
$ -	$ 4.09	$ -	$ -
$ -	$ 1.23	$ -	$ -
$ -	$ 0.06	$ 40.25	$ -
$ 7.69	$ 11.58	$ 12.86	$ 5.38

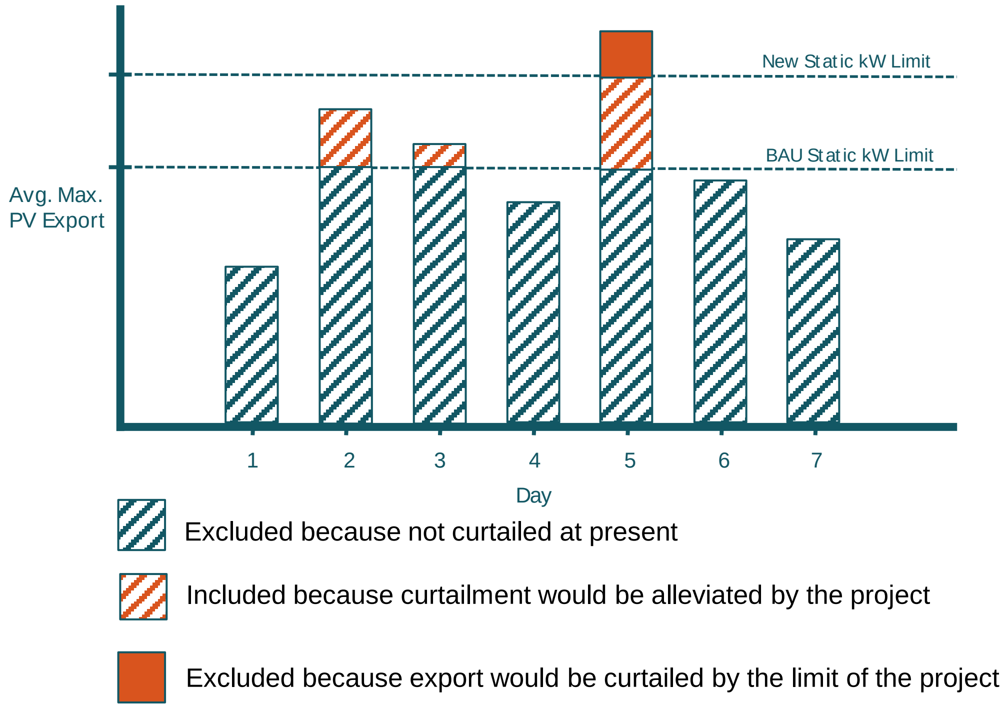
Source: Oakley Greenwood

Characteristic day information will be categorised by:

- NEM region
- Year
- Season
- Time of day when solar curtailment will generally occur (e.g., 12pm to 3.30pm with specific times able to be selected by the DNSP)[60]
- Static limits on PV export (e.g., 5kW, 4kW, 3kW which can be input into the model on a project-by-project basis). The specification of a static limit will exclude all days where the maximum rooftop solar PV production (in the market modelling) does not reach that limit (e.g., a 5kW static limit 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.

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

Figure 4.3: Modelling of incremental export above an existing or new static export limit



Source: Oakley Greenwood

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.[61]

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.

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).

[61] Oakley Greenwood, 'CECV Methodology – Final Report', June 2022.

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.

Example of the ranked characteristic day concept

DNSP proposes investment to reduce export curtailment due to voltage issues

The DNSP would provide the following inputs, for each year:

- The total estimated amount of additional energy released because of the investment (e.g., 100MWh), and
- The number of days when curtailment would likely have been needed absent the project (e.g., 25 days).
- The model will automatically allocate the amount alleviated in each year to characteristic day types based on their ranking (as opposed to the DNSP doing this under Option 2) and calculate the wholesale market value.

Table 4.4: Example of the use of ranking to determine average wholesale costs

Summary Outputs - Ranked Days	Spring	Autumn	Autumn	Spring	Spring	Autumn	Spring	Autumn
Year↓ / Rank →	1	2	3	4	5	6	7	8
2021								
2022	$ 23.44	$ -	$ -	$ 23.45	$ 25.36	$ -	$ 25.65	$ -
2023	$ 22.19	$ 25.55	$ 26.65	$ 22.38	$ 23.55	$ 32.59	$ 24.66	$ 32.71
2024	$ 19.32	$ 24.49	$ 24.53	$ 19.33	$ 22.02	$ 28.00	$ 22.14	$ 30.34
2025	$ 14.33	$ 22.19	$ 22.90	$ 17.81	$ 18.76	$ 24.14	$ 17.94	$ 26.09
2026	$ 15.09	$ 26.35	$ 27.58	$ 15.60	$ 20.11	$ 29.73	$ 20.57	$ 31.57
2027	$ 6.54	$ 22.99	$ 27.71	$ 11.44	$ 9.20	$ 28.48	$ 15.34	$ 32.40
2028	$ 1.31	$ 17.28	$ 23.88	$ 2.55	$ 2.78	$ 26.34	$ 5.57	$ 25.75
2029	$ 0.37	$ 9.30	$ 12.93	$ 0.03	$ 2.36	$ 24.75	$ 6.38	$ 19.95
2030	$ 0.16	$ 5.92	$ 11.88	$ 0.12	$ 1.39	$ 14.64	$ 4.89	$ 20.45
2031	$ 0.51	$ 5.68	$ 13.68	$ 0.29	$ 1.06	$ 16.61	$ 3.88	$ 20.91
2032	$ -	$ 3.83	$ 10.85	$ -	$ -	$ 10.59	$ 2.36	$ 15.64
2033	$ -	$ 10.01	$ 10.04	$ -	$ -	$ 20.05	$ 2.55	$ 11.67
2034	$ -	$ 10.25	$ 8.94	$ -	$ -	$ 30.19	$ 2.87	$ 9.46
2035	$ 0.27	$ 10.01	$ 7.57	$ -	$ 0.69	$ 31.04	$ 5.66	$ 8.95
2036	$ 0.09	$ 2.16	$ 6.04	$ -	$ -	$ 4.13	$ 3.71	$ 19.19
2037	$ -	$ 0.50	$ 1.85	$ -	$ 0.23	$ 0.65	$ 1.45	$ 15.47
2038	$ -	$ -	$ 0.26	$ -	$ -	$ -	$ 0.09	$ 9.73
2039	$ -	$ 6.97	$ 0.40	$ -	$ -	$ 7.34	$ 0.15	$ 1.48
2040	$ 0.09	$ 4.88	$ 4.09	$ -	$ -	$ 25.83	$ 2.85	$ 5.52
2041	$ 0.03	$ 0.48	$ 1.23	$ -	$ -	$ -	$ 0.62	$ 12.79
2042	$ -	$ -	$ 0.06	$ -	$ -	$ -	$ -	$ 5.19

Source: Oakley Greenwood

The characteristics of the ranked days shown in Table 4.4 are:

Rank 1. High Solar Output and Low demand – Spring

Rank 2. High Solar Output and Low demand – Autumn

Rank 3. Medium Solar Output and Low demand – Spring

Rank 4. Medium Solar Output and Low demand – Autumn

Rank 5. High Solar Output and Medium demand – Spring

Rank 6. High Solar Output and Medium demand – Autumn

Rank 7. Medium Solar Output and Medium demand – Spring

Rank 8. Medium Solar Output and Medium demand – Autumn

The number of days allocated to each of those ranked days in the model is shown in **Error! Reference source not found.** 4.5 below.

Table 4.5: Number of days allocated to each ranked day

Summary Outputs - Ranked Days	Spring	Autumn	Autumn	Spring	Spring	Autumn	Spring	Autumn
Year↓ / Rank →	1	2	3	4	5	6	7	8
2021								
2022	10.00	0.00	0.00	17.00	8.00	0.00	27.00	0.00
2023	14.00	13.00	13.00	13.00	4.00	3.00	31.00	30.00
2024	10.00	14.00	14.00	17.00	8.00	4.00	28.00	29.00
2025	13.00	14.00	14.00	14.00	5.00	4.00	31.00	29.00
2026	14.00	14.00	14.00	13.00	4.00	5.00	33.00	29.00
2027	12.00	13.00	15.00	15.00	6.00	6.00	31.00	27.00
2028	14.00	14.00	14.00	13.00	4.00	5.00	32.00	29.00
2029	14.00	13.00	15.00	13.00	4.00	6.00	33.00	28.00
2030	14.00	13.00	15.00	13.00	4.00	6.00	33.00	29.00
2031	12.00	14.00	14.00	15.00	6.00	5.00	31.00	30.00
2032	14.00	14.00	14.00	13.00	4.00	5.00	33.00	29.00
2033	14.00	14.00	14.00	13.00	4.00	5.00	32.00	30.00
2034	13.00	14.00	14.00	14.00	5.00	5.00	31.00	30.00
2035	13.00	13.00	15.00	14.00	5.00	6.00	32.00	29.00
2036	13.00	14.00	14.00	14.00	5.00	5.00	32.00	30.00
2037	14.00	14.00	14.00	13.00	4.00	5.00	33.00	28.00
2038	14.00	14.00	14.00	13.00	4.00	5.00	33.00	29.00
2039	15.00	13.00	15.00	12.00	3.00	6.00	33.00	29.00
2040	15.00	11.00	17.00	12.00	3.00	8.00	34.00	26.00
2041	14.00	13.00	15.00	13.00	4.00	6.00	33.00	28.00
2042	0.00	14.00	14.00	0.00	0.00	5.00	0.00	29.00

Source: Oakley Greenwood

Having regard to the two components of information presented above, if a:

- DNSP was forecasting 100,000MWh of alleviation across 10 days in 2026, the number of days would fall below the number of days attributed to the first ranked day type in that year (as there are 14 days in the model), hence the average price for that ranked day type of $15.09 would be applied to all that volume of alleviation
- DNSP was forecasting 120,000MWh of alleviation across 15 days in 2027, the number of days would exceed the number of days attributed to the first ranked day type in that year in the model (12 days), however, it does not exceed the total number of days attributable to the 1st and 2nd ranked day types combined, therefore:
    - 12/15 of the 120,000/MWh is attributed to the first ranked day type in that year (so the total CECV is 12/15*120,000MWh*$6.54/MWh); and
    - The remaining 3/15 of the 120,000/MWh that is estimated to be alleviated is attributed to the second ranked day type in that year (so the CECV is 3/15*120,000MWh*$22.99/MWh).

- DNSP was forecasting 142,000MWh of alleviation across 30 days in 2028, the number of days exceeds the number of days attributed to the combined number of days attributed to the first and second ranked day types in that year in the model (14 days plus 14 days), but does not exceed to the total number of days attributable to the 1st, 2nd and 3rd ranked day types, therefore:
    - 14/30 of the 142,000/MWh is attributed to the first ranked day type in that year (so the CECV is 14/30*142,000MWh*$1.31/MWh)
    - 14/30 of the of the 142,000/MWh is attributed to the second ranked day type in that year (so the value is 14/30*142,000MWh*$17.28/MWh); and
    - The remaining 2/30 of the of the 142,000/MWh is attributed to the third ranked day type in that year (so the value is 2/30*142,000MWh*$23.88/MWh)

and so on and so forth.

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).

Appendix A: Stakeholder submissions

ID	Theme	Stakeholder	Comment	Response
1.1	DER value streams	Simply Energy	The CECV should ideally capture all possible Distributed Energy Resources (DER) value streams (as summarised in table 2.1 of the explanatory statement). However, we acknowledge there is a possibility of wide variations in ‘network sector’ value streams, which may necessitate distribution businesses estimating some value streams outside of the CECV. At a minimum, we would expect that the CECV capture the ‘wholesale market’ and ‘customer’ value streams.	In developing the CECV methodology we have sought to quantify customer benefits in the wholesale market, as they are likely to represent a material benefit which can be estimated in a relatively consistent manner. We have not accounted for avoided costs associated with future generation capacity investment, as these are likely to be immaterial and cannot be estimated with sufficient certainty. We also do not estimate the ‘customer’ value stream, as this captures the costs and benefits associated with changes in customer demand for DER. Estimating these values relies on assumptions about the nature of network investments and the response of customers to these investments.
1.2	DER value streams	AusNet Services	A more holistic approach - one that reflects customer-centric decision making - should apply when considering DER investment decisions.	In addition to using CECVs to quantify benefits in the wholesale market, DNSPs are permitted to quantify other DER value streams (under our DER integration expenditure guidance note). Also, under our guidance note it is possible for DNSPs to quantify other value streams (based on customer willingness to pay) under certain conditions.
1.3	DER value streams	CitiPower, Powercor, United Energy	While we agree that the wholesale value streams are likely to be the most material DER value streams, the draft CECV methodology will undervalue the CECV if it does not capture other customer value streams that are important and meaningful to customers. Including additional value streams, so long as they are quantifiable, evidence-based and valued by customers, would more accurately reflect the value that customers place on export services and is likely to result in a more efficient level of export service delivery.	Potential “other” customer values are not captured in the CECV methodology. Under our DER integration expenditure guidance note it is possible for DNSPs to quantify other value streams (based on customer willingness to pay) under certain conditions.
1.4	DER value streams	CitiPower, Powercor, United Energy	If the AER does not include customer values in the CECV, then it should at a minimum explicitly allow networks to include customer preferences within the benefits case under its DER integration guideline if these can be demonstrated to reflect the views of the DNSPs’ customer base through customer research. This second-best approach is likely to support an efficient level of investment to meet customer	See previous response.

ID	Theme	Stakeholder	Comment	Response
			preferences and would allow DNSPs to deliver on customer expectations for network services. However, this approach is second-best to direct inclusion within the CECV methodology because customer preferences are directly linked to how customers value services, in this case export services.	
1.5	DER value streams	SA Power Networks	To align network expenditure on DER hosting capacity with customer expectations: • the CECV, as proposed in the Draft Methodology, should only form a starting point or floor value because it is only valuing the effect on the NEM wholesale market, which all customers (including those without DER) ultimately experience, and indeed only some value streams; • there should also be the option of considering other categories of value that are shared by all customers, as described in Table 2.1 the Draft Explanatory Statement, including network value (e.g. losses), upstream network value (e.g. changes in transmission network investment) and other wholesale market value (e.g. changes in NEM generator capacity investment); and • distributors should then be able to undertake engagement and research, on the extent to which customers, particularly those with DER, are willing to pay for higher levels of network hosting capacity - this research, may seek to express in dollar terms, customers perceived financial and non-financial benefits (e.g. energy flexibility, and / or environmental benefits, etc) of exporting their DER energy.	See response to 1.2.
1.6	DER value streams	SA Power Networks	While the AER discounts the validity of valuing environmental benefits, either directly via the CECV or indirectly via customer willingness to pay, we think this position needs further consideration noting that: • even without a formally legislated emissions reduction policy in place, environmental considerations are implicitly included in the AEMO ISP assumptions (i.e. the emissions trajectories in the scenarios are consistent with a target of net zero emissions by 2050); and • while we are yet to undertake customer value research to express value in monetary terms, we consider it likely, based on our broader qualitative research to date,	Our DER integration expenditure guidance note provides the conditions under which environmental benefits may be quantified.

ID	Theme	Stakeholder	Comment	Response
			that customers may value environmental outcomes highly and independently of the decisions of policy makers.	
1.7	DER value streams	Public Interest Advocacy Centre	PIAC supports a level of prescription and consistency in the approach to estimating and applying Customer Export Curtailment Values (CECVs). However, this should not limit the potential for DNSP proposals to be informed by consumer preferences derived from engagement with consumers and consumer representatives. PIAC recommends the AER considers providing guidance to DNSPs on how the CECV requirements interact with requirements for engagement and consumer preferences.	See response to 1.2.
1.8	DER value streams	Public Interest Advocacy Centre	PIAC questions whether the blanket exclusion of capital investment in networks and generation accurately reflects the value of export. For example, it is reasonable to assume customer exports that are not responsive to negative wholesale prices may result in avoided or deferred investment in solar farms, which are responsive to wholesale prices. This would result in less efficient investment. On the other hand, exports may make some contribution to avoided network asset derating and/or deferring replacement in those parts of the distribution and sub-transmission network with low solar saturation due to high density housing and/or more C and I load.	Our modelling is based on a resource-cost assessment using SRMC-based dispatch. Therefore, VRE will be economically curtailed at $0/MWh and will not be producing during negative prices in our model. We agree that there might be avoided investment cost due to DER export. However, as we explained in our detailed response to ENA, one needs to know the alleviation profile to reliably quantify the avoided generation investment cost. Further, we have demonstrated in our response that the avoided generation investment cost due to rooftop PV export curtailment is unlikely to be material. This is because curtailment of rooftop PV export will likely take place when wholesale generation cost is already at zero, due to the correlation between utility and distributed solar generation patterns. It should also be noted that the model does not exclude consideration of reductions or deferrals in network capital investment. Those cannot be included in the wholesale simulation modelling, however, and we have made an explicit statement that any such benefits that curtailment alleviation provides to the network itself should be added by the DNSP the values generated by the DNSP model.
1.9	DER value streams	Ausgrid	The AER's CECVs should include avoided investment costs. We encourage the AER to consider including this value stream as part of its CECV methodology.	We consider that there is still insufficient evidence to suggest that avoided investment costs are both material and able to be quantified with confidence (see section 2.1).

ID	Theme	Stakeholder	Comment	Response
			We recommend that upon publishing the final CECVs, the AER work within the remainder of 2022 to revise the CECVs for 2023 so that thy include the avoided investment costs.	Although excluded from CECVs, DNSPs are permitted to quantify these values when proposing DER integration expenditure. We intend to update CECVs for 2023 based on our approach to annual updates (section 3.4) and we will update the CECV methodology prior to the five-yearly review if triggers are met (section 3.5).
1.10	DER value streams	ENA / HoustonKemp	The methodology produces a granular and sophisticated estimation of only a portion of the benefits and excludes a material component, i.e., the benefits arising from avoiding generation capacity investment – or 'investment benefits' - thereby risking materially underestimating the CECV.	Oakley Greenwood has provided a detailed response to the concerns raised by HoustonKemp's memo.
2.1	Export curtailment and alleviation profile	Energy Queensland	Suggest that while the hosting capacity and future capacity are profiles in the Consultation, the operational methodology most DNSPs use is likely to be static values which may only change on a seasonable basis. The complexity that an alleviation profile requires to assess data (current and forecast penetration, sizes, export potential, amount and timing of curtailment), compared to using a generation duration curve scaled to the installed capacity and determining mathematically the percentage of time curtailment would occur based on existing and future hosting capacity, will not, in our view, necessarily provide added benefit.	See section 2.2.2: If DNSPs are unable to credibly estimate the timing and volume of additional DER exports enabled by their proposed investments, their customers will not realise the benefits of efficient DER integration. Given the likelihood that wholesale market benefits (derived with CECVs) will represent a significant portion of the claimed benefits in a cost-benefit analysis, it is reasonable for customers to expect that DNSPs have thoroughly considered the quantity and time distribution of DER exports it expects its proposed investment will provide.
2.2	Export curtailment and alleviation profile	AusNet Services	While the alleviation profile concept is sound in principle, developing a profile for each proposed investment will be a complex exercise and each DNSP is likely to approach this issue slightly differently. Its use is also likely to impose additional resource requirements and DNSPs will need additional resources (and time) to develop, embed and then refine this process.	See response to 2.1.
2.3	Export curtailment and alleviation profile	Ausgrid	Ausgrid supports the concept of the alleviation profile in principle, but note that the alleviation of curtailment may be achieved through DER enablement investments e.g. better low voltage visibility and modelling which allows for a relaxation of technical controls. We support grounding the assessment of the relative costs and benefits of investment in the customer experience. The development of alleviation profiles is prefaced on an assumed level of visibility of low voltage networks and hosting capacity. While we undertake	See response to 2.1.

ID	Theme	Stakeholder	Comment	Response
			detailed modelling of low voltage network, there are limitations inherent in any modelling exercise and consequently the alleviation generated by any given investment may depart from modelled alleviation. Accordingly, while we support the proposal to clearly link the alleviation impact of proposed investments to the quantified benefits of addressing curtailment, we note that the level of initial modelling sophistication may vary. Modelling will improve over time as alleviation profiles become a common input into investment forecasting.	
2.4	Export curtailment and alleviation profile	Consumer Challenge Panel	In developing the (alleviation) profile, issues such as forecast penetration and the consumer's view of curtailment versus incentives to self-consume will be highly variable, and subject to many influences. Should the alleviation profile be accepted, it is critical that in the early stages the AER is highly vigilant in examining how DNSPs establish the inputs. Over time, a guidance note to establish some accepted practices may be necessary.	We recognise that there may be variability in assumptions used to develop alleviation profiles. Our assessment of proposed alleviation profiles will consider the DNSP's ability to explain and detail the factors listed in section 2.2, including its understanding of network hosting capacity (over time) and the nature of the proposed investment(s) intended to alleviate export curtailment.
2.5	Export curtailment and alleviation profile	Consumer Challenge Panel	In light of the relatively long time horizon involved, the AER should consider featuring robustness checks when the DNSP model is used to produce alleviation profiles. This can be achieved by requiring DNSPs to vary key parameters featured in Table 3.1 (Model inputs) in the draft report when making the case for DER Investment. For example, given the current volatility in fuel prices, it would make sense for DNSPs to report how the alleviation profile of projects change if fuel prices vary by 10 or 20 per cent. If the alleviation profile is found to be sensitive to key parameter input, DNSPs should address these risks when reporting the alleviation profile.	See section 2.2.
4.1	Form of estimates	Energy Queensland	More granularity is unlikely to provide additional insight. Less granularity would not materially impact the accuracy of the benefit calculation. Suggest a single average value should be provided for CECV for each year of the forecast, similar to what is used for Value of Customer Reliability. Providing further granularity does not significantly increase the accuracy but adds significantly to the complexity. We would appreciate a worked example demonstrating the significance of more granular values to justify the additional effort required to use half hourly values.	The CECV is inherently a half-hourly value. It is possible for different alleviation projects to enable the same amount (MWh) of incremental export, but very different half-hourly profiles and therefore different values in terms of upstream benefit. This would not be reflected if a single, average CECV were applied to those different projects. We note that the DNSP model provides the user with the ability to use a somewhat averaged CECV

ID	Theme	Stakeholder	Comment	Response
				figure through the provision of characteristic days. The approach contained in the DNSP model is a reasonable compromise between the accuracy and effort required by a fully half-hourly specified alleviation profile and the over-simplification and inaccuracy that a single annual CECV would entail.
4.2	Form of estimates	Simply Energy	Distribution businesses should retain the ability to obtain location specific CECV's where there are significant variations that contrast with remaining network characteristics (for example, significantly higher or lower rooftop solar PV installations).	See section 3.2.2: It is not clear how DNSPs would estimate CECVs at a more granular level, given that CECVs are estimated using electricity market modelling of the NEM dispatch. In any case, we consider that CECVs applied by DNSPs should be estimated in a consistent manner under our methodology.
4.3	Form of estimates	Red Energy, Lumo Energy	CECVs would need to be captured at five-minute intervals consistent with the NEM dispatch process to capture the value of curtailment values more accurately.	See section 3.1.2: While we agree that estimating CECVs at five-minute intervals is consistent with the NEM dispatch process, this approach would require us to make assumptions about AEMO's demand forecast and variable renewable energy traces, which are not available at this level of granularity. In any case, 5-minute CECVs would only be beneficial if DNSPs were developing alleviation profiles were also at the 5-minute level, or the 5-minute values could be expected to produce materially different CECVs for the characteristic days (discussed in section 4). We do not consider this to be likely, and so are satisfied that half-hourly values are sufficient.
4.4	Form of estimates	Red Energy, Lumo Energy	CECVs should be developed on an intra-regional level reflecting demand at the regional level. By doing this, the CECV methodology would more accurately reflect demand at the regional level improving the accuracy of the CECV's methodology's outputs in order to justify any augmentation.	See response to 4.2.
4.5	Form of estimates	Red Energy, Lumo Energy	CECVs should be published with upper and lower bounds for CECV values and include some accommodating analysis explaining the key drivers for results. Given the difficulty of relying on a single CECV, publishing upper and lower ranges for the CECV values would help understand how reliable the numbers would be.	We do not consider that publishing a range of CECVs is appropriate. This would add to complexity and reduce the certainty provided by us developing a methodology and estimating a single set of values. Oakley Greenwood's report discusses the drivers of CECVs in further detail, including fuel prices and time-of-day system demand shape.

ID	Theme	Stakeholder	Comment	Response
5.1	Modelling process	AusNet Services	While we recognise that the approach to inputs proposed by the AER will facilitate greater consistently across all DNSPs, we continue to consider that each DNSP should be able to propose alternative inputs should it deem them appropriate. The sensitivity of each input should be considered as this will provide a range of reasonable inputs to be assessed when undertaking this type of modelling.	See section 3.3.2: This suggestion implies that DNSPs will estimate CECVs themselves. We do not consider that there is value in DNSPs estimating their own values as we expect that they will apply our published CECVs.
5.2	Modelling process	Endeavour Energy	In practice, market modelling has limitations that should be considered before discounting the use of shorthand methods. This is not to suggest a fundamental change is required to the AER's draft CECV methodology. Instead, it highlights the value of having regard to multiple approaches to address the known limitations of any preferred approach. For instance, a longhand approach risks a lack of transparency around the mechanics of the model being used and the detailed input assumptions into the model – not insofar as AEMO's ISP assumptions, but assumptions around how investment and planning decisions are made internal to the model, as well as optimisation procedures and impacts on dispatch. Under a full market modelling approach, it can hard to distinguish the extent to which the estimates are driven by the market model design versus the input assumptions. Full-scale market models can produce substantially different results depending on these mechanics, and without full access to the model, DNSPs have uncertainty around whether the CECV estimates reflect a wide range of scenarios and views. An example of this poor transparency is the lack of reasoning for the low and volatile draft CECVs estimated post-2030 which we would expect to be larger and more stable against a backdrop of demand growth from a general trend towards more electrification and system transformation driving DER growth acceleration. Without a clear understanding of the factors underpinning these values, the view that market modelling provides accurate CECV inputs cannot be tested or challenged.	The market modelling methodology used in this project is the standard approach in wholesale market modelling. The modelling used AEMO's draft ISP inputs and the dispatch algorithm is consistent with AEMO's time-sequential dispatch model. Both have been well documented and extensively consulted on with a wide range of industry stakeholders in the ISP development process. The modelled CECV is steadily increasing after 2030 on a time-weighted average basis, reflecting higher average wholesale cost due to demand growth and electrification. However, the increasing solar penetration (from both the utility and the BTM sectors) mean the wholesale cost during high solar output periods will be low. This means CECV will be lower if curtailment alleviation coincides with high solar output periods.
5.3	Modelling process	Endeavour Energy	Consistent with good regulatory and investment practice, there may need to be consideration of sensitivities and ranged approaches to inputs in order to provide a confidence band of CECV	The Step Change scenario was chosen in the current round of modelling because it is considered the "most likely" scenario by stakeholders in the ISP

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			estimates rather than relying upon a single set of values over a long period. Deploying a wider range of different methodologies and approaches can provide more reference points and add credibility to the CECV estimates through addressing any concerns about biases, lack of transparency or inconsistencies when relying on a single approach. Suggest that modelling of additional scenarios would provide additional insight into the appropriate values for CECV given the sensitivity of estimates of the CECV to the scenario adopted, noting there is a high impact of system demand on the CECV estimates. It is unclear how this has been estimated in the current draft CECV estimates and we also note that the various ISP scenarios have substantially different views on demand from sources such as aggregated and disaggregated DER. This means that the draft methodology is potentially discounting high demand scenarios such as the high electrification “hydrogen superpower” ISP scenario, which could risk network underinvestment. It is plausible that future ISPs will introduce other scenarios which may be more likely to occur or even potentially rename the “step change” scenario as has been the case with other scenarios. Being bound to a single scenario will lose a large amount of flexibility in the CECV calculation. The AER should consider either providing estimates for other ISP scenarios or a weighted approach to account for the uncertainty which spans across all ISP scenario outcomes.	consultation process. In the future, the modelling could potentially use other scenarios (however named) in the relevant ISP cycle if they are considered to be the most likely scenario in the ISP consultation process. Publishing multiple profiles of half-hourly CECV based on multiple ISP scenarios could potentially introduce uncertainties regarding which profile should be used. An alternative option would be to average the profiles (for each half-hour) based on the ISP weighting of the scenarios. However, the weighted average approach is unlikely to produce significantly different CECVs for the following reasons: • The Step Change scenario is effectively the “central” scenario in the 2022 ISP and has more than 50% weighting. A weighted average across all scenarios is unlikely to lead to significantly different estimate. • In practice, export curtailment relates predominantly to rooftop PV, at least in the near future. In all ISP scenarios there is strong uptake of utility and BTM solar, which means the value of wholesale market cost when rooftop PV is curtailed will be very low regardless of the scenarios modelled, or how their results are combined. The current methodology allows the DNSPs to apply their own alleviation profile based on specific projects against the estimated half-hourly CECVs. In doing so, it ensures the most critical value driver is not tied to any wholesale or DER uptake assumptions in the ISPs but reflects the specific circumstances and design of the project.
5.4	Modelling process	Consumer Challenge Panel	Regarding the proposal to run a single simulation using POE50 demand traces, it would be interesting to see if the benefits of reduced export curtailment would have a larger impact under POE10 peak demand when the network is under more operational pressure. This would help ensure that the CECV reflects avoided generation capacity investment as well as transmission capacity investment. Transmission expansion is usually	Using a POE10 demand trace will likely increase the wholesale market cost, and hence half-hourly CECVs, during system peak demand periods. However, as discussed elsewhere, currently DER export curtailment is primarily caused by curtailment of rooftop PV. System peak demand predominantly occurs during periods of low or zero rooftop PV output. This means that, in practice, the higher wholesale market costs during system peak will have no

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			assessed against POE10 peak demand.	impact on the value of curtailment alleviation as there is generally no curtailment during these periods.
5.5	Modelling process	Public Interest Advocacy Centre	It appears from the draft paper that the modelling input for headroom is intended to be fixed at 944MW for 20 years in the dispatch model. This is presumably predicated on the largest operating thermal generation unit in 2022 (for the first CECV assessment). If this understanding is correct, PIAC requests the AER to confirm if, according to the relevant scenario in the 2022 ISP, the current largest thermal generation unit is still expected to be operating at the same capacity in 2042. If this is not the case, PIAC recommends the AER consider reducing the headroom value throughout the 20year dataset in keeping with the latest forecasts of generator retirements and deratings in that period.	The model used a 944 MW NEM-wide headroom in the model to approximate the total contingency and regulation raise requirements, noting in practice they are dynamic numbers that could be affected by the actual market condition. In the current market, the 944 MW headroom is equal to the largest generating unit (Kogan Creek at ~750MW) plus a static raise regulation requirement. While Kogan Creek is forecast to retire before 2042 in the draft 2022 ISP, it is not clear how AEMO will change contingency and regulation raise demand in the future in response to increasing variability due to rapid VRE uptake. In the absence of any definitive information on how AEMO will change FCAS requirements in the future energy system, we have undertaken a conservative approach by not changing the headroom assumption in our model. By 2042, the largest generating unit according to the draft 2022 ISP modelling will be Tallawarra (~440MW). Even if we adjusted the NEM-wide headroom requirements down by 310 MW (750 MW – 440 MW), the impact on the estimated half-hourly CECV would be negligible.
5.6	Modelling process	ENA / HoustonKemp	The AER's draft CECVs are inconsistent with projected investments in the Integrated System Plan.	See Oakley Greenwood’s response to ENA/HoustonKemp submission.
5.7	Modelling process	ENA / HoustonKemp	The CECV estimation approach involves methodological assumptions that tend to underestimate the CECV. have identified three additional methodological factors that appear to be driving the conservative and low estimates of the CECV within the modelling undertaken by OGW: • Approach to the estimation of marginal cost OGW's approach (to the modelling of batteries) correctly recognises the importance of the concept of opportunity cost for the marginal costs of storage and some of the implications of this concept for modelling avoided dispatch costs. However, based on this description, it appears that OGW’s modelling only considers the alternative generation in each period in isolation, rather than the highest cost alternative across a foresight period, e.g., a day. In	See Oakley Greenwood’s response to ENA/HoustonKemp submission.

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			this circumstance the number of cycles does not necessarily change. • Consistency of dispatch outcomes with emissions trajectories It appears that the approach adopted by OGW to the dispatch modelling involves adopting the capacity values for coal plants and then dispatching the market on the basis of short run marginal costs. This approach will lead to a scenario where the output from coal plants is higher than would otherwise occur in the presence of emissions constraints and where the level of emissions will be inconsistent between AEMO's ISP modelling to project capacity investment and the dispatch modelling conducted by OGW. • Application of average outage factors OGW apply an averaged outage rate across all periods, rather than use a sequence of projected outage status values. The later approach is adopted in the modelling undertaken in AEMO's Electricity Statement of Opportunities, albeit with numerous simulation runs.	
6.1	Updates to values and methodology	AusNet Services	If the AER is to have discretion as to whether it will update inputs other than inflation based on its assessment of materiality, the AER should make public the factors it will consider when making its decision. This will ensure a 'no surprise' environment and greater transparency – outcomes we expect the AER will be willing to embrace. The CECV methodology should be reviewed prior to the five-yearly review given the rapid rate of DER integration and speed of transition. In addition to the factors identified by the AER, the CECV methodology should be subject to a review prior to the five-yearly review if: • a material error is identified in the estimation of CECVs; • the assumptions underpinning the estimation of CECVs are materially revised; • the integrated system plan scenarios developed by the Australian Energy Market Operator (AEMO) are materially revised. The AER should provide sufficient time for consultation where changes to the proposed methodology are being proposed.	See sections 3.4 and 3.5.

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6.2	Updates to values and methodology	CitiPower, Powercor, United Energy	The AER should support a pragmatic approach to application of updates to the CECVs in circumstances where proposed investments have been thoroughly consulted on and are supported by stakeholders, for instance during regulatory determinations. Revising investment decisions in these circumstances following a change in CECVs will reduce the credibility of our stakeholder engagement processes, and may not be in the long-term interests of customers. It is unclear in the AER's draft CECV methodology paper what would constitute as a 'material' change to assumptions in the ISP's step change scenario, and subsequently when updates to the CECVs would be triggered. We would appreciate if the AER were able to provide additional guidance on what it constitutes as 'material' to improve industry and stakeholder understanding of when updates to CECVs would be likely.	See sections 3.4 and 3.5.
6.3	Updates to values and methodology	SA Power Networks	As CECVs are to be a key input to distributors' cost benefit analyses and business cases, and the consumer / stakeholder engagement that they undertake on these, any changes, by way of annual updates and / or changes in methodology should be timed appropriately. In our view, material changes in methodology, such as changes in the scope of wholesale market benefits captured (e.g. the range of ESS) should be undertaken by the AER prior to the commencement of each round of AER Distribution Determinations. This is particularly noting the rapid rate of change in the DER market, regulatory developments, and the evolving scope of ESS in the NEM.	See section 3.5.2: We will consider the timing of future reviews to ensure that DNSPs have sufficient time to input values derived under the updated methodology in their regulatory proposals.
6.4	Updates to values and methodology	Ausgrid	In addition to these factors set out by the AER we consider that the CECV methodology should be subject to a review prior to the five-yearly review if: • a material or systematic error is identified in the estimation of CECVs; • the assumptions underpinning the estimation of CECVs are materially revised e.g. there is evidence of strategic behaviour not captured within existing modelling; or • the AEMO materially revises its integrated system plan scenarios. Some of the above factors may be capable of being incorporated through the revision of assumptions in the	See section 3.5.

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			context of annual CECV modelling. However, where changes are material, we recommend reviewing the underlying methodology.	
6.5	Updates to values and methodology	Energy Queensland	As the energy market evolves, we suggest further refinement of wholesale energy costs and increased requirements to provide essential system services may be required.	We agree that we should be cognisant of developments in essential system services markets, and have included a trigger to review the methodology if these become material.
7.1	DNSP model and characteristic days approach	Energy Queensland	Suggest the benefits of this model will need to be considered and that a simpler model would be beneficial. For this approach it would be more useful for the workbook to contain a single column of half hourly data such that the alleviation profile could be added in the adjacent column.	The DNSP model provides the half-hourly CECVs for each NEM region for all half hours in the analysis timeframe. The DNSP can simply multiply the amount of curtailment to be alleviated due to each of their projects by the CECV in each corresponding half hour to determine the total alleviation value of each project. However, the DNSP model also provides a simpler, alternative method that allows the DNSP to think about the amount of curtailment that will be alleviated on a limited number of characteristic days per year (rather than every half hour).
7.2	DNSP model and characteristic days approach	Energy Queensland	Analysis is still needed to determine the number of days in each characteristic day, and the alleviation of curtailment required for each type of day. However, this may reduce the analysis required when analysing a larger area. As such, Ergon Energy and Energex are supportive of an average value across the year, or by characteristic day. Provision of the aggregated PLEXOS would be helpful to understand how this approach compares to the self-selection outputs. As the characteristic days appear to be only dependent on demand and solar PV generation, we request clarity as to whether other types of generation have been considered. In our view, any approach should also consider night-time generation such as wind, battery or pumped hydro.	The characteristic days are primarily focused on those factors that are likely to lead to PV curtailment (e.g., PV output and operational demand). The DNSP model will provide the number of days of each characteristic day type that are forecast to occur in each NEM region in each year and the average CECV for each characteristic day type for each year for each NEM region. The DNSP will need to determine the amount of incremental export the alleviation project will enable on each characteristic day type in each year. The model will calculate the total present value of the alleviation. Using an average over a longer timeframe (for example an average annual CECV per region) would not be useful because (as noted in item 4.1) different alleviation projects may enable the same amount (MWh) of incremental export, but on very different half-hourly profiles and will therefore have different values in terms of upstream benefit. The model also contains all of the half hourly CECV values in each NEM region, which a DNSP could use to estimate the value that might be generated from alleviating other types of generation (e.g., 'night time

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				generation'). This approach could be used to assess the value of the incremental export provided by home energy storage and EVs in the future, however it is unlikely to apply to hydro and wind projects as they are typically individually negotiated connections and not subject to the Model Standing Offer (standardised residential connection agreement).
7.3	DNSP model and characteristic days approach	Energy Queensland	(Re: ranked characteristic days) It is our understanding the DNSP will need to determine the initial data, using half-hour data over the year, in order to determine the number of days where curtailment would apply, and the potential alleviation. We therefore suggest the benefit of this method over the characteristic day is unclear.	The DNSP will need, as a minimum, to estimate the amount of curtailment and the number of days on which that curtailment will occur. The DNSP model does not prescribe how DNSPs go about establishing these inputs. We would have expected that the above inputs would be required no matter what approach is adopted for estimating the value of reduced curtailment (i.e., it is fundamental to any evaluation of a project to increase DER hosting capacity). Beyond this, there is no requirement for a DNSP to use any particular option contained in the DNSP model – they are free to choose whichever option they choose, including whichever method they feel is easiest to use.
7.4	DNSP model and characteristic days approach	AusNet Services	Support DNSPs having the flexibility to choose the approach they consider most appropriate. The DNSP model should provide sufficient flexibility for a DNSP to either self-select or use characteristic days. If characteristic days are appropriately defined, this part of the model will be increasingly used by DNSPs (and there will, consequently, be no need to mandate its use). If DNSP choice is to be removed and characteristic days are to be the default approach, DNSPs should have the ability to rank days. We do not consider this ranking should be set by the AER and question the actual level of flexibility that will be realised where a DNSP needs to demonstrate the change 'is justifiable'. If the AER decides to rank days, the AER should publish the factors it will consider when making its decision on this issue. This will ensure a 'no surprise' environment and greater transparency – outcomes we expect the AER will be willing to embrace.	The intent of the DNSP model is to provide the DNSP with the choice of 3 methods for assessing the CECV benefit of their alleviation projects. No mandating of one or another approach is foreseen. Similarly, we will provide a ranking of the characteristic days for each jurisdiction along with how the rankings were assigned. Any particular DNSP may feel that a different ranking would be more appropriate for their service areas based on differences between the jurisdiction as a whole and conditions within their service area. However, the DNSP would be expected to provide the rationale for that alternative ranking.
7.5	DNSP model and	SA Power Networks	We wish to understand the desire of the AER to produce a 'DNSP model' for distributors to input their constraint /	DNSPs are free to input the published CECVs into their own

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	characteristic days approach		alleviation information into, as this appears to us to be impractical. We prefer that distributors have discretion to create their own 'integrated DNSP model', i.e. one model where distributors forecast network constraints and various investment options to alleviate export constraint, as this is likely to be more efficient noting that: • there are likely to be a high number of scenario runs to undertake during preparation of distributors' business cases, including continual model refinements, investment scenarios and sensitivities; • it would provide much greater insight for distributors, the AER, customers and other stakeholders on the performance / economics of different network investment options down to the individual asset level, i.e. we will be able to see the CECV value release for each investment; and • it will enable distributors to provide a faster turn-around of insights in response to queries from stakeholders during distributors' extensive consumer / stakeholder engagement programs.	models, provided that these are transparent and reviewable.
7.6	DNSP model and characteristic days approach	Ausgrid	We do not consider that applying the characteristic day approach should be mandatory. The proposed framework for ranking days may be less accurate than the self-selection approach, or indeed an alternative framework for aggregation. While we are supportive of the characteristic days approach being available as an aggregation option, alternative simpler forms of aggregation may provide for similar results and should be explored. Further information is required to determine whether ranking characteristic days provides a more robust or accurate option for aggregating CECVs relative to alternative aggregation approaches. While an appropriate framework, ranking characteristic days is dependent on the data held by Ausgrid and other DNSPs that would inform the ranking process. Accordingly, noting the limitations in the data held that would inform ranking characteristic days, we consider that DNSPs be allowed to re-rank characteristic days during the forthcoming 2024-29 regulatory period where information improves.	Using the characteristic day approach will not be mandatory. The DNSP model will provide the actual half-hourly CECVs for each half hour in each NEM region over the entire course of the analysis timeframe as part of the DNSP model. The DNSPs are free to use these directly in their assessment of the value that will be created by their hosting capacity projects. In addition, it should be noted that while the DNSP will include a set of ranked characteristic days for each region, the DNSP will be able to re-rank the days where they have reason to do so. The AER will expect the DNSP to provide a rationale for any such re-ordering.

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7.7	DNSP model and characteristic days approach	Consumer Challenge Panel	Concerned that the proposed flexibility in giving DNSPs three different approaches to modelling aggregate CECVs could reduce the overall transparency in the application of CECVs. Given that these approaches reflect a high degree of heterogeneity in the type of investments that use CECVs, it may be worth AER explicitly specifying which subgroup of investments designed to reduce export curtailment may use each of the three methodologies.	The three different methods in the DNSP model are provided to give the DNSP flexibility in how granularly they wish to define the alleviation profile of a given project. The motivation was to let the DNSP match the method to the amount of information/detail they feel able to provide about each alleviation project. They were not developed to be applied to different types of alleviation projects.
8.1	Other	Energy Queensland	Suggest a clearer comparison of each method, using the same proposal, would be helpful in determining the most appropriate methodology.	The choice of the three methods provided in the DNSP model is entirely up to the DNSP. The appropriateness of each will primarily be determined by the granularity of the information available to the DNSP regarding each alleviation project, and the degree to which the DNSP feels the characteristic days and characteristic day ranking within the model adequately represent conditions within their service area.
8.2	Other	Energy Queensland	Suggest a statement be included as to the connection size the AER is intending the CECV will be used for, e.g. large-scale registered generators. For method two, we would also appreciate additional clarity as to whether the average marginal wholesale energy cost provided is for a 24-hour period or daytime data, as this is not clear.	The CECVs can be applied to projects that are being considered for DER connected to the LV or HV portions of the distribution network. seek to It is possible that the bespoke nature of DER connecting at HV would mean that alleviation would be considered in the design and connection process. However, it might also be possible that the CECV could be used to assess the value of a different (presumably larger or dynamic) connection) that would allow a sufficient amount of incremental export with an aggregate upstream value that exceeds the cost of the connection. The CECVs provided for characteristic days is based on the average marginal wholesale energy cost for the specific hours associated with each characteristic day. These will essentially be midday hours when rooftop PV production can generally be assumed to be at its highest over the course of the day.

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