17 December 2021

Endeavour Energy

Dr Kris Funston
Executive General Manger, Network Regulation
Australian Energy Regulatory (AER)
GPO Box 520
Melbourne Vic 3001

Dear Dr Funston,

AER ISSUES PAPER: CUSTOMER EXPORT CURTAILMENT VALUES METHODOLOGY

Endeavour Energy welcomes the opportunity to provide this response to the AER's Issues Paper on the Customer export curtailment values (CECV) methodology.

With new requirements on DNSPs to provide customers with export services and restrictions on setting zero export limits, we expect DNSPs will increasingly direct investment toward managing the network for increases in customer-owned DER. Consequently, DNSPs will rely on the AER developing accurate CECVs estimates to guide efficient network planning and investment decisions for export services.

Interpreting CECVs

As a new concept, the issues paper focusses on how CECVs should be interpreted and estimated. In regard to interpreting the CECVs, we generally agree with the AER's initial positions. These include:

- CECVs should value the detriment to all customers from export curtailment (not just DER customers).
- Curtailment represents a scenario where a lower level of exports (base case) occurs relative to an expected level (investment case).
- DER penetration and curtailment scenarios will be specific to a DNSP and forecasts should be informed by a combination of AEMO and DNSP-provided assumptions.
- CECVs should be expressed in $/MWh.

Significantly, the issues paper suggests that the CECVs will capture wholesale market costs and benefits to customers as measured by changes in generator dispatch costs.[1] Whilst this is consistent with advice from the CSIRO/Cutler Merz Value of DER: Methodology study final report (VaDER report), we are concerned that this approach to estimating CECVs only considers the avoided marginal generator SRMC value stream which may lead to the wholesale market costs of curtailment in aggregate being understated.

For instance, whilst DNSPs efforts on estimating the cost of curtailment to date have largely focussed on estimating the avoided marginal costs of centralised generators displaced by DER, we expect avoided generation capacity investment will be increasingly important to consider as battery storage and other large-scale renewable generation increasingly become marginal. Consequently, the appropriateness of relying on avoided dispatch costs as the proxy for CECVs may diminish over time.

Furthermore, the proposed approach focuses too narrowly on wholesale market benefits at the expense other benefits that are valued by consumers but are not currently readily quantifiable or captured within generator cost information or market data. If the CECVs are to genuinely approximate the detriment to customers and the market from the curtailment of exports, it is important that they more broadly consider intangible customer benefits such as avoided greenhouse gas emissions, improved customer

[1] AER, Issues paper, Customer export curtailment value methodology, October 2021, p.12

empowerment and choice relating to self-generated exports and how communities would benefit from more exports as local energy systems become decentralised.

We understand that the CECVs cannot be applied to derive the total value associated with improving a network's DER hosting capacity, with DNSPs able to propose additional value streams (e.g. network sector benefits) as part of the value stack. As such, the wholesale market benefits estimated via the CECVs should represent a minimum or floor value to which DNSPs can add their estimates of other benefits independently of the CECV and incorporate these within their DER hosting investment assessments.

However, we remain particularly concerned there is limited scope for DNSPs in jurisdictions where there is no renewable energy target, carbon tax (or equivalent requirement) to incorporate environmental benefits in the value stack. With customers becoming increasingly engaged on climate change issues which is a factor in their decision to invest in DER, the value of environmental costs from curtailed exports could be undervalued. Unless consumer preferences are considered and captured in the value stack (separate to legislative obligations on generators which would otherwise be reflected in the wholesale market value streams), this could result in imbalanced and inconsistent cost-benefit analysis in business cases between DNSPs.

If not captured in the CECVs, it is important that DNSPs are confident the AER will be receptive to and accepting of additional value streams proposed by DNSPs for which the $/MWh estimates underpinning them are evidenced through engagement with customers and reflect the value they place on these benefits. For intangible benefits, this may require customers to be tested regarding their willingness to pay for these benefits, which could also be used to inform preferences around providing export service levels above the network's intrinsic hosting capacity.

Estimating CECV

We acknowledge that estimating CECVs is a complex task with several factors requiring consideration to ascertain the most appropriate methodology. In relation to the issues discussed in this section of the issues paper, we consider:

- Developing distinct CECVs for DER and non-DER customers would be difficult to estimate and will not likely be used to inform export tariffs.
- The AER should estimate CECVs by NEM region although DNSPs should have the flexibility to apply alternative values at a more granular level where accuracy is improved. Estimates should reflect the cost impact to customers in other regions which may result from the interconnected nature of the NEM.
- Temporal aggregation should reflect seasonal average 24-hour profiles at 5-minute granularity, potentially distinguishing between weekend and weekdays.

A key issue is whether the AER should pursue a shorthand or longhand (electricity market modelling) method for estimating CECVs recognising the final methodology should seek to balance simplicity with accuracy. It is generally accepted that market modelling provides more accurate estimates of wholesale market benefits as it is better able to capture generator behaviours and interrelationships within the electricity sector that will have a bearing on dispatch costs. Notably, this approach requires a long-term view of how the NEM will be configured (to capture the avoided generation capacity investment value stream) for which the AER would be well placed to forecast. It would therefore be appropriate for the AER to apply a longhand approach.

Nevertheless, we maintain that there is a place for DNSPs to depart from the AER's estimates and apply CECVs derived through a shorthand approach, noting the VaDER report recommended the longhand method be undertaken for investments over a certain threshold amount or will realise a threshold of DER capacity.[2] Where the cost and burden of engaging the longhand approach will materially erode the benefits, or where economic justification for the investment case is not sensitive to

[2] Koerner M, Graham P, Spak, B, Walton F, Kerin R (2020), 'Value of Distributed Energy Resources, Methodology Study: Final Report', CutlerMerz, CSIRO, Australia, p.52

benefits and costs revealed through detailed modelling, DNSPs should have the flexibility to apply the simpler shorthand approach.

With our regulatory proposal due to the AER in January 2023, we are currently in the process of developing our DER integration forecasts and business cases for the next regulatory period. We will therefore use CECV estimates developed by an independent, expert consultant to inform our preliminary business cases. Once the AER publishes draft CECV methodology and estimates (scheduled for early 2022) we will be able to contrast methodologies and form a clearer view on how CECVs should be derived and to revise and finalise our plans in advance of our January 2023 regulatory proposal.

Our responses to the questions in the issues paper are provided in Appendix A. If you have any queries or wish to discuss our submission further please contact James Hazelton, Lead Engineer, New Technology at Endeavour Energy at [redacted]

Yours sincerely

[redacted]

Colin Crisafulli
Head of Network Regulation

Appendix A: Response to the issues paper questions

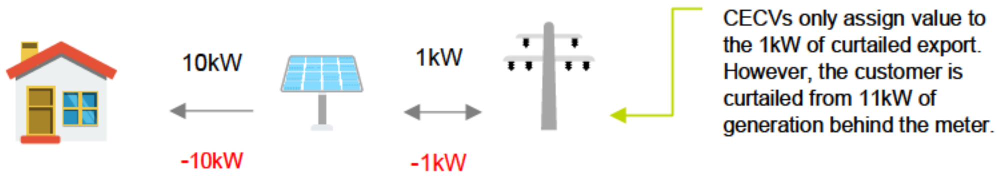
Question 1: Do you agree with our interpretation of export curtailment in the context of calculating CECVs?

The issues paper notes that DER export curtailment can occur when local network voltages exceed statutory limits[3]. While the vast majority of export curtailment may occur due to local voltage issues, it is a potentially limiting approach to define curtailment with respect to local voltage issues. Consistent with the aim of instilling a flexible approach as to when CECV could be applied, it would be preferable for any definition of curtailment to be agnostic as to the reasons for the curtailment.

The issues paper points to an alternative definition of curtailment, noting the definition of 'active power curtailment' as shedding or reducing of generated electrical power from distributed generation units, usually used in case of exceed the system hosting capacity[4]. This is preferable as an agnostic definition, leaving open the option of applying CECV where network investment supports reducing curtailment for other reasons (e.g., to address minimum operational load requirements).

Furthermore, the valuation of CECV relates specifically to the export from DER. We believe it is worthwhile considering the practical impacts of an 'export only' valuation of curtailment on PV systems given that, as per AS4777 volt-watt response modes, a PV system will curtail based on voltage irrespective if the PV system output is being self-consumed or exported into the network.

For example, a customer who is consuming 10 kW of power from their DER, and exporting 1 kW, would lose access to that 10 kW under that scenario. In the absence of a demand response, the consumer in this scenario would likely be required to consume 10 kW of load from the market, so the total market impact is 11 kW.



CECV valuation under the proposed approach looks only at the 1 kW impact – not the 11 kW total volt-watt based curtailment in this scenario. While this may be appropriate for CECV as currently envisaged, it will be important for any business case to ultimately consider what other benefits may result from the increase in hosting capacity – above the CECV. This could, for instance, be captured as part of the VCR benefit for a business case.

Question 2: Which value streams should be captured in the CECV?

The issues paper states that the CECVs will capture wholesale market costs and benefits to customers as measured by changes in generator dispatch costs[5]. To the extent that dispatch costs reflect a generator's variable operating costs and are more correlated to the avoided marginal generator short run marginal cost (SRMC) value stream, we are concerned that other wholesale market benefits - namely the avoided generator capacity investment and Essential System Services value streams – are not likely to be sufficiently accounted for. This follows CSIRO/Cutler Merz acknowledging that the electricity market is subject to long cycles of divergence from LRMC and that during periods of excess supply, generators are willing to dispatch at any price above their SRMC.[6]

It is likely to be increasingly important to incorporate avoided generation capacity investment in the future, as large scale renewables (and battery storage) are more frequently the marginal generator. Similarly, small-scale storage in aggregate will be capable of displacing conventional large-scale generators in providing cost effective reactive power management (i.e. ancillary voltage services). In

[3] AER, Issues Paper: Customer export curtailment value methodology, October 2021, p.13.
[4] Ibid, p.13
[5] Ibid, p.12
[6] Koerner M, Graham P, Spak, B, Walton F, Kerin R (2020), 'Value of Distr buted Energy Resources, Methodology Study: Final Report', CutlerMerz, CSIRO, Australia, p.116

these circumstances, having regard to avoided dispatch costs (i.e. SRMC) only will underestimate the wholesale market benefits of reducing export curtailment.

We note the AER propose to allow DNSPs to calculate generation capacity investment and essential system services benefits if they are necessary to justify an investment proposal.[7] In our view, these would be most accurately estimated under a long-hand approach, but the additional complexity and assumptions to be engaged upon and agreed may not be proportionate to the additional insights elicited.

We expect that the appropriateness of using avoided dispatch costs as the proxy for the CECV may diminish over time as battery storage and other large scale renewables increasingly become marginal. In this case, we expect that consideration of changes in investment costs will be increasingly important to support efficient DER integration investment.

Also, the issues paper is explicit in that CECVs will be different from VCRs as they intend to measure the detriment to customers and the market from a curtailment from exports. Like the VCR, the CECV ignores any potential synergies with other customers and community wide impacts from enabling more exports.

While these impacts may be minimal currently, given the emergence of community-based energy solutions, such impacts will increase. It is important that the CECV methodology is able to adapt to the changing nature of the energy sector and the shift from centralised to decentralised energy supply.

Question 3: Should CECVs reflect the detriment to all customers from the curtailment of DER exports, or particular types of customers?

Given that both export and non-export customers will share in the costs and benefits of increased DER, the CECVs should consider the detriment to all customers from the curtailment of DER exports. As noted by the AEMC, the values may need to capture not only the detriment of export curtailment to the customers using the export service, but also the potential detriment to all customers from lower levels of customer exports.[8] Importantly, capturing all customers in the CECVs will better guide efficient levels of network investment.

Question 4: How should CECVs be expressed?

As export curtailment is expressed in terms of MWh of energy curtailed from DER, the CECV is most appropriately expressed in a $/MWh value.

Question 5: Do you agree with our overall interpretation of CECV?

Notwithstanding our response to question 1, we broadly agree with the AER's interpretation of CECV and expect that they could be practicably applied in a similar manner to VCRs as an input into DER integration investment decisions.

In our view, the CECV in principle should capture the total avoided wholesale marginal costs incurred by the market of an increment reduction in the curtailment off solar PV exports. We reiterate our concerns that a focus on estimating dispatch costs (and the avoided marginal generator SRMC value stream) could result wholesale market costs of curtailment being understated, leading to a sub-optimal level of network investment in DER integration.

Question 6: Should there be a more explicit link between CECVs and export tariffs?

With the relationship between CECVs and two-way pricing being only an indirect one, there is no clear need for an explicit link for CECVs to inform export tariffs. In general terms, tariffs for export services will signal the LRMC of a DNSPs DER integration investment (as per the Pricing Principles) and will not be influenced by wholesale market factors captured by CECVs. Although, DNSPs should have the

[7] AER, Issues Paper: Customer export curtailment value methodology, October 2021, p.17
[8] AEMC, Rule determination: Access, pricing, and incentive arrangements for DER, 21 August 2021, p.63.

flexibility to share these investment costs between DER and non-DER customers in response to customer feedback and preferences on tariff structures.

Question 7: How could we estimate CECVs across different customer groups?

Given the CECV should estimate the impact of additional DER on the wholesale market, it should be treated the same according to each customer group as they all will consume from the same wholesale market in each state. The $/MWh cost of curtailment through the CECV would be spread equally across DER and non-DER customers in an electricity system view where wholesale price reductions are passed through to customers.

Also, it may not be appropriate for the AER to set CECVs for different customer groups as these groups and their characteristics will likely vary across DNSPs. An alternative approach would be for the AER to determine a CECV time profile, with DNSPs applying that profile to take account of the specific circumstances in each network (and the time profile of curtailment). We consider that customer groups are only relevant to the CECV insofar as the time profile of curtailment reflects their specific export profile (although presumably this might not vary significantly across a DNSP's network).

As per our response to question 6, we do not envisage a role for CECVs in setting export tariffs and believe deriving distinct CECVs for DER and non-DER customers would be difficult and of limited value. Export tariffs for DER customers would rather incorporate costs and considerations around the network hosting capacity in each area which can then incorporate considerations around non-DER versus DER customers.

Question 8: Should CECVs be estimated by NEM region?

CECVs are most appropriate to be estimated by NEM region given it reflects the wholesale market benefits which will be state-specific.

Notably, inclusion of MLF and DLF savings within the CECV will depend on the method by which CECV is calculated. If plant-specific SRMCs are used in the analysis of CECV, this can be MLF-adjusted to include the avoided losses through reduced dispatch of these centralised generators. This will need to assume that scheduled generators are the plants which have reduced dispatch, noting that reduction of load at a given point which is serviced by variable renewable energy (VRE) may then result in higher losses as the VRE will need to travel further in the network to reach the next load point. This could be completed independently and included within the CECV.

However, a simpler approach to SRMC which does not calculate on a plant-by-plant basis (e.g., a single SRMC over a fuel type) would not be able to estimate MLF changes in specific generators. Instead, this could be estimated based on the load MLF of the transmission connection point for the network in question. This can be used to adjust the avoided SRMC at that connection point. Given it will be dependent upon the location of the transmission connection point, this will not be able to be completed independently.

Question 9: Should CECVs for a particular NEM region reflect the impact of DER export curtailment that occurs in other NEM regions?

The interconnected nature of the NEM means that the benefits of DER (or costs of curtailment represented by CECV) in one region could have an impact in other regions. It is likely that behaviours at transmission interconnectors would need to be considered in modelling to determine the extent to which these benefits or costs (e.g. changes in wholesale prices) extend to consumers in other NEM states and territories. We discuss this in more detail in question 14.

Question 10: What is the appropriate temporal aggregation for estimating CECVs?

We agree that developing CECVs for each trading interval over the course of a year would present an onerous data challenge and it would be more pragmatic some form of aggregation in CECVs with the potential for networks to apply greater temporal granularity as analytical capabilities improve.

A 5-minute CECV curve for a day could be an appropriate initially as this then provides the flexibility for all DER to be valued rather than making assumptions about time-weighted averages which are likely to introduce significant challenges. For example, DER at peak should be valued much higher than DER at middle of day. A single DER value for a year would introduce many assumptions about how it is used.

We suggest an approach to aggregation which reflects seasonal average 24-hour profiles at 5-minute granularity with the possibility of distinguishing between weekend and weekdays to capture the material changes in the demand and SRMC curves. In this scenario, there would be eight daily CECV curves with 5-minute granularity.

Question 11: Should we also estimate CECVs into the future, or allow DNSPs to forecast changes in CECVs over time?

An annual forecast period is appropriate for the CECVs. Whilst it would be appropriate for the risk of inaccurately forecasting CECVs into the future and the costs of this risk lie with the same party, we consider DNSPs may not have the relevant expertise or oversight of the generation sector to accurately forecast changes in CECVs. The AER would be better placed to do this.

Alternatively, the AER could develop a formulaic approach to forecasting CECVs into the future and identify the data inputs and/or assumptions DNSPs should use.

Question 12: Do shorthand approaches provide sufficient forecasting ability or is electricity market modelling necessary for calculating CECVs?

In order to provide forecasting ability, a shorthand approach would need to make an assumption on the build-out of generation in the given state as this will impact the marginal generator and hence the avoided SRMC/wholesale price in the region. While a published projection of build-out could be assumed such as via AEMO ISP projections, this will inherently not include feedback loops through increasing DER output and hence be imperfect compared to electricity market modelling.

Using shorthand approaches to forecast would likely not provide the same level of accuracy when compared to more granular approaches such as market modelling. The complex interactions and changes in market behaviour across the NEM over time are unlikely to be accurately captured under a shorthand approach. Shorthand approaches are likely to be more suitable for a short-term view of CECV rather than a long-term forecast where interactions and feedback loops can be better integrated through market modelling. However, it is important to keep in mind that DER assets are relatively short life assets and accurately forecasting dispatch and investment costs beyond 12-15 years may be of limited value. Notably, sensitivities can be included to test potential boundaries under shorthand approaches – similar to work undertaken by HoustonKemp.[9]

The accuracy derived from a market modelling approach needs to be balanced against the additional expense and time involved as well as its tendency to provide stakeholders with less transparency than spreadsheet calculations. We maintain a shorthand approach would be more pragmatic where the investment is modest, urgent and/or where there is a clear and material net benefit to customers and the case for investment is not reliant on benefits revealed through detailed market modelling which would only serve to delay the investment and add to the overall cost.

We suggest DNSPs should have the flexibility to apply a shorthand and longhand approach, potentially with applicability limitations on each. For example a shorthand approach could be used where the

[9] AER, SA Power Networks – Determination 2020-25, 31 January 2019. Available here.

investment is NPV positive within 5 years, with a longhand approach used where the threshold is not met. This would be more proportionate and avoid costs and barriers associated with market modelling and analysis.

Question 13: How should generator bidding behaviour be modelled?

Generator bidding behaviour is included within electricity market models based on economic theory and price maximisation. For shorthand approaches, there is a trade-off between modelling exact bidding behaviour and future resilience of the approach, noting that it is likely to be impractical to model changes in bidding behaviour over time in a shorthand approach and hence a static estimate will need to be used. More sophisticated models of bidding behaviour are unlikely to be practical or transparent to implement for shorthand approaches.

For shorthand approaches, in practice, while historical bidding behaviour could be used to calibrate the model, over a long enough timeframe this is likely to become inaccurate as the market changes and there is an increase in zero cost renewable generation entering the system. This is likely to restrict the timeframe over which such bidding behaviour should be used. On the other hand, using a theoretical bidding price such as the SRMC is unlikely to reflect current bidding behaviour in the market, but is more defensible over the long-term if bidding behaviour is kept static. This would also provide much greater transparency to participants over the assumptions being used, noting that AEMO publishes SRMC for each generator in the NEM.

In order to provide a medium between the two approaches, a hybrid model of bidding behaviour could be used if bidding behaviour can be attributed to physical characteristics rather than specific strategies used by generators which may change over time. For example, while coal generators will be classified as having an average SRMC above zero, in practice there is a large amount of coal capacity which bids at the market floor. This can be linked directly to the fact that due to minimum load of coal plants, the SRMC of a certain portion of the coal plant is market floor (or lower in reality) while the residual SRMC of the coal plant is a measure of fuel and operating cost. Hence, a model of bidding behaviour based on SRMC could be adjusted to account for these market characteristics which are likely to persist in the long term.

Question 14: How should interconnector behaviour be modelled to determine regional CECVs?

A longhand electricity market model would include interconnector behaviour in the balance of supply and demand across the NEM and hence this behaviour would already be included. However, for a shorthand approach, inclusion of interconnector behaviour could add significant complexity into the approach as it would require the shorthand approach to be applied across all interconnected states (to calculate avoided SRMC due to changes in demand caused by interconnector flows). If the shorthand method is sufficiently simple (e.g., use of historical wholesale price as a proxy for SRMC of the marginal generator), this may be practical. However, other shorthand approaches such as modelling of bidding behaviour or marginal generator profiles would potentially create complexity in attempting to model the same behaviour on other states.

As a hybrid, interconnector impacts could be included through using the wholesale price in interconnected states weighted by the impact of PV generation on regional electricity imports/exports. This could then be added to a more complex shorthand calculation method for the state in which the CECV is being calculated.