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Dr Kris Funston

Executive General Manager, Network Regulation

Australian Energy Regulator

Submitted by email to: AERinquiry@aer.gov.au

21 December 2021

Dear Kris

AER Customer export curtailment value methodology, Issues Paper, October 2021

AGL Energy (**AGL**) welcomes the opportunity to respond to the Australian Energy Regulator's (**AER**) Customer export curtailment value methodology, Issues Paper, October 2021 (**Issues Paper**).

Strategic direction

AGL supports the AER's development of the Customer export curtailment value (**CECV**) methodology, that will inform a more robust approach to assessing distribution network service providers' (**DNSPs**) proposed expenditure as an input into network planning, investment, and incentive arrangements.

As we previously observed[1], the CECV methodology will support the accelerating uptake in DER and the scaling of business models such as orchestration. This is in line with the policy direction articulated by the Energy Security Board (**ESB**) in its Post-2025 Market Design. It will be critical that the AER's network expenditure assessment framework enables consumers being rewarded for their flexible demand and generation.[2]

Methodology

In developing curtailment scenarios as an input into CECVs, we would recommend the AER align its proposed curtailment scenarios with 5-minute market settlement. This will support modelling that more appropriately values the role of flexible generation sources such as DER and is consistent with current wholesale market dynamics and pricing. The level of aggregation of CECVs should in turn reflect individual DNSPs' proposed investment approaches.

We anticipate a range of complexities in the AER's proposed approach to forecasting and modelling wholesale market benefits and costs. These complexities will need to be carefully weighted to mitigate inaccuracies and/or overestimations that could otherwise result in inefficient DNSP expenditure, the cost of which would be borne by consumers.

[1] See AGL submission in response to AER's draft DER integration guidance note (2 September 2021), Available at https://www.agl.com.au/thehub/articles/2021/09/agl-responds-to-aers-draft-der-integration-expenditure-guidance-note.

[2] See Energy Security Board, Post-2025 Market Design Final advice to Energy Ministers Part A (27 July 2021), Available at https://esb-post2025-market-design.aemc.gov.au/32572/1629944958-post-2025-market-design-final-advice-to-energy-ministers-part-a.pdf.

We do not consider the AER should establish any direct or causal relationship between CECVs and export pricing. Any future export charges should be defined in terms of each network's intrinsic hosting capacity. Export pricing should also be driven by cost recovery with respect to provisioned capital and operational expenditure, as elaborated in DSNPs' approved regulatory reset proposals.

Complementary reforms

We also look forward to engaging with the AER in updating its broader Expenditure Forecast Assessment Guidelines (**EFA Guideline**), following the Australian Energy Market Commission's (**AEMC**) Rule determination on access, pricing and incentive arrangements for DER.[3] We do not consider that the EFA Guideline as it stands is fit for purpose to assess DER integration expenditure. The latest revision was in November 2013 and the EFA Guideline did not contemplate DER integration.

Given the broad range of potential consumer impacts associated with network businesses' varying approaches to DER integration, we consider greater regulatory oversight is required in the form of an AER Guideline to facilitate more consistent outcomes.

We consider a more holistic approach is required to ensure a coherent framework that effectively addresses DER integration considerations alongside traditional energy supply expenditure, given the interdependency between distributed energy and more transitional energy supply arrangements. This is particularly important given the broad range of complementary distribution network reforms currently underway, including network tariffs innovation and the introduction of two-way pricing, two-way markets, dynamic operating envelopes and connection agreements as well as technical standards, network interface and data sharing protocols.

We have carefully considered the questions raised in the AER's Issues Paper and elaborate our views in the **Attachment**.

Should you have any questions in relation to this submission, please contact Kurt Winter, Regulatory Strategy Manager, on 03 8633 7204 or KWinter@agl.com.au.

Yours sincerely

Elizabeth Molyneux

GM Policy and Markets Regulation

[3] See AEMC, Access, pricing and incentive arrangements for distributed energy resources, Rule determination (12 August 2021), Available at https://www.aemc.gov.au/sites/default/files/2021-08/Final%20determination%20-%20Access%2C%20pricing%20and%20incentive%20arrangements%20for%20DER.pdf.

ATTACHMENT

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

AGL agrees with the AER's interpretation of export curtailment in the context of calculating CECVs that entails the following:

- DNSPs must estimate the expected value of additional DER exports that will occur as a result of their proposed investments;
- CECVs will capture the wholesale market costs and benefits to customers, as measured by changes in generator dispatch costs;
- The AER need not identify instances of curtailment and estimate the impacts on specific customers, but rather assume that curtailment is a scenario where a lower level of DER export occurs relative to an expected level.
- Defining these scenarios (including setting the expected level) would be a key element of the CECV methodology and the AER would draw upon assumption published by the Australian Energy Market Operator (AEMO) as well as inputs from DNSPs about the level of DER exports on their distribution networks.
- In contrast to the value of customer reliability, DER delivers benefit to the electricity system via several services which are otherwise provided by direct – and largely incumbent – competitors. We agree that, to some extent, it is possible to measure the impact of DER by directly comparing its value against the value provided by existing technologies, such as centralised electricity generation. However, we note some complexity in this approach below in response to Question 12.

In developing curtailment scenarios as an input into CECVs, we would recommend the AER align its proposed curtailment scenarios with 5-minute market settlement, as this will support modelling that more appropriately values the role of flexible generation sources such as DER and is consistent with current wholesale market dynamics and pricing.

The level of aggregation of CECVs should in turn reflect individual DNSPs' proposed investment approaches. For example, if a DNSPs is proposing to procure services from competitive DER assets in Q1 only, then the CECV should be aggregated to reflect the monthly impact in order to support relevant industry investment and planning.

2. Which value streams should be captured in the CECV?

We note the AER's proposed DER value streams that could be captured in the CECV, as articulated in Table 2 of the Issues Paper.

We agree with the AER's view that the CECV methodology should primarily provide the methodology for calculating wholesale market benefits, as there is a greater potential to calculate these benefits independently and consistently between DNSPs. Nevertheless, we anticipate some complexity in forecasting and modelling marginal generator SRMC (fuel and maintenance costs) that will need to be carefully considered. We elaborate further below in response to Question 12.

We also agree that the other DER value streams elaborated in Table 2 should be permitted but in practice not all the value streams listed may be applicable and that DNSPs should be guided by consistent approaches to quantify these value streams, including:

- To quantify network sector benefits, DNSPs should either adopt network planning processes described in the AER's RIT-T and RIT-D guidelines (where there are project-specific impacts) or estimate average LRMC (where there are broad network impacts). Avoided transmission and distribution losses should be built into the calculation of wholesale market benefits.
- To quantify environmental benefits, renewable energy targets and/or a potential carbon price for generators (where there is a jurisdictional requirement) should be reflected in the calculation of wholesale market benefits and through avoided transmission and distribution losses.
- To quantify changes in DER investment, DNSPs should estimate changes in DER customer investment costs, excluding DER subsidies that customers receive.
- To quantify the benefits associated with these value streams for their proposed network investment but that in practice not all the value streams listed in Table 2 may be applicable.

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

We consider that CECVs should contemplate the detriment to all customers and separately to DER exporters, given that DER customers will experience different benefits because of their ability to engage with the energy market system through orchestration services.

4. How should CECVs be expressed?

We agree with the AER's proposed approach that CECV's could be expressed as $ per MWh of curtailed solar PV generation by reference to wholesale market costs.

5. Do you agree with our overall interpretation of CECV?

We support the AER's overall interpretation of CECVs, including that:

- The AER will use AEMO or DNSP provided assumptions to develop scenarios where more/less DER exports occur and estimate the benefits/costs to customers under these scenarios.
- The CECV methodology will capture the additional wholesale market costs due to DER export curtailment, as the AER can use market information to independently estimate these costs. However, DNSPs will be permitted to estimate other costs and benefits in their investment proposals, which may be specific to their proposed investments.
- Value represents the detriment to all customers from the curtailment of customer exports, or more generally the detriment to all customers from lower levels of customer exports. However, the AER should also calculate CECVs for DER customers to account for particular impacts to their investment.

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

We agree with the AER that there is not a direct or causal relationship between CECVs and export pricing because any future export charges will be defined in terms of each network's intrinsic hosting capacity. We do not consider that any direct or causal link should be established.

As we observed in response to the AER's Consultation Paper on Export tariff guidelines for distribution network export tariffs, export tariffs will predominantly or solely reflect the incremental cost of providing additional export capacity.[4] We consider that export pricing should be driven by cost recovery. Directly linking CECVs to export pricing risks reframing DNSPs' pricing approach as one of value-based pricing and positioning DNSPs with *de facto* market powers with respect to the value that can be realised by DER asset owners.

7. How could we estimate CECVs across different customer groups?

We consider that estimating CECVs across different customer groups could entail regional or nodal based analysis by reference to local DER export intensity.

8. Should CECVs be estimated by NEM region?

We agree that CECVs should be estimated by NEM region, as this would ensure a consistent approach with current NEM operations and the value of energy in each NEM region.

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

We support that CECVs for a particular NEM region reflect the impact of DER export curtailment that occurs in other NEM regions. However, we anticipate the impact of DER export curtailment that occurs in other NEM regions may already be reflected in wholesale forecasting and modelling of marginal generator SRMC (fuel and maintenance costs).

10. What is the appropriate temporal aggregation for estimating CECVs?

In developing curtailment scenarios as an input into CECVs, we would recommend the AER align its proposed curtailment scenarios with the 5-minute market settlement periods settlement, as this will support modelling that more appropriately values the role of flexible generation sources such as DER and is consistent with current wholesale market dynamics and pricing.

The level of aggregation of CECVs should in turn reflect individual DNSPs' proposed investment approaches. For example, if a DNSPs is proposing to procure services from competitive DER assets in Q1 only, then the CECV should be aggregated to reflect the monthly impact in order to support relevant industry investment and planning.

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

We also support that CECVs be forecasted into the future to support DNSPs forecasting CECVs for each year over the life of proposed investments. We agree with the AER that this could be forecast by reference to ASX future market and AEMC price trend reporting.

We would recommend that the forward period should be prescribed by reference to the ASX traded curve which is about three years plus a quarter. This would guard against potential inaccuracy.

[4] See AGL submission in response to AER Consultation Paper on Export tariff guidelines for distribution network export tariffs (4 November 2021), Available at https://www.agl.com.au/thehub/articles/2021/11/agl-responds-to-aer-consultation-on-export-pricing-guideline.

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

AGL supports the development of a balanced methodology between short-hand and long-hand approaches, provided all networks are required to apply a consistent methodology in their proposals to facilitate comparability. We appreciate the AER's observation that while short-hand methods may be inaccurate, long-hand methods may prove overly complex.

AGL's initial view is that in the short to medium term the short-hand approach would probably be adequate to calculate the CECV. In the longer term, a market modelling approach may be required as batteries and other storage becomes more prevalent. This is especially true as when curtailment increases, the marginal benefit calculation may no longer be appropriate.

There are some difficulties in the short-hand approach (which is understood to use the published price setter) in calculating a true marginal generation for these purposes, for example:

- Circumstances where the price setting generator is tied between generators, set by frequency control ancillary services (FCAS), set by interconnector (Basslink is common) or there is intervention pricing in place.
- Negative price events or times when the price is at zero where the price is being set by thermal generation assets (to make sure they stay online). In this circumstance it is not clear if this approach is still reasonable due to the divergence between actual market outcomes and a theoretical economic cost.

Clear guidance to address these issues may facilitate this approach to work in the short to medium term. In the longer term, it may be necessary to adopt a different modelling approach that more closely resembles long-hand electricity market modelling, to mitigate inaccuracies and/or overestimations that could otherwise result in inefficient DNSP expenditure, the cost of which would be borne by consumers.

13. How should generator bidding behaviour be modelled?

If the intent is to calculate the change in dispatch costs, then SRMC bidding with a market model is likely to be sufficient. Whilst there will be out of merit order dispatch, the uncertainty in bidding behaviour is likely to outweigh any benefit in using more complicated bidding strategies. It is also unclear if any of these strategies are adequate in the scenarios in which curtailment is likely to occur (i.e. high solar, low demand and low thermal coal powered generation level). Hedge and PPA contracting are likely to dominate behaviour.

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

Due to the regionalisation of the CECV but using a dispatch cost approach rather than spot price, the apportionment of value to each region is somewhat ambiguous (especially once loop flows begin with EnergyConnect). Some simple options might be to apportion using the previous year IR-TUOS values or using historical flow during curtailment periods. Arguably, it would be appropriate to proportion the benefit with interconnector adjusted losses when there is no separation between regions.