Clean Energy Council submission to the Australian Energy Market Commission Draft Determination: Access, pricing and incentive arrangements for DER

The Clean Energy Council (CEC) welcomes the opportunity to provide feedback on the Australian Energy Market Commission (AEMC) Draft Determination on access, pricing and incentive arrangements for distributed energy resources (DER).

The Clean Energy Council is the peak body for the clean energy industry in Australia. We represent and work with Australia's leading renewable energy and energy storage businesses, as well as rooftop solar installers, to further the development of clean energy in Australia. We are committed to accelerating the transformation of Australia’s energy system to one that is smarter and cleaner.

The proposal outlined in the AEMC’s Draft Determination is too open-ended. If implemented in its current form it would create significant uncertainty until the details of the export charges are approved in the next round of Tariff Structure Statements (TSSs), which will not be decided on for three to five years. In the meantime, solar designers and retailers would be unable to provide customers with a reliable estimate of the likely return on investment (ROI) of DER investments, and how the ROI might be affected by sizing of the solar array and energy storage system. The uncertainty could also dampen investment in virtual power plants (VPPs) until the new export charging tariffs are finalised. The best way to remove this uncertainty would be for the AEMC to clarify in its Final Determination that it will instruct the AER to ensure that export tariffs are not levied on customers who invested in DER prior to the finalisation of the details of the export tariffs. In other words, customers who invest prior to the commencement of the next TSS must not be subject to mandatory reassignment to an export tariff. This clarification would go a long way toward settling the apprehension the Draft Determination has caused to the solar industry and its prospective customers.

We welcome the AEMC’s recognition that it is appropriate to clarify that export services form part of the distribution service. We welcome the proposal to require the Australian Energy Regulator (AER) to develop guidance to assist distribution network service providers (DNSPs) in their expenditure proposals and provide clarity regarding assessment of export related expenditure. We also welcome the proposal to allow the AER to develop export service performance incentives.

Some CEC members have expressed concern regarding the potential for issues regarding competitive neutrality if DNSPs can recommend the export charges that would apply to assets that they (or their wholly-owned subsidiary) own and operate as well as the export charges applying to other assets that could compete with assets of the DNSP (or its wholly-owned subsidiary).

We are disappointed that the Draft Determination did not seriously address the issues regarding governance of the regulation of voltage management, which was highlighted in September 2020 in CEC’s submission to the AEMC Consultation Paper.

We are very disappointed that the Draft Determination declined to propose minimum expectations for distribution network service providers (DNSPs), such as a prohibition on the imposition of static zero export limitations. There should be a minimum level of export capacity available to all customers who are required to pay whenever they export electricity to the grid. If a minimum level of export services cannot be guaranteed, then the customer should not be required to pay for a second-rate service.

The proposed requirement on the AER to develop a methodology to calculate customer export curtailment values is incomplete and does not take account of the fact that production of electricity at the inverter is curtailed when network voltage is high, even when a DER system is exporting nothing due to local self-consumption. This means customers suffer losses with no gain to voltage management of the grid. This highlights the importance of regulation of voltage management on distribution networks.

The Draft Determination fails to outline whether the AEMC expects DER customers to fund remediation for legacy issues or if customers will only be charged for the marginal impact attributable to their exports. The CEC believes that if customers are charged for exports, they should only be required to pay for the marginal impact attributable to their exports. New customers should not be required to pay for remediation of legacy issues, such as the failure of some DNSPs to adjust transformers following the change from the 240V standard to the 230V standard.

We would be happy to discuss these issues in further detail with representatives of the AEMC.

1. The proposal is too open-ended

The proposal outlined in the AEMC's Draft Determination is too open-ended. If implemented in its current form it would create significant uncertainty until the details of the export charges are approved in the next round of Tariff Structure Statements (TSSs), which will not be decided on for three to five years. In the meantime, solar designers and retailers would be unable to provide customers with a reliable estimate of the likely return on investment (ROI) of DER investments, and how the ROI might be affected by sizing of the solar array and energy storage system. The uncertainty could also dampen investment in VPPs until the new export charging tariffs are finalised. The best way to remove this uncertainty would be for the AEMC to clarify in its Final Determination that it will instruct the AER to ensure that export tariffs are not levied on customers who invested in DER prior to the finalisation of the details of the export tariffs. In other words, customers who invest prior to the commencement of the next TSS must not be subject to mandatory reassignment to an export tariff[1]. This clarification would go a long way toward settling the apprehension the Draft Determination has caused to the solar industry and its prospective customers.

Delaying the key decisions on the details of the new export charging regime would create years of uncertainty for customers and the solar industry. This uncertainty will have an immediate impact. For example, the CEC's Approved Solar Retailer Code requires solar designers and retailers who provide estimates of a DER system's ROI to provide full disclosure of assumptions for purposes of transparency and to assist customers in their decisions regarding system sizing. If pricing parameters will not be set by regulators for several years, it will be problematic providing accurate and useful advice to customers. For example, the AEMC Draft Determination estimated that "customers could see their benefits reduced by around $100 per year" and, based on analysis of the electricity bills of thousands of Victorian customers, Bruce Mountain has predicted that, "A $100 export charge will all but extinguish the export income that the typical solar home in Victoria can expect when the revised feed-in rates apply soon".[2] It is possible that in future it would be in the interests of customers to have a zero export limiting device applied to their systems. There is insufficient information in the AEMC's Draft Determination to know.

The AEMC has proposed that the details of decisions on pricing, 'grandfathering' etc will be made through the Tariff Structure Statement process as part of DNSPs' regulatory determinations. Until those decisions are made, it is unclear what advice DER vendors and designers can provide to prospective customers on the likely return on investment for DER. The uncertainty this creates is a bad result for customers.

The AEMC seems to assume that customers will continue to want to export energy to the grid when there is a charge to do so. However, that could change as the value of energy during daylight hours continues to decrease. We recommend the AEMC undertake analysis that places the customer at the centre and considers the customer's likely response to changes in the value of exported energy, combined with anticipated decreases in the value of feed-in tariffs. There is a strong possibility that the proposed reforms will hasten moves toward maximising self-consumption, instead of exports. It would be helpful to understand this from a customer perspective. We urge the AEMC to commission independent behavioural research to understand how customers are likely to respond to these pricing changes.

To enable designers and retailers to continue providing advice to customers on the ROI for DER systems, it would be necessary for the AEMC to provide some upper and lower bounds for their pricing proposal. For example, the AEMC could require that the cost of export charges must not exceed the price paid for the electricity exported. Alternatively, the AEMC could specify upper bound on what it considers would be a reasonable export charge. Placing boundaries around what could happen with export charging will enable designers and retailers to provide ROI advice without the risk of inadvertently

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misleading customers. If no bounds are placed on the export charging proposal, there is a risk that designers and retailers feel compelled to stop providing ROI estimates to avoid the risk of misleading customers. That would be a bad result for customers.

2. Lack of clarity regarding who will pay export charges and/or connection costs

Under the Draft Determination, export charges can apply to all assets connected to the distribution network. This includes generators of all sizes (such as wind and solar farms and gas peaking plants), energy storage connected to the distribution network, VPPs and small rooftop solar systems owned by retail customers. There is no upper threshold. It is unclear whether large, embedded generators on the distribution network will be required to pay for connection costs as well as or instead of export charges and who will decide. These are all questions that must be clarified in the Final Determination to avoid dampening investment with policy uncertainty.

We understand that the AEMC has retained the option of applying export charges to all generators to provide ‘regulatory flexibility’. This ‘regulatory flexibility’ will create new uncertainty for investors in a market that is already fraught with regulatory uncertainty and rapidly changing rules. We urge the AEMC to commission independent research into the likely impact of this policy uncertainty on plans for investment in generation connected to distribution networks.

3. Competitive neutrality

It is unclear whether export charges would apply to energy storage systems on distribution networks that are owned and operated by DNSPs and whether this will be based on the proposals put forward by DNSPs in the TSS process. There is clear scope for competitive neutrality issues if DNSPs can set the export charges paid by the assets that they own as well as other assets that could compete with DNSP-owned assets.

Competitive neutrality issues will also result if wind and solar farms and gas peaking plants connected to distribution networks are required to pay export charges while competing wind and solar farms and gas peaking plants connected to transmission networks are not. This would result in a wealth transfer for distribution-connected assets to transmission-connected assets. It is unclear why there would be a benefit in tilting the playing field toward transmission-connected assets.

4. Governance of the regulation of voltage management

Voltage management on low voltage (LV) networks is a key component of the provision of ‘export services’ and ‘hosting capacity’. The Draft Determination is essentially proposing a national, pricing-based approach to voltage management which would be overlaid on a state and territory regulatory approach. It is unclear how the division of regulatory responsibilities would work in practice, with regulation of voltage management remaining at the level of state and territory regulators while the AEMC overlays a pricing-based approach for changes at the margin.

Governance of voltage management is currently highly fragmented and dysfunctional in the National Electricity Market (NEM). The only states that appear to have a functional regulatory framework for voltage management are Western Australia (which is outside the AEMC’s control) and Victoria (aided by the fact that it rolled our smart meters before the AEMC’s *Power of Choice* reforms).

By proposing regulation of export services through the National Electricity Rules (NER) while leaving the regulation of voltage management in the hands of state and territory governments risks perpetuating the dysfunctional governance arrangements.

A report commissioned by the Energy Security Board (ESB)[3] and undertaken by University of New South Wales[4], found that “even in the absence of solar PV, there is a significant level of high voltage across all DNSPs in all NEM states” and “many sites experience higher voltages during the night when solar PV is not operational”. The ESB notes that this “appears to point to a material level of technical non-compliance, but this may depend on how the data is viewed and how the respective standards are applied in each jurisdiction”.

Networks should first be required to meet their regulatory obligations regarding voltage management before a user-pays approach is introduced. Twenty years after the standards changed, some distribution networks have still not caught up from the shift from the old 240V standard to the current 230V.

This is a serious concern, and it is deeply disappointing that the Draft Determination dismissed this issue with the observation that, “The Commission considers that compliance with jurisdictional voltage standards is a matter for the relevant jurisdictional authorities” (p.78).

In the absence of initiative from the AEMC or the ESB we will seek leadership on regulation of voltage management from state and territory Energy Ministers and their officials.

5. No minimum export requirements for DNSPs

The rule change proposal put forward by the Australian Council for Social Services (ACOSS) and Total Environment Centre (TEC) included some constructive suggestions and the Draft Determination’s response to their suggestions is disappointing. We are especially disappointed that the AEMC does not support the proposal to prevent the imposition of static zero export limitation by DNSPs. There should be a minimum level of export capacity available to all customers who are required to pay whenever they export electricity to the grid. If a minimum level of export services cannot be guaranteed, then the customer should not be required to pay for a second-rate service.

We understand that the AEMC has expressed concern that preventing static zero export limitations could lead to ‘gold plating’ by DNSPs in fringe of grid areas with high solar penetration. The risk of this would be minimised by expediting reforms to enable DNSPs to utilise stand-alone power systems for regulated supply.

6. The Customer Export Curtailment proposal is incomplete

The proposed requirement on the AER to develop a methodology to calculate customer export curtailment values is incomplete. Electricity generation behind the meter is curtailed whenever network voltages exceed the power quality default set points, and the inverter is operating at full capacity.

AS/NZS 4777.2:2015 and its replacement, AS/NZS 4777.2:2020, use voltage to limit production of solar power at the inverter. This is a blunt instrument and results in loss of solar generation. Increases in grid voltage due to external influences will cause a PV inverter to ramp down electricity generation, even on a solar system that is exporting nothing due to local self-consumption. This means customers suffer losses, which should be considered in any estimation of the customer value of reduced curtailment. This highlights the importance of regulation of voltage management on distribution networks.

7. Payment for legacy remediation versus impacts at the margin

The Draft Determination fails to outline whether the AEMC expects DER customers to fund remediation for legacy issues (such as the failure of some DNSPs to adjust transformers following the change from the 240V standard to the 230V standard) or if customers will only be charged for the marginal impact attributable to the impact of their exports. Moreover, it is unclear how the policy makers or regulators

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would distinguish between legacy and marginal impacts particularly given that the AEMC has dismissed concerns regarding regulation of voltage management as the responsibility of jurisdictional regulators.

Clearly, DNSPs should be prevented from reallocating existing costs from consumption charges to export charges. They should also be prohibited from allocating residual costs to export charges.

The SA Power Networks proposal suggested that costs allocated to the export component of a tariff should only be the small portion of network revenues specifically associated with investments to enable exports – i.e. those costs that wouldn't have otherwise been required if the network was used only for downstream supply. This is an important point. Moreover, there should be verification of minimum legal compliance with regulations for voltage management before commencement of a 'user pays' approach to the changes on the margin caused by exports from DER.

8. Impact on customers' return on investment

Existing and future customers' return on their investments in DER will be affected by decisions on the following questions:

- How much will customers be charged when they export to the grid?
- Will the new export charging regime be optional or mandatory?
- Over what timeframe will the export charges be introduced?
- Will export charges be time-varying?
- Will export charges be location-specific?
- Will dynamically controlled DER be subject to a different export pricing regime?

If the AEMC clarifies that there will be no mandatory reassignment of customers to an export tariff and they will only apply to new connections (and additions and alterations) made after the export tariff is finalised through the TSS process, then the industry and its customers can continue to invest with reassurance regarding the likely impact of future regulatory decisions on their investment. However, if the above questions are left unanswered and if there is a possibility that export tariffs could be applied to customers who connect DER prior to the TSS approval, then it will be very difficult to estimate a system's likely ROI. This would be bad for customers and bad for investment in VPPs.

9. Impact on Virtual Power Plants

The impact of export charges on the viability of VPPs is unclear. For example, it is unclear whether aggregators and VPP operators will be able to optimise for energy market bids through an Australian Energy Market Operator (AEMO) platform while trying to incorporate input pricing signals from the individual DNSPs.

The uncertainty could dampen investment in VPPs. As noted above, the best way to remove this uncertainty would be for the AEMC to clarify in its Final Determination that it will instruct the AER to ensure that customers who invest in VPPs prior to the commencement of the next TSS will not be subject to mandatory reassignment to an export tariff.

10. Interaction with other reform proposals

It appears that there are several duplicative processes attempting to address the same problem and the interaction between those processes is unclear. For example, 'Dynamic Operating Envelopes' are intended to ensure that DER systems do not export when the distribution network is congested. The AEMC has failed to explain why customers should pay to remediate network congestion if they are prevented from exporting when the network is congested. If exports are limited to times when the network is not congested, what is the rationale for the proposed export charge?

11. Preparation for the Tariff Structure Statement process

The AEMC should consider whether changes are needed to ensure that the AER and representatives of industry and customers have the information they would need for to engage meaningfully in the next TSS. For example, will DNSPs or the AER publish the information needed to distinguish between expenditure to address legacy voltage management issues versus those caused at the margin by electricity exports? It is important to ensure that the decision about what customers pay for is not determined by the availability of information.

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The uncertainty could dampen investment in VPPs. As noted above, the best way to remove this uncertainty would be for the AEMC to clarify in its Final Determination that it will instruct the AER to ensure that customers who invest in VPPs prior to the commencement of the next TSS will not be subject to mandatory reassignment to an export tariff.

10. Interaction with other reform proposals

It appears that there are several duplicative processes attempting to address the same problem and the interaction between those processes is unclear. For example, 'Dynamic Operating Envelopes' are intended to ensure that DER systems do not export when the distribution network is congested. The AEMC has failed to explain why customers should pay to remediate network congestion if they are prevented from exporting when the network is congested. If exports are limited to times when the network is not congested, what is the rationale for the proposed export charge?

11. Preparation for the Tariff Structure Statement process

The AEMC should consider whether changes are needed to ensure that the AER and representatives of industry and customers have the information they would need for to engage meaningfully in the next TSS. For example, will DNSPs or the AER publish the information needed to distinguish between expenditure to address legacy voltage management issues versus those caused at the margin by electricity exports? It is important to ensure that the decision about what customers pay for is not determined by the availability of information.