# Response to AEMC Draft Determination on DER Export Pricing

Australian Energy Council | 27 May 2021

# DISCLAIMER

This report was commissioned by the Australian Energy Council (AEC) as part of its consideration of and response to the AEMC's *Access, pricing and incentive arrangements for distributed energy resources, Draft rule determination*, which was published on 25 March 2021.

The analysis and information provided in this report is derived in whole or in part from information provided by a range of parties other than Oakley Greenwood (OGW). OGW explicitly disclaims liability for any errors or omissions in that information, or any other aspect of the validity of that information. We also disclaim liability for the use of any information in this report by any party for any purpose other than the intended purpose.

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## This paper

This paper provides Oakley Greenwood's independent comments on the aspects of the AEMC's *Draft Rule Determination, Access, pricing and incentive arrangements for DER* (25 March 2021) that are related the pricing of DER export services. It does not comment on the other aspects of the Draft Rule Determination.

It was commissioned by the Australian Energy Council, but the opinions expressed are those of the authors, who have retained full control of the document throughout its preparation.

## Our comments

The key aspects of the Draft Rule Determination that are important in regard to the pricing of export services are:

- It would make explicit that providing for the export of energy is a distribution service, and therefore the current rules relating to distribution services apply to export services
- It allows distribution networks to charge customers that operate distributed energy resource (DER) systems when the use of those systems impose costs on the network, and to reward users when it reduces network costs or improves network operations or performance.

  Importantly, however, it does not require the distribution businesses to do so, nor does it prescribe the form in which they can do so. Those matters are subject to existing processes administered by the Australian Energy Regulator.

The underlying economic rationale for making this rule change is the role of pricing in allocative efficiency. In the context of export services, allocative efficiency is best served when the variable charges for those exports reflect the forward-looking marginal costs of providing that service[1]. This should help ensure that customers only export energy when and where the benefit to the consumer outweighs the cost to society of providing the export service. Allocative efficiency is a component of the National Energy Objective (NEO), which seeks to ensure that the operation of the electricity supply chain is in the long-term interests of consumers. All decisions made by the AEMC must be seen to be enhancing or at least conforming to the NEO.

Despite the pricing recommendations made in the Draft Determination conforming with economic principles and the NEO, several other objections have been raised. In our opinion, the key objections that have been raised are either immaterial, or lack merit, as summarised below.

- Objection 1: *The cost of accommodating additional DER export is small, and does not require anything other than routine work*.

  Early indications are the expenditures may not be small. For example, SAPN's most recent regulatory submission included $82m in capital expenditure over 5 years for increasing DER hosting capacity, which represented 5.1% of the company's total capex budget and was the single largest category of the company's augmentation expenditure – larger than capacity, reliability, or safety.

[1] There are several conditions which, where present, can override the value of sending cost-reflective marginal cost price signals. As discussed in the body of the report, we do not believe that any of those conditions exist with regard to the provision of a cost-reflective price signal for export services.

The work is not routine in that it primarily concerns over-voltage which has a cumulating effect as DER penetration continues to increase. This is not a need that the network businesses have experienced at a material level in the past.

In any case, the cost must be considered in light of the benefits that result from the expenditure, which is discussed in further detail below. It is also the case that these costs will grow as the penetration of DER grows, with the rate of growth being strongest where new DER cannot be orchestrated or controlled.

- Objection 2: *All customers and the environment will benefit from the lower prices that are created as a result of the exported energy*.

The need to manage voltage due to DER export does not occur every day, and even on days that it does occur, it will only be needed for certain daylight hours. As a result, any augmentation undertaken to reduce the occurrence of over-voltage conditions will only enable the export of DER in those hours.

It is the benefit of that incremental export that needs to be compared to the cost of the augmentation. The two most commonly noted benefits of DER export are reductions in wholesale electricity price and reductions in carbon emissions.

In this regard it is worth noting that additional DER export does not always displace fossil-fueled electricity or higher-priced sources of electricity.

For example, if the marginal generator (the price-setting generator) is wind or solar, everything else being equal, the incremental impact of increased DER export will be to back down a large-scale renewable generator. In such a case there will be no incremental reduction in carbon emissions. Examination of information about the operation of central plant in South Australia over the past three months reveals that solar or wind were the marginal plant in 21% of the trading intervals from 11:30AM to 3:00PM, which is when a significant amount of solar export occurs.

It is also the case that wholesale prices have been trending lower during the middle of the day due to the combined impact of the increasing amount of DER on the system (which lowers operational demand) and the increasing amounts of zero or near-zero marginal cost renewable electricity generation. According to AEMO, in the first quarter of CY 2021, the average wholesale spot price in South Australia between the hours of 10:00AM and 3:30PM was negative $12/MW. AEMO also noted that automated rebidding in response to negative prices comprised the single largest source of curtailment of wind and solar farms[2]. To the extent that DER export materially contributes to negative prices (which, in our opinion, it does), it may contribute to the self-curtailment of centralised wind and solar further reducing the additionality of DER exported electricity at those times.

Finally, we note that a negative price should indicate that the market is over-supplied with energy. Ideally, DER should receive this price signal as well, and at the very least, DER system owners should not be incentivised to export when the wholesale market is over supplied.

2 AEMO, Quarterly Energy Dynamics Q1 2021, pp 9, 13 and 28.

- Objection 3: *The impact on solar customers will be significant, putting at risk future investment in the industry*.

  This is a valid concern, but we do not think it is a likely outcome. This is because it is the AER that will be responsible for determining the suitable level of export pricing where proposed by any distribution business, and that determination will need to be undertaken in conformance with the existing rules regarding pricing in Chapter 6 of the NER, and in consideration of the distribution business' tariff structure statement.

  Given this, it is reasonable to expect that export prices will be based on the long-run marginal cost of providing the service, which will be calculated by reference to the distribution business' DER-related expenditure (the numerator in any LRMC calculation), and the incremental amount of energy that is forecast to be enabled by that expenditure (the denominator in any LRMC calculation). Importantly, the correct application of the existing network pricing rules mitigates the possibility that DER export charges will be expanded to recover sunk or fixed charges, which in turn will reduce the risk that the AEMC determination might disincentivise future investments that would have otherwise been efficient.

In sum, it is our view that the AEMC's draft determination is on very solid economic ground and will be of significant benefit in assisting in the economically efficient integration of DER with the overall electricity supply chain in a way that provides benefits to all consumers and importantly does not discriminate against DER owners.

# 1. Background and objective

## 1.1. Background

The AEMC has recently made a draft rule determination on access, pricing and incentive arrangements for distributed energy resources[3], that amongst other things, would create regulatory flexibility for new pricing options by removing the current prohibition on networks to charge for energy exported into the grid. If implemented, the rule change would mean that, in the future, distribution tariffs could include both charges for and payments (or credits) to customers.

For the purposes of this report, the two key aspects of the AEMC's draft rule determination that we have focused on are the AEMC's proposals around[4]:

> *Updating the regulatory framework to clarify that distribution services are two-way and include export services and that as such the current rules relating to distribution services apply to export services. This officially recognises energy export as a service to consumers that as such the current rules relating to distribution services apply to export services. This officially recognises energy export as a service to consumers…….*
>
> *Enabling distribution networks to offer two-way pricing for export services, allowing them options to reward owners of distributed energy resources for sending power to the grid when it is needed and charging them for sending power when it is busy. This is designed to reward customers for actions that better use the network or improve its operations, and allocate costs equitably and efficiently.*

Other pertinent aspects of the AEMC's draft rule determination are that:

- It is not mandating a specific pricing approach, rather, it is allows for solutions at the jurisdictional and network level that align with the current network pricing rules relating to distribution services (e.g., Rule 6.18), to be implemented; and
- Implementation is optional, and moreover, the AEMC's draft rule determination is not proposing that all customers with rooftop solar should be paying ongoing export charges. Rather, it is the AER, as the economic regulator, who will oversee revenue determinations and pricing proposals for each distribution network. Therefore, any decision to implement export pricing would be part of the AER's regulatory process (including ensuring that DER export pricing proposals align with the Rules).

The underlying driver for the AEMC's consideration of this issue is a technical one, as indicated by their statement that[5]:

> *"While there is no doubt that distributed energy resources provide many benefits to consumers and the energy system, without a change to the regulatory framework, consumers will face growing limitations to the amount of energy they can export. This is because distribution networks have a base level of hosting capacity for distributed energy resources. But most distribution networks were built when energy only flowed one way. Now, they are increasingly being used to export energy from customers and approaching the limit of their 'intrinsic hosting capacity'. As a result of these two-way flows, the ability of networks to transport and deliver electricity safely, securely and reliably is being challenged. These challenges raise medium- to long-term planning and investment issues.*

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3 AEMC, *Draft Rule Determination, Access, pricing and incentive arrangements for DER*, 25 March 2021.

4 Ibid., pp. i-ii.

5 Ibid., p. iii.

## 1.2. Objective

The Australian Energy Council (AEC) commissioned Oakley Greenwood (OGW) to prepare an independent response to the AEMC's *Draft Rule Determination, Access, pricing and incentive arrangements for DER* (25 March 2021).

The terms of the engagement agreed between the AEC and OGW was that OGW would:

- Develop our response based on fundamental principles of economic efficiency and the National Electricity Objective (NEO), and
- Provide independent views and have full control of the document including final editorial control of the document.

## 1.3. Caveats

For the avoidance doubt, the focus of this report is on the pricing-related aspects of the AEMC's draft rule determination, not issues related to access; the incentives that should be adopted to promote efficient invest in, operate and use export services; or the safeguards that are being proposed to ensure consumers and jurisdictional governments have a strong say in how distributed energy resources should be integrated into the energy system and priced.

# 2. The economic rationale for DER export pricing

Amongst all of the commentary on DER export pricing, one thing that sometimes gets overlooked is the underlying economic rationale for making a rule change in the first place. This in turn relates back to Section 7 of the National Electricity Law (NEL), which contains the National Electricity Objective (NEO), which the AEMC must adhere to when making all of its decisions. It states that:

> *The objective of this Law is to promote efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers of electricity with respect to–*
>
> *(a) price, quality, safety, reliability and security of supply of electricity; and*
>
> *(b) the reliability, safety and security of the national electricity system*

Underpinning the NEO is the concept of economic efficiency, which has three sub-components: productive, allocative and dynamic efficiency[6]. Allocative efficiency, which is related to the '*efficient….use of, electricity services*', requires that customers consume an efficient amount of electricity services (or as the AEMC has stated[7], the "*community's demand for energy services is met by the lowest cost combination of demand and supply side options*"). In the context of export services, which the AEMC has clarified is a distribution service as part of this rule change, this requires that variable charges for those export services reflect the forward-looking marginal costs of providing those services, so that customers only use that export service when and where the benefit to the consumer outweighs the cost to society of providing those (export) services.

In this context, the provision of a price signal that reflects the forward-looking costs of accommodating increased exports to the grid is valuable because it gives a point of reference against which the party causing the cost to be incurred (or its agent[8]) can assess whether there are more efficient alternatives (to exporting), which if implemented, would result in the community's overall demand for energy services being met by the lowest cost combination of demand and supply side options. For example, a cost-reflective variable price for export services would, everything else being equal, make:

- Self-consumption during times of export congestion[9] more economically attractive than export, which could potentially result in a range of economic options being adopted by customers including shifting the use of certain appliances such as pool pumps or dishwashers to those times,
- The use of existing on-site storages to store energy during those periods more economic, or
- Investments in new storage technologies to store energy during those periods more economic.

The goal is not to presuppose what the most efficient solution will be, but to provide the right price signals so that the market will arrange itself in a way that ensures the community's demand for energy services is met by the lowest cost combination of demand and supply side options.

As the AEMC states:

6 See AEMC, *Applying the energy market objectives*, 8 July 2019, page 12, for more detail on this.

7 Ibid.

8 The provision of a cost-reflective price signal can enlist innovation from intermediaries that can provide benefits to the electricity supply chain and the customer.

9 In the context of this report, 'export congestion' is a generic term that we are using to describe a situation whereby either network expenditure or the curtailment of PV export is required, due to the amount of energy being injected back into the grid.

> *There are good economic reasons to implement export pricing, both in the short-term to manage new investment related to distribution energy resources, and in the longer- term to take advantage of future market and technology developments. Pricing is a common tool used in regulated industries to send efficient signals for future expenditure and incentivise customers to best use existing infrastructure. It is about getting the most from the network we have and investing in the network over time to meet consumers' needs. Where significant new expenditure is required to maintain or improve export services, price signals can help to ensure it will be the result of customers making informed decisions about the costs that they impose on the network.*

Notwithstanding the above discussion, there are a number of valid economic reasons for not implementing a cost reflective marginal price signal in certain circumstances. These are if:

- Customers are unable to respond to that price signal by either changing their consumption or investment behaviour (i.e., their demand for that service is perfectly inelastic). If this is the case, there will be no economic benefit from sending the price signal. In our opinion, this is clearly not the case, as both existing and new PV owners are almost always going to have some feasible means of changing their behaviour on those occasions when a charge on solar export in in force. Examples of such behaviours include simply changing the time at which they use certain appliances, such as using their dishwasher or pool pump during the middle of day; or charging their battery or their EV at those times. Without a price signal, customers will not have the correct incentives at the margin when considering alternatives such as these[10];
- For whatever reason, the price signal is unable to be made cost reflective for a majority of customers, or at the majority of times (e.g., if it must be averaged), and the inefficient over-investment[11] that this leads to during periods where the price signal is artificially high (and vice versa) exceeds the inefficiency that is created by not sending the price signal in the first place. Again, in our opinion, if the network pricing rules are implemented correctly, this should not be case in this situation; or
- If the administrative costs (e.g., metering, billing) exceed the gross economic benefits generated from sending the cost-reflective price signal. In this case, the net economic benefit of introducing the price signal would be negative. We see no reason why this would be the case in the context of the DER export pricing, particularly given the metrology required to administer the pricing is already in place.

10 Although in some network areas, they face this indirectly by way of their export being curtailed. As the AEMC states, "*the reality is that rooftop solar owners are already paying a financial penalty from being constrained off the network at times, and this problem will become worse*".

11 Or loss of amenity, if the price signal results in a change in a customer's behaviour.

# 3. Response to a number of the common arguments against the adoption of DER Export Pricing

Critics of the AEMC's proposal have raised a number of issues, including:

1. That it is a very small cost and networks can easily accommodate injections without incurring significant expenditure
2. That all customers and the environment will benefit from the lower prices that are created as a result of the exported energy
3. That the impact on solar customers will be significant, putting at risk future investment in the industry

### It is a small cost and networks should be able to easily accommodate increased PV

A common argument against the adoption of DER export pricing is that the costs imposed by solar households are small and that if there is any issue (which some critics consider up for debate), it should be able to be easily accommodated by the network.

For example, one recent newspaper article that is critical of the AEMC's proposal states that[12]:

> *The costs imposed by solar households are small....This is seldom more than routine work...injections are typically much smaller than withdrawals and do not meaningfully increase network costs")*

Firstly, it is important to note that one of the key technical issues that is driving DER network integration costs is related to the effect injections are having on the network's ability to manage voltage issues; it is not just (or even primarily) related to whether or by how much injections are smaller than withdrawals (although reverse power flows are an ever increasing issue).

SAPN, in its revised regulatory proposal that it submitted to the AER, stated exactly this[13]:

> *DER management expenditure is the expenditure which seeks to manage these growing effects of higher penetration of DER on the network, in particular the effects of solar, and the cumulative impact it has on our ability to manage voltage within standards*

The AER reiterated this in its final decision when it stated[14]:

> *DER management expenditure is the expenditure which seeks to manage the growing effects of higher penetration of DER on the network, in particular the effects of solar PV and the impact on a distributor's ability to manage voltage within standards.*

As for whether the costs are small, in another report, the same author quotes the following figures[15]:

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12 https://theconversation.com/now-they-want-to-charge-households-for-exporting-solar-electricity-to-the-grid-itll-send-the-system-backwards-158055

13 SAPN, *Attachment 5 Capital expenditure, 2020-25 Revised Regulatory Proposal 20 December 2019*, page 44

14 AER, *Attachment 5: Capital expenditure | Final decision - SA Power Networks 2020-25*, page 40

15 B Mountain, *Analysis of the impact of proposals to charge solar homes to export electricity to the grid*, page 6

> *SA PowerNetworks – which has by far the most generous allowance for "distributed energy integration capital expenditure" ($16.4m capex per year for the next five years covering expenditure related to both big and small distributed energy) would establish a charge of around $16 per solar home per year in five years' time assuming all of the $82m allowance is spent. Powercor in Victoria, typical of other distributors in Victoria, will have an allowance for distributed energy integration capital expenditure of $32m that would establish a charge of around $6 per solar home per year in five years' time assuming all of the $32m is spent.*

We have no reason to doubt these figures. However, what we would say is that in and of itself, it is difficult to see how $82m over 5 years (in the case of SAPN[16]), could be considered "small", and at around 5.1% of SAPN's overall capex forecast of $1,595.8 million[17], it does not appear indicative of solutions that require "seldom more than routine work". Moreover, as the largest of SAPN's proposed 'Augex' expenditure categories[18] - larger than 'capacity', 'reliability', and 'safety' (amongst others) - its importance, at least to us, is self-evident.

Notwithstanding any of the above, it is important to relate the cost of the program to the actual benefit that is achieved from undertaking the program, which in turn relates back to how much additional energy is actually able to be exported as a result of that expenditure. If much of the proposed "distributed energy integration capital expenditure" is related to the management of voltage issues, and these voltage issues occur periodically (it is not a year-round issue[19]), and curtailment is only occurring during those periods, then:

- Not every single kWh exported from a PV system causes a voltage issue (which in turn should be reflected in how exports to the grid are priced); and
- Not every single kWh of PV that could be exported from a PV system is in fact facilitated as a result of the "distributed energy integration capital expenditure" – put another way, some will be enabled even without the expenditure (because of the existing network's inherent hosting capacity).

In short, any assessment as to whether the cost is small or not, must be considered in light of the additional energy that is exported as a result of that expenditure (the denominator). If the aforementioned conditions occur 60 days a year, and the (over) voltage issue is being managed by curtailing 15% of the PV that is on a feeder for 6 hours, this is the amount of additional energy facilitated by the expenditure in a year; not the full amount of energy exported by PV systems over that year.

### That all customers and the environment will always benefit from the lower costs and prices that are created as a result of the exported energy

There appears to be a strong feeling amongst many stakeholders that all customers and the environment will always benefit from the lower costs and prices that are created as a result of the exported energy.

16 SAPN is the network business that has up until now, been impacted the most by high PV penetration rates, hence it represents a good example of the level of cost that is likely to be incurred by other businesses as they too, face higher penetrations of PV, in the future.

17 AER, *Overview | Final decision – SA Power Networks distribution determination 2020-25*, page 15

18 SAPN, *Attachment 5 Capital expenditure, 2020-25 Revised Regulatory Proposal 20 December 2019*, page 44

19 It depends on a multitude of factors, including the level of underlying electrical load on the network and the amount of PV being exported at that time. Mild, sunny, cloudless days, combined with high PV penetration rates, are perfect conditions for (over) voltage issues to occur.

For example, in the same newspaper article that we referenced above which is critical of the AEMC's proposal, the author states that[20]:

> *"Distributed solar provides benefits for all consumers since it is close to where it is needed (and so reduces the need for transmission) and it displaces more expensive fossil fuel generation and so reduces wholesale prices".*

Intuitively, this makes sense. Energy generated from solar PV systems is renewable, it avoids the need to distribute energy through the transmission network and through higher voltages in the distribution network, and it 'in effect' makes more supply available to the market, lowering wholesale prices. The unsaid, but implied part of the above statement is that this should in turn flow through to lower retail prices for everyone.

However, the realities may be slightly different, depending on a number of different yet interrelated factors, including:

- Wholesale market conditions; and
- The marginal cost of hosting additional energy generated at a distributed level.

In relation to the former, it may not always be the case that more distributed energy displaces more expensive fossil fuel generation, hence leading to lower costs and better environmental outcomes. For example, if the marginal generator (the 'price setter') is wind or solar, everything else being equal, the incremental impact of increased distributed solar is that it is displacing a renewable centralised generator, not a fossil fuel generator. The following table summarises which type of generator has been the price setter in SA over the last 3 months.

Table 1: SA Price Setter Information

| Fuel Type | Percentage of all intervals in which it is the price setter | Percentage of the intervals from 11.30am to 3pm in which it is the price setter |
|---|---|---|
| Solar and wind | 7.61% | 21% |
| Hydro | 23.63% | 19% |
| Black Coal | 30.88% | 31% |
| Brown Coal | 14.08% | 15% |
| Gas | 20.49% | 9% |
| Battery | 2.65% | 5% |
| Other | 0.7% | 0.2% |
| **TOTAL** | **100.0%** | **100%** |

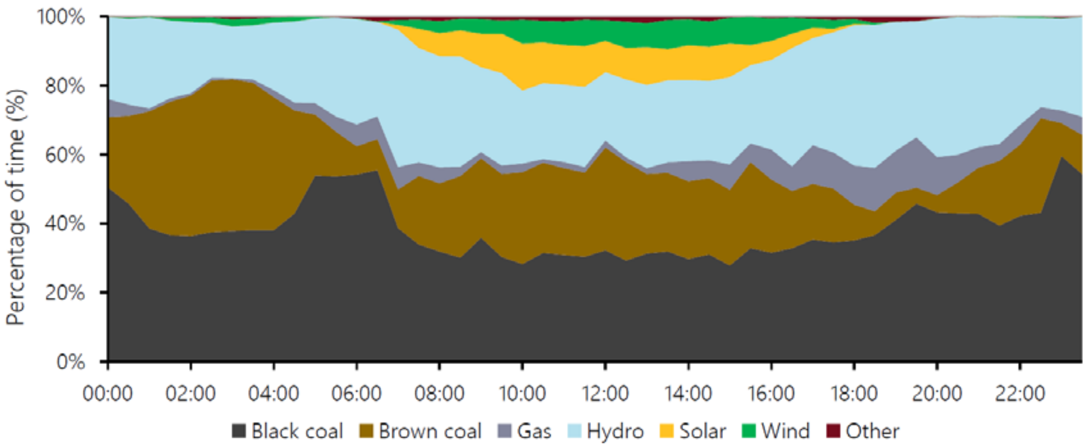
Source: OGW analysis, of wholesale market information derived from NEO database.

During the periods when distributed solar is predominately generating (early to mid-afternoon), which in turn is when any export tariff would most likely be levied, either solar or wind was the marginal generator 21% of the time in SA. During these times, the additional export of electricity from rooftop PV or other behind the meter DER will result in no incremental reduction in emissions.

20 https://theconversation.com/now-they-want-to-charge-households-for-exporting-solar-electricity-to-the-grid-itll-send-the-system-backwards-158055

The following figure, from AEMO's most recent quarterly report, indicates a similar outcome for Victoria.

Figure 1: Victoria's price-setting by fuel type and time of day - Q1 2021



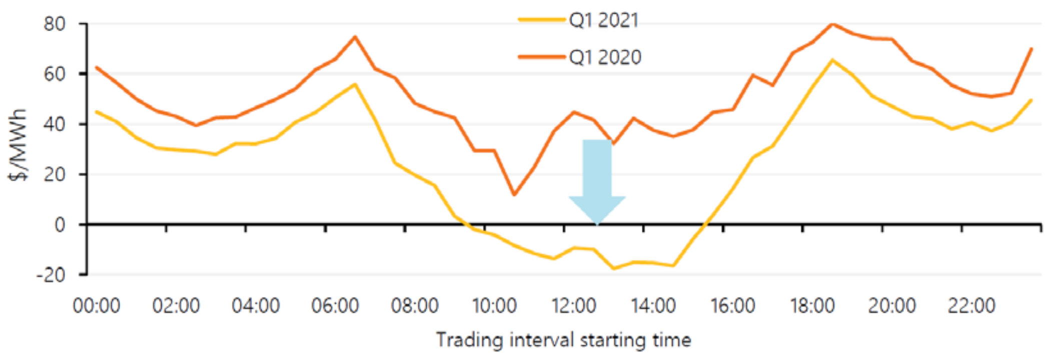

Source: AEMO 2021 | Quarterly Energy Dynamics Q1 2021, page 14

Also, during the middle of the day, when distributed solar is predominately generating, the National Electricity Market (NEM) has been experiencing an ever increasing frequency (and levels) of negative prices. A negative price is the market signalling that there is in effect an excess of supply from generators, relative to the grid-facing demand for electricity from energy users. This is not an isolated issue, as AEMO reports in its Quarterly Report[21]:

> *"Negative spot prices continued to occur at very high levels in South Australia (16.8% of the time), and Victoria (10.3%). In South Australia, the average spot price during peak solar production (between 1000 hrs and 1530 hrs) was negative $12/MWh"*

This is highlighted further in the following figure.

Figure 2: South Australian average underlying electricity price12 by time of day - Q1 2021 and Q1 2020

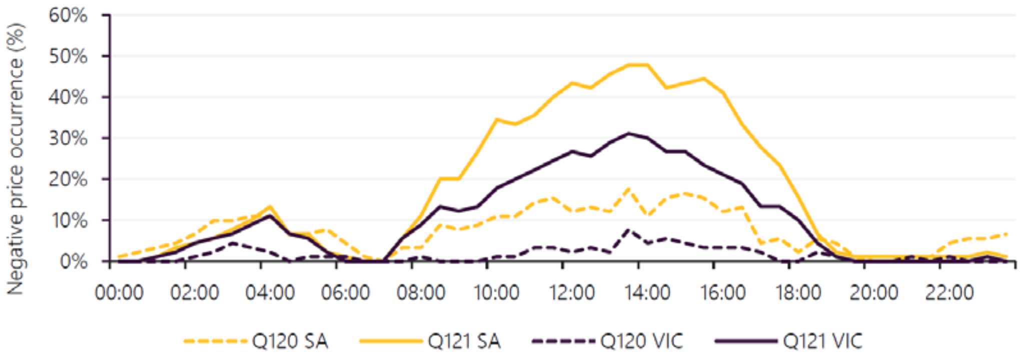



Source: AEMO 2021 | Quarterly Energy Dynamics Q1 2021, page 9

21 AEMO 2021 | Quarterly Energy Dynamics Q1 2021, page 3

Whilst the above quote indicates that negative prices have occurred in South Australia 16.8% of the time, AEMO's data indicates that they occurred significantly more frequently during the middle of the day, with around 45% of all half hour periods between midday and 3.30pm exhibiting a negative price.

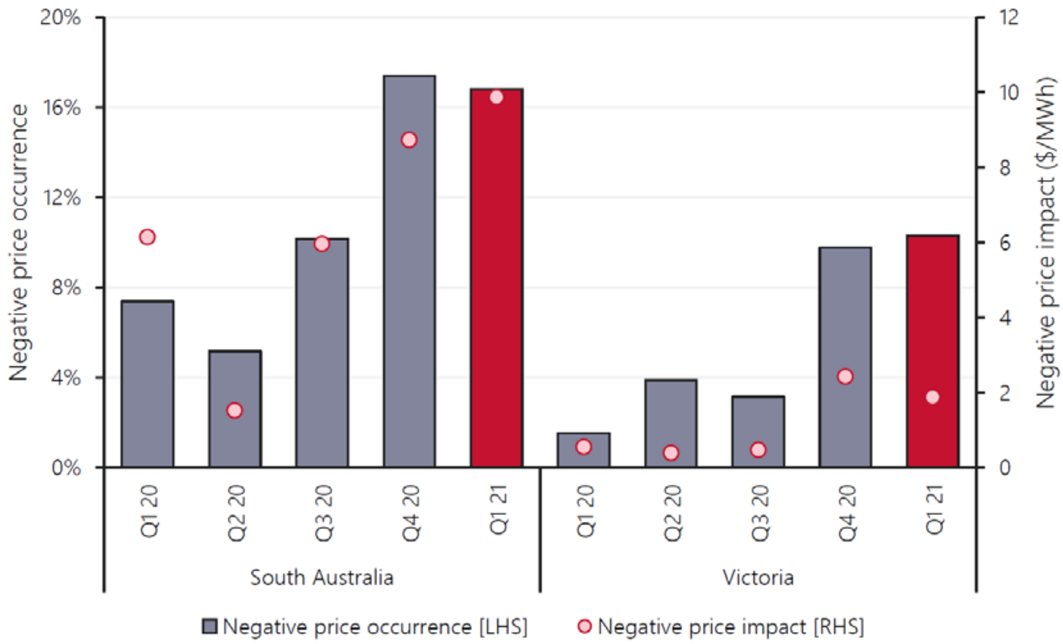
Figure 3: South Australia and Victoria Q1 negative price percentage occurrence by time of day – Q1 2021 versus Q1 2020




Source: AEMO 2021 | Quarterly Energy Dynamics Q1 2021, page 13

The figure below highlights the trend in negative prices.

Figure 4: Quarterly negative price percentage occurrence – Q1 2020 to Q1 2021




Source: AEMO 2021 | Quarterly Energy Dynamics Q1 2021, page 12

Importantly, AEMO notes that[22]:

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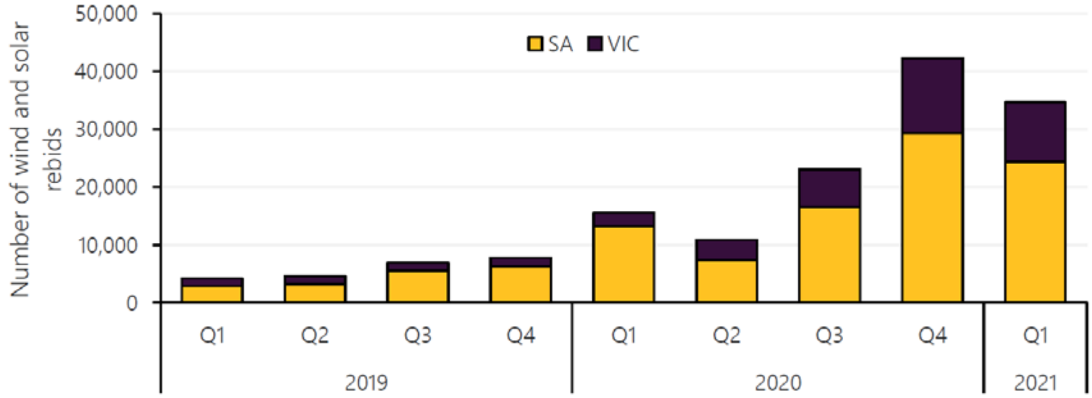
22 AEMO 2021 | Quarterly Energy Dynamics Q1 2021, page 13

> *"High levels of negative spot prices during the last two quarters have led to increasing responsiveness from wind and solar farms as they re-bid capacity to higher price bands to reduce the risk of being dispatched at negative prices. The combination of increasing occurrence of negative spot prices, as well as the deployment of automated bidding software during 2020, led to a substantial increase in re-bids. In Q1 2019, South Australian and Victorian wind and solar farms re-bid 4,258 times, increasing to 34,659 re-bids in Q1 2021 (+713%, Figure 15)."*

AEMO's Figure 15 is reproduced below.

Figure 5: South Australian and Victorian wind and solar farm number of re-bids by quarter




Source: AEMO 2021, *Quarterly Energy Dynamics Q1 2021*, page 13

AEMO go on to say that[23]:

> *"Economic curtailment - with high occurrence of negative spot prices in South Australia and Victoria, self-curtailment of wind and solar farms in response to market signals became the largest source of VRE curtailment. Economic curtailment accounted for 58% of total curtailment, with the highest levels of economic curtailment occurring at Tailem Bend Solar Farm (7 MW, or 27% of available output), Murra Wurra Wind Farm (7 MW), and Lincoln Gap Wind Farm (4 MW)."*

Much of this is driven by automated bidding systems, which enable participates to participate in the market more actively and respond more dynamically to the NEM's price signals. AEMO estimates that around one-third of South Australian and Queensland VRE capacity has installed automated bidding software, with a slightly smaller amount (around 20%) in Victoria.

In summary, while the export of renewably generated electricity from rooftop PV systems is good for the environment, that export may not always lead to incremental carbon reductions. In cases where rooftop export backs down central solar or wind facilities, there will be no incremental reduction in carbon emissions. In cases where rooftop export is materially contributing to negative prices (which, in our opinion, it is), rooftop PV may in effect be leading to the backing down of centralised wind and solar (via economic curtailment). This has consequential impacts on the underlying economics of centralised solar.

Finally, it seems incongruous to think that as a community, we would spend money to facilitate more energy being exported back into the system (particularly when it is displacing centralised renewables a not immaterial portion of the time), if negative (or very low) prices are expected to be a more consistent feature throughout the middle of the day (particularly when conditions are likely to correlate with when (over) voltage conditions are likely to occur in portions of the distribution network).

23 Ibid, page 28

A negative price is the market signalling that there is in effect an excess of supply from generators, relative to the grid-facing demand for electricity from energy users. Presumably, the AEMC's proposal[24] requiring the AER to regularly calculate the customer export curtailment values (CECV), which will be used to guide the network investment, planning and regulatory decisions for export services, and which, the AEMC states, “could be used to assess whether proposed steps to reduce export curtailment (such as increasing DER hosting capacity) can be economically justified”, will pick up on these market dynamics. Everything else being equal, this will make the probability of such investment being approved low. In this context, an export price signal, which allows the market to reveal the efficient level of demand for export services, may in fact assist PV customers.

### Impact on solar customers will be significant, putting at risk future investment in the industry

It is quite understandable that the solar industry, and its advocates, are concerned about the impact that any export price signal could have on their industry, and their individual financial situation.

There has also been a range of figures provided by the AEMC, advocates, the rule change proponents and others in relation to the impact that the rule change might have on PV owners' financial outcomes. One of the reports that has done this is by B Mountain (‘Analysis of the impact of proposals to charge solar homes to export electricity to the grid’). In it, the author states[25]:

> *In the AEMC’s assessment of the impact of its Draft Decision, the AEMC suggests that “networks” had told the AEMC that injection charges to recover distributed asset integration expenditure could range between $10 and $100 per year.*

He further states that[26]:

> *The bottom end of this range might be suggested to be consistent with network injection charges that seek to recover, from solar homes, the network expenditure associated with their integration into the grid*
>
> *In other words, an annual charge around the bottom end of what the distributors told the AEMC ($10-$100 per year) might be plausible as an annual charge to solar homes to recover distributed energy integration expenditure.*

He goes on to state that:

> *The AEMC also presents an analysis of a case study of a 5 kW solar home in Sydney that it says is charged $100 per year, the top end of the range of injection charges that distributors told the AEMC would be appropriate to compensate distributed energy integration expenditure.*

He goes on to state that[27]:

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24 The AEMC has introduced a new requirement on the AER under NER rule 8.13 to develop a methodology for and to regularly calculate customer export curtailment values (CECV). The Commission states that it "*considers these values are more likely to contribute to achieving the NEO than a measure for the value customers place on export service reliability because customer export curtailment values would better reflect the benefits to customers from exporting customers being able to access greater levels of export capacity. This is consistent with assessment criteria on the efficient provision of electricity services and regulatory burden for the parties involved*"

25 B Mountain, Analysis of the impact of proposals to charge solar homes to export electricity to the grid, page 6

26 Ibid

27 Ibid, page 12

*Our analysis suggests that the AEMC has made an error which means it has understated the network injection price that is consistent with its proposals by a factor of at least two. Accordingly we suggest that if a network usage is adopted along the lines that the AEMC suggests, it is likely to have a large (negative) impact on existing solar homes and is likely to significantly retard future rooftop solar installation by households.*

Whilst on one hand, the author states that the "*AEMC's proposal does not place any constraint on distributors on how they might wish to determine the injection charges that the AEMC's Draft Decision enables*", the author rightly notes that a main counter-argument to his contention that the AEMC's modelled prices would have a significant impact on PV owners, is that[28]:

*"it really does not matter whatever the AEMC suggests should be the network injection price since these will be established by distributors, and subject to some level of oversight by the Australian Energy Regulator".*

However, he then dismisses this by saying that[29]:

*"the rules do not bind distributors to only cover incremental costs in these charges" and*

*"distributors can be expected to set network usage charges that are consistent with the AEMC's intention" and*

*"the AEMC's proposal therefore plays an important role in anchoring distributor proposals and in setting expectations of what should be expected from the AEMC's Draft Decision".*

Firstly, it is our understanding that the suitable level of export pricing will be determined through the existing Chapter 6 pricing rules and tariff structure statement process, which is examined by the AER during the distribution revenue determination process. So it is correct that there is AER oversight, that is, it is the AER, not the AEMC that enforces the final rule. Any inference suggesting that the AEMC's published figures hold any specific relevance, beyond the purposes for which they are presented in their draft rule determination, is misaligned with the Rules and the overarching governance arrangements.

Secondly, whilst we agree that the rules may not specifically "*bind distributors to only cover incremental costs in these charges*", as the author has stated, it is important to note that they do provide a significant amount of guidance to the AER on this issue. Therefore, it is not, as is suggested, that the AEMC's proposal "*does not place any constraint on distributors on how they might wish to determine the injection charges that the AEMC's Draft Decision enables*"; rather, it is the case that these constraints are already contained within the Rules.

In particular, whilst each tariff must be based on the long run marginal cost of providing the service (which goes to the recovery of incremental DER integration costs), the Rules also require that for each tariff class, the revenue expected to be recovered must lie on or between:

- an upper bound representing the stand alone cost of serving the retail customers who belong to that class; and
- a lower bound representing the avoidable cost of not serving those retail customers.

Given that the AER's role is to implement measures that operationalise and enforce the intent of the rules, it should be expected that:

28 Ibid

29 Ibid

- Variable export price signals will have to be based on a distribution business' approved DER-related expenditure (the numerator in any LRMC calculation), and the incremental amount of energy that it forecasts will be facilitated as a result of that expenditure (the denominator in any LRMC calculation). Importantly, the denominator will need to align with the charging parameters that that business is adopting (i.e., they must be consistent)
- Any attempt to explicitly recover sunk or fixed costs from export charges, could:
  - Not be implemented via increasing the variable export charge (as this would lead to variable price deviating from the LRMC of supply, which is contrary to the rules); and
  - Almost certainly not be done via the adoption of a fixed export charge, as it is likely to lead to (inefficient) changes in PV customers' future consumption or investment decisions[30] (and given there are other, less distortionary means of recovering the cost of these sunk investments, these would be preferable)[31]

Notwithstanding any of the above, our previous analysis indicates that based on the currently revealed information (regarding DER integration costs), the impact on PV exporting customers is in the order of $15/annum $20/annum. The final figure would, however, be dependent on the size of the system as compared to the customer's load. Consistent with our statements above, and for the avoidance of doubt, this figure assumes that this charge does not recover any sunk investments. For a customer in NSW with a 5kW PV system, this equates to in the order of 2% of the annual financial benefit that the owner of that system would receive in the form of feed-in tariff income and retail bill reductions from self-consumption of PV-generated electricity. It should also be recalled that some of the customer's export may generate additional revenue relative to what it currently receives, from the services that it provides to the distribution business.

30 Whether it be in a PV system (including its sizing), a battery system or any other type of DER device

31 Via fixed charges at a tariff class level that do not breach the stand alone or avoidable cost test set out in the Rules.