Overcoming the limitations of variable renewable production subsidies as a means of decarbonising electricity markets

The limitations of production subsidies for variable renewable energy (VRE) plant as a means of decarbonising electricity markets are well known. Despite this, production subsidies for VRE plant are the most prevalent form of policy intervention in Australia. In the absence of cost-effective storage, production subsidies for VRE plant can create incentives to produce electricity at times the system may not need it, thereby severing the link between the spot market and financial incentives to generate. Such production subsidies can also reduce the incentive for new VRE plant to participate in 'firm' forward derivative markets. In this paper, we examine two adjustments that could be made to production subsidies for VRE plant that would correct for these unintended consequences. Firstly, the quantum of the subsidy could be a function of the wholesale electricity price, electricity demand or emissions; and secondly, new generators would be ineligible to receive production subsidies without demonstrating that they are facilitating the supply of financial derivative contracts. The effect of both adjustments would be to increase the incentive of VRE plant to demand-follow; that is, make its output 'firmer'.

Keywords: electricity market; production subsidy; variable renewable energy
JEL Codes: D04, D47, Q40, Q41, Q48

1. Introduction

Australia's National Electricity Market (NEM) is a gross pool with a uniform price clearing mechanism. In the spot market, generators are paid for their energy production but not paid for the capacity they make available. Pricing outcomes tend to trend towards short-run marginal cost (SRMC) when there is surplus capacity available. When capacity is scarce relative to demand, prices often rise well above average total cost. The NEM is based upon the principle that over the business cycle, the long-run marginal cost (LRMC) of an 'optimal' level of investment will be recovered (see Nelson et al., 2018).

The NEM allows for significant pricing volatility to both facilitate the most efficient dispatch of existing resources in the system, and to incentivise new entry. The wholesale spot price can vary from negative $1,000 per megawatt hour (MWh) to $15,000 per MWh.[1] The management of the associated significant price risk in such a volatile market is achieved through the use of financial derivative products entered into by retailers and generators. The use of wholesale hedging contracts provides greater certainty of generator revenue streams allowing them to obtain finance to operate. New investment in power generation is dependent upon these types of contracts being available.

Derivative contracts are effectively an agreement to pay the difference between the price specified in the contract and the spot price. When spot prices are high, generators pay the difference between the contract price and the spot price. Conversely, when spot prices are low, retailers pay the difference to the generator. Generators are incentivised to make sure they are available at times of high prices due to the significant financial penalties they implicitly face if they cannot generate because of these contractual arrangements. The spot and contract markets effectively work together to deliver the required amount of power on a day-to-day basis and also over the longer term.

Expectations of future spot prices are effectively a forecast of whether the market requires new investment. If a shortfall in capacity is expected, contract prices are likely to rise. How much generation needs to be available, where it needs to be located and the ideal type of generation are signalled through the contract market. To be able to participate in the spot and contract markets, generators are generally required to choose when to offer their supply via the prices bid into the spot market. Given variable renewable energy (VRE) generators, chiefly wind and solar PV, cannot choose when to operate as they have no fuel inventory (i.e. they produce when it is sunny or windy); they are dispatched as long as the price is greater than their opportunity cost of operation. In turn, this opportunity cost often represents the negative value of the production subsidy VRE generators receive, as these generators have minimal short-run marginal costs (Nelson et al, 2015).

These basic interactions between the wholesale spot and contract markets served the NEM well from its inception until around 2010. As Simshauser & Tiernan (2018) and Rai & Nelson (2019) note, instead of utilising a technology-neutral subsidy (such as an emissions-intensity scheme) or tax to decarbonise the NEM, policy makers adopted a range of renewables-specific production subsidies such as Premium Feed-in Tariffs (PFiTs), renewable energy certificate trading schemes, and upfront capital subsidies. Furthermore, as Rai & Nunn (2020) note, VRE plant have been the cheapest means of complying with these renewables-specific mechanisms. That is, renewables-specific production subsidies have become de-facto *variable* renewable energy subsidies.

The use of VRE production subsidies has limited the effective functioning of an energy only, gross pool like the NEM in two ways. Firstly, production subsidies for non-dispatchable VRE plant have broken the link between the spot market and the physical needs of the system, accentuating the 'merit-order' effect and leading to an enhanced 'boom-bust' scenario of wholesale electricity prices (see Nelson et al, 2018). Secondly, the emergence of long-dated Power Purchase Agreements (PPAs), developed by participants as a tool for compliance with production subsidy policies, has acted to reduce liquidity for traditional 'firm' hedge contracts, especially upon the VRE-induced exit of thermal plant (typical suppliers of 'firm' hedge contracts).[2] This is particularly relevant for government issued PPA style contracts that effectively absolve both parties (the government and the renewable developer) of any responsibility for managing VRE intermittency and supporting hedge contract market liquidity.

In principal, VRE production subsidies need not have broken the physical-financial link if policy options for individual VRE plant to make their output more dispatchable had been encouraged. There has been some innovation in business models with new players seeking to build a portfolio of VRE and firming generation. A small number of VRE plant have co-located battery storage, albeit of limited duration (storage capacity equivalent to 1-2 hours of continuous discharge), principally to help with frequency and voltage control (Rai & Nunn, 2020). Due to their limited duration, such storage technologies are not currently able to 'firm' VRE output on their own. Therefore, despite a sizeable and growing dispatchability premium especially in high-VRE

[2] A reviewer of this manuscript made the salient observation that PPA counterparties (e.g. retailers) are still required to manage the intermittency risk associated with VRE generation. In this context, a key recent evolution has been the development of integrated renewable businesses that build a portfolio of VRE and firming assets and sell retail supply agreements and wholesale swap contracts, effectively pricing VRE intermittency risk (see Simshauser, 2020).

penetration regions like South Australia – which should incentivise VRE plant to make their output firmer – individual VRE plants remains largely non-dispatchable[3] (Rai & Nunn, 2020).

While Simshauser & Tiernan (2018) note that, in considering the optimal climate change policy some form of emissions trading scheme would be preferential, it is important to improve the operation of production subsidies given their extensive use throughout Australia and internationally. Australia, in particular, is deploying significant numbers of production subsidies such as the Small-Scale Renewable Energy Target (SRES), the Large-Scale Renewable Energy Target (LRET)and the Victorian Government Contracts for Difference (VRET). The Australian Capital Territory also has a target of purchasing 100% of its power from the cheapest renewable sources (i.e. VRE plant). As such, the purpose of this paper is to explore two design options which correct for the limitations noted above: making subsidies a function of the wholesale electricity price, demand or emissions; and requiring projects to demonstrate supply of wholesale electricity derivative contracts in order to receive subsidies.

This article is structured as follows: Section 2 provides a brief overview of the theoretical and applied literature in relation to the limitations of production subsidies in electricity markets; Section 3 provides a detailed explanation of our two proposals to overcome the limitations of production subsidies; and Section 4 concludes with brief recommendations for policy makers.

2. Brief literature review: the limitations of production subsidies in electricity markets

Australia has found it particularly difficult to address the issue of climate change for the past two decades (Simshauser & Tiernan, 2018). This is despite the science being relatively clear that Australia's contribution to global emission reduction efforts requires a carbon budget of no more than around 10 Gt of emissions between 2015 and 2050. Such a budget implies reductions of around 50% of 2005 levels by 2030 assuming a linear trajectory between now and 2050. A range of mechanisms have been introduced and, in some cases, abandoned. These have included carbon

[3] While VRE output can be controlled down, the technical characteristics of existing VRE plant in the NEM means VRE output cannot be controlled up (i.e. increased). Consequently, VRE output is considered non-dispatchable.

taxes, emissions trading schemes and the utilisation of production subsidies. All of these policies have explicitly, or implicitly, sought to internalise the externality of emitting greenhouse gases. Simshauser & Tiernan (2018) provide a comprehensive overview of the history of climate policy in Australia.

Pigou (1920) laid the intellectual framework for demonstrating how to 'internalise' the externality of costs and benefits incurred by society but not necessarily by individual firms and consumers. Equating private marginal costs (costs of the firm) to social marginal costs (costs to society) is a core consideration when evaluating options for addressing negative environmental externalities. However, there may be other reasons why policy makers may seek to use production subsidies, despite them being economically less efficient for achieving the goal of equating marginal social costs and benefits. For example, Held *et al*. (2019, p. 81) note that:

> '*We conclude that there are good reasons to continue dedicated RES-E policies beyond 2020 for those technologies. Dedicated RES-E support can provide a predictable, secure investment framework that lowers the risk premiums required by investors and therefore reduces the capital costs of RES-E. In addition, there are still significant cost reduction potentials for these technologies. The increased use of renewables has multiple socio-economic benefits in addition to climate change mitigation. These arguments are still valid when looking at the current market situation characterized by oversupply and low prices on both the CO2 market and some power markets in Europe. Since renewables are not the main reason for the current oversupply, it would not be effective to take actions towards restoring market equilibrium in the form of radical or overall phase-out of RES-E support.*

For many of the reasons noted by Held et al (2019), renewable energy production subsidies have been used in Australia, with a particular focus on *variable* renewable energy. A range of VRE production subsidies have been implemented over the past two decades, including:

- reverse auctions and subsidies funded by governments (e.g. reverse auctions in the ACT, Victoria and Queensland for large scale VRE)
- premium feed-in-tariffs (PFiTs) (e.g. various state-based feed in tariffs for household solar PV)
- market-based approaches that create a price for cleaner generation (e.g. Large-Scale Renewable Energy Target)
- direct research and development funding (e.g. Australian Renewable Energy Agency: ARENA) for VRE plant, and
- subsidised financing for certain VRE technologies (e.g. Clean Energy Finance Corporation: CEFC).

Many studies have historically found VRE production subsidies in Australia have higher average costs of greenhouse abatement than tax and trading schemes (AEMC, 2016, is an example). However, in many ways this is due to the lowest cost form of abatement historically being coal-to-gas switching, abatement from existing plant, and energy efficiency, rather than investing in new renewable energy. However, as noted by Nelson *et al.* (2019), solar PV and wind are now the cheapest forms of electricity generation. Given this, and the trebling in gas prices since 2010, new VRE output is presently the lowest-cost form of longer-term greenhouse gas abatement. This is especially likely to be the case under deeper decarbonisation targets, under which abatement from existing high-emissions plant may not be sufficient to achieve the target. As such, the use of VRE-focused production subsidies has intuitive appeal to policy makers.

The literature is clear that there are two key limitations in relation to VRE production subsidies in electricity markets (see Simshauser, 2020):

1. An accentuated merit-order effect due to inter-temporal misallocation of resources that incentivises coincident production from plant whose output are both correlated with each other (this is the case for wind and especially solar PV) and poorly correlated with demand.[4]
2. A reduction in the liquidity and availability of firm hedging contracts supplied by thermal plant as these energy sources are substituted with variable renewable energy (i.e. wind and solar).

These two limitations are considered below.

2.1 Accentuated merit-order effect

The merit order effect is well documented in the academic literature, dating back to at least 2008. Earlier studies tended to focus on the impact of introducing very low short-run marginal cost technologies such as wind (Sensfuss, Ragwitz and Genoese, 2008; Poyry, 2009; Pirnia, Nathwani and Fuller, 2011; Gelabert, Labandeira and Linares, 2011; Felder, 2011). These studies noted that VRE production subsidies tended to reduce wholesale electricity prices in the short-term but also that economic welfare was not necessarily enhanced. Felder (2011) and Nelson et al (2011, 2012) stated that the merit-order is a transient phenomenon.

The merit-order effect is perhaps best explained through the use of simple partial equilibrium analysis. Figure 1 shows a hypothetical energy industry aggregate supply function given by the curve (γ). This stylised supply curve shows the short-run marginal cost (SRMC) for a power station fleet with thermal coal and gas and hydro power stations. All of these units are able to choose when to be dispatched. They hold fuel in the form of coal bunkers, gas pipeline storage and water dams that can be used when called upon. They are discretionary (or 'dispatchable') generators.[5] In this hypothetical analysis, demand is shown for peak periods (d_P) and for off-peak

[4] For example, wind output in South Australia is *negatively* correlated with demand (Rai & Nunn, 2020).
[5] While "dispatchability" does not have a universal meaning, it is commonly considered as the extent to which the resource (i.e. demand or supply resource) can be relied on to 'follow a target' in relation to its load or generation. "Dispatchability" therefore incorporates notions of controllability and flexibility

periods (d_o). We are able to determine both consumer surplus (represented for off peak by the light-shaded triangle area marked ap_oe_o) and producer surplus in the off-peak period (cp_oe_o) and peak period (cp_pe_p).

Figure 1: Aggregate energy industry supply and demand with limited VRE[6]

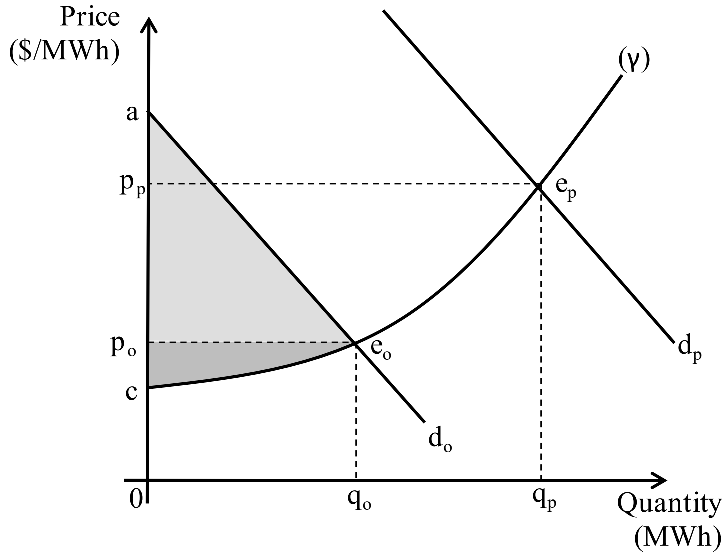
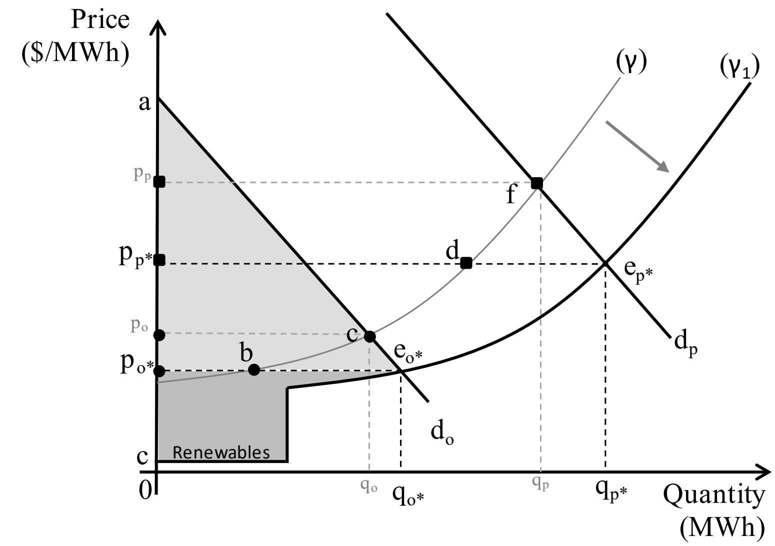


Figure 2 demonstrates the impact of the merit-order effect when VRE production subsidies incentivise the deployment of very low SRMC VRE generators. The aggregate supply function is shifted downwards and to the right, from curve (γ) to curve (γ_1). In turn, this lowers the equilibrium clearing prices in the off-peak and peak periods, from p_o to p_{p^*} and p_p to p_{o^*}, respectively. Effectively, there is a transfer of producer surplus from incumbent generators to consumers in the form of higher consumer surplus. The transfer of wealth in off-peak periods is the area given by the black dots labelled $p_{o^*}bcp_o$. The transfer of surplus in peak periods is represented by the black squares labelled $p_{p^*}dfp_p$. So, the merit order effect is effectively a transfer of producer surplus from incumbent generators to consumers.[7]

[6] Our partial equilibrium analysis is drawn from the earlier work of Nelson et al (2012).

[7] This is not necessarily problematic as a static finding when considering that many of the existing generators produce greenhouse gas emissions, and therefore a reduction in producer surplus is one way of reducing the gap between marginal social and private cost.

Figure 2: Energy industry aggregate supply and demand including new VRE[8]



Simshauser (2019) notes there are three sub-components of this partial equilibrium analysis:

1. a price impression effect – the phenomenon whereby VRE plant enters the system
2. the flexibility effect – whereby both VRE and incumbent plant are both available, and
3. the stochastic production effect – whereby dispatchable firm generation is required for reduced capacity factor operation when variable renewables are not producing (e.g. evening peak demand).

In the long-run prices must return to levels that recover the LRAC of an efficient system or investment will not continue to be forthcoming (Nelson *et al.*, 2018). As prices fall, there are two drivers of higher prices in the long-run. Firstly, there is a capacity factor utilisation effect. As incumbent generators are run sub-optimally, they become higher cost as operating and maintenance costs are spread over reduced operating hours. These generators also become less reliable over time and are replaced with higher cost options that are better suited to complementing variable renewable energy.[9] Secondly, and more prominently, as incumbent

[8] Our partial equilibrium analysis is drawn from the earlier work of Nelson et al (2012).
[9] The most notable example of this is the announcement by AGL Energy to replace the Liddell power station with a suite of low capacity factor non-coal options.

plants exit the market, the rebound effect results in prices returning to the long-run average cost of an efficient optimal plant mix.

The merit-order effect is well studied in Australia. Studies utilising Australian NEM data have focused on the impact of new VRE plant on the price duration curve (see MacGill, 2010; Forrest & MacGill, 2013; Cludius *et al*., 2014; Bell *et al*., 2015; Bell *et al*., 2017). Much of this work is focused on understanding the nature of coincident production of variable renewables with energy market design. More recently, Marshman, Brear, Jeppesen & Ring (2019) have demonstrated that an energy-only market can indeed be robust with up to 60% of its energy being provided by very low SRMC VRE plant. Rai & Nunn (2020) reach a similar conclusion based on the empirical evidence from South Australia.

Nelson *et al*. (2019) show that VRE production subsidies tend to accentuate the merit-order effect. As the VRE generator receives a subsidy for producing a unit of energy at any time of the day, they are able to generate to the point where prices in the wholesale electricity market decline to the negative value of the subsidy. This leads to significant coincident production of correlated output from specific technologies such as wind and solar. As Nelson *et al*. (2019, p. 186) state:

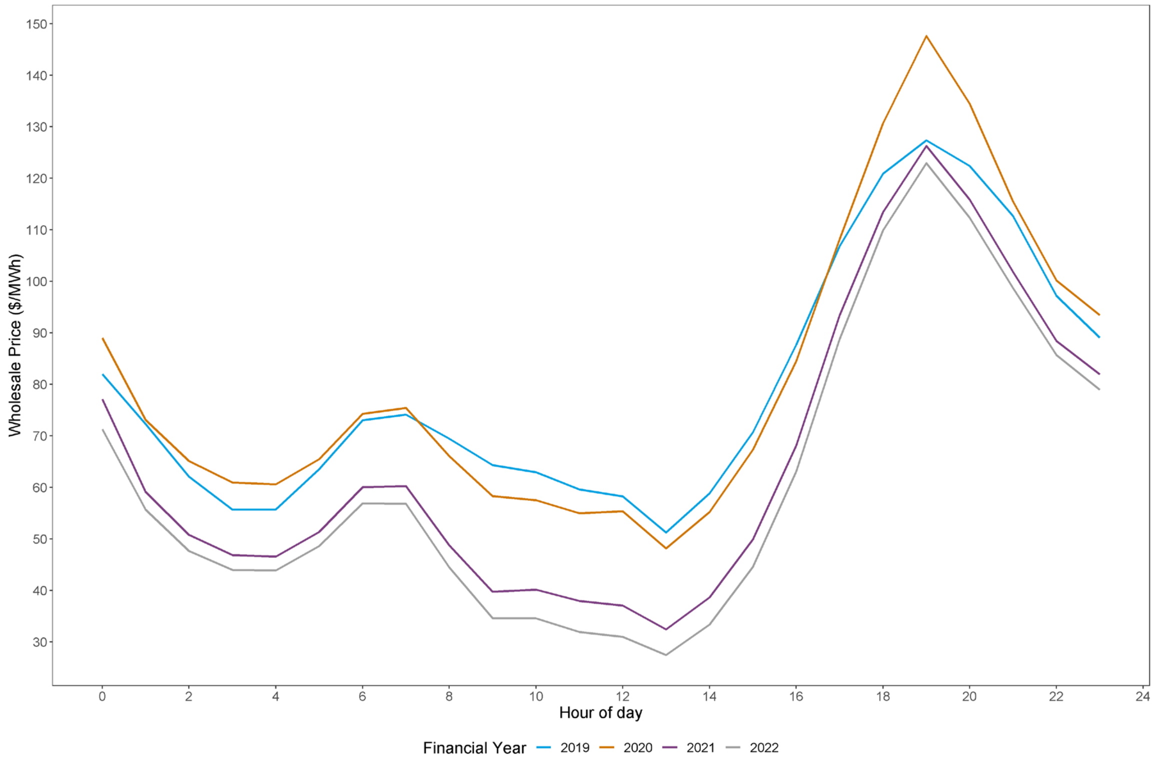
> *The use of production subsidies for variable renewable energy technologies not only results in a break between the physical needs of the system and financial outcomes, it results in a sub-optimal deployment of these technologies. Variable renewable energy technologies suffer from the 'coincident production problem'. As a result of only producing when fuel is immediately available and not stored (i.e. the sun is shining and the wind is blowing), there is often an 'oversupply' of energy from these coincidentally producing technologies.*

VRE production subsidies such as renewable energy trading schemes, PFiT and CfDs all tend to accentuate this merit order effect because the subsidy component values all output homogenously at the same price. This is despite the fact that there is a substantial difference in the value of electricity production over the course of a day and through a year. Simshauser (2019, p. 4) notes:

> *While the physical properties of electricity are largely homogeneous over space and time, from a market perspective there is rich price variation over time, space, and lead time-to-delivery, making the traded commodity a heterogeneous good (i.e., due to an inability to arbitrage, the absence of a single dominant technology, and variations in marginal costs).*

Nelson *et al*. (2019) demonstrate that by accentuating the merit order effect, production-based subsidies result in new variable renewable generation 'cannibalising' the wholesale electricity prices of other variable renewables. Using quantitative evidence from South Australia, where around half of the energy consumed is now sourced from variable renewables, they estimate the spread between the firm dispatch-weighted price and the price received by variable renewables has grown from $10 per MWh in 2010 to around $20 per MWh in 2018 (see also Rai & Nunn, 2020). Nelson *et al.* (2019, p. 187) conclude, 'In the absence of policy reform, the continued use of production subsidies will not result in an optimal investment mix. Participants will be incentivised by maximising production at any time rather than investing in an optimal mix of investments that lowers the overall cost of reducing greenhouse gas emissions.'

Figure 3: Projected price duration curves across the NEM



Source: Rai et al (2020)

Rai *et al***.** (2020) model a more pronounced merit-order effect, via a shift in the price duration curve (PDC), as the VRE penetration increases. In particular, the PDC is expected to be increasingly 'hollowed out' in the middle of the day, and increasingly 'peaky' in the early evenings (Figure 3).

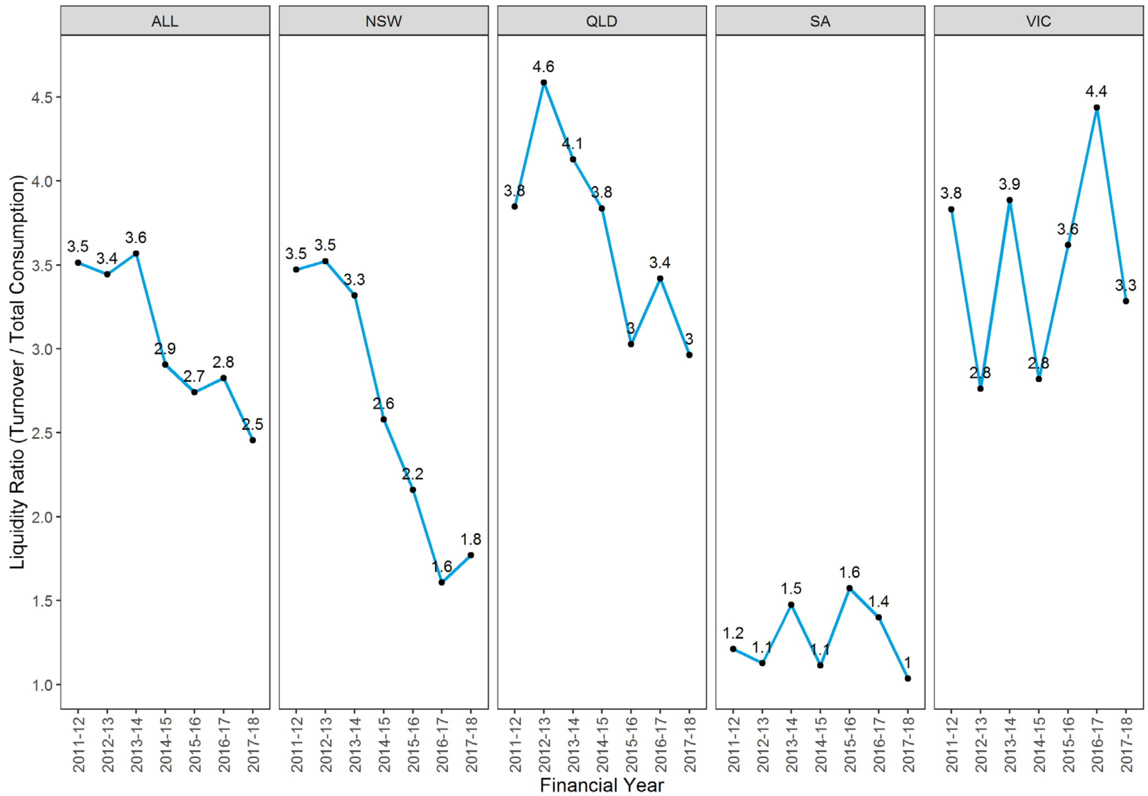
This accentuated merit-order effect driven by VRE production subsidies is effectively breaking the link between the financial incentives facing generators to generate a unit of energy and the physical needs of the electricity system. It is also driving a more 'disorderly' transition to firmed renewables. While it is true that the value of reducing a unit of greenhouse gas emissions is the same irrespective of the source of that emissions reduction[10], it is not true to state that it has the same value in the electricity market. To effect decarbonisation in the electricity sector, it will be necessary for production subsidies to provide greater value to abatement that occurs through production of electricity when its value is high, not just when it is windy and/or sunny. We propose possible enhancements to production subsidy designs in Section 3 to overcome this.

2.2 Lack of financial wholesale market hedging arrangements

The second major shortcoming of existing VRE subsidies is their impact on hedge market liquidity. Rai & Nunn (2020) note, wind output and demand in South Australia is typically *negatively* correlated. There is limited incentive for VRE plant to enter into 'firm' forward hedging contracts, such as fixed-output or load-following swap and cap contracts, when renewable PPAs are available instead. These long-term agreements between generators and retailers or large consumers involve the purchase of all of the energy from a particular wind or solar project. Unlike 'firm' hedging contracts, PPAs reward the seller for generating as much electricity as possible at any time; there is no financial signal for the seller to generate more or less electricity when spot prices are high or low. PPAs structured in this way break the link between financial incentives and the physical needs of the system.

[10] Climate change is global in nature and relates to the stock of emissions in the atmosphere and not the flow at any point in time.

Figure 4: Liquidity ratios in the NEM



Source: Nelson *et al*. (2019)

Nelson *et al*. (2019) note that increased VRE penetration has led to reduced liquidity amongst firm hedge contracts (see their analysis reproduced in Figure 4). However, as noted earlier, there are new business models[11] emerging that seeking to overcome some of the limitations imposed by the 'least-worst' interventions (see Simshauser, 2020). These new models involve pricing intermittency risk and offering wholesale financial hedge contracts that are physically backed by VRE. It is positive to note that the NEM-wide liquidity ratio increased significantly in 2019/20 to 4.8 (turnover/total consumption).

[11] See for example the business model adopted by Infigen Energy (https://www.infigenenergy.com/) and the new hedge products offered by the Renewable Energy Hub, backed by ARENA (https://www.renewableenergyhub.com.au/). Accessed online on 9 December 2020.

Over the past ten years, around 5,000 MW of dispatchable generation has exited the NEM, while close to 10,000 MW of utility-scale VRE plant entered the market (Rai & Nunn, 2020). The exit of dispatchable plant (such as hydro, and coal- and gas-fired plant) has largely been VRE induced. Such plant has traditionally provided firm hedging contracts. Policy measures that drive new investment in VRE will need to be adjusted to ensure that incentives continue to exist for market participants to price intermittency risk given the importance of the interaction between the futures and spot markets identified in Section 1.

3. Overcoming the limitations of VRE production subsidies

In this section, we propose two adjustments that could be made to VRE production subsidies that would correct for the unintended consequences and limitations noted in the preceding Section:

1. the quantum of the subsidy could be a function of the wholesale electricity price, electricity demand or emissions in the electricity market; and
2. new generators would be ineligible to receive production subsidies without demonstrating that they are facilitating the supply of financial derivative contracts.

The effect of either adjustment would be to: increase the incentive of VRE plant to more align its output with either price or demand; that is, make its output 'firmer'; and increase incentives for broader, strategic and more comprehensive electricity sector decarbonisation.

As VRE production subsidies are primarily provided via certificate schemes, under which one certificate is created for each MWh generated, our proposal is specified in terms of the quantum of certificates that can be created. This said, our proposal could also be applied to non-certificate schemes such as feed-in tariffs, where the dollar value of the FiT would be scaled by a factor that is related to either spot prices, demand or emissions, depending on whether the subsidy is a function of the spot price, a function of electricity demand or a function of the emissions intensity of the market.

3.1 Temporal adjustment of subsidies – correcting for accentuated merit order effects

(a) Linking the quantity of subsidy with wholesale spot prices

A means of imbuing a demand-related temporal value to VRE production subsidies is to make the volume of certificates created dependent on both the output from the VRE plant and the prevailing spot price. The price of the certificate would be determined in the open market, by the forces of demand and supply, as currently occurs under the LRET.

This alternative volume-creation scheme would have the following broad functional form:

$$Q_{i,certificate}^{t,x} = f\left(Price_{SPOT}^{t,x}, Q_{i,MWh}^{t,x}\right) \tag{1}$$

where $Q_{i,certificate}^{t,x}$ is the volume of certificates created by generator i at time t in region x, $Price_{SPOT}^{t,x}$ is the corresponding spot price, and $Q_{i,MWh}^{t,x}$ is the corresponding output from generator i, and $f(\cdot)$ is the specified functional form. Tying the generation of certificates to the marginal value of generation at a point in time acts to *amplify* the spot price signals for eligible generators. In contrast, the volume of certificates under existing VRE production subsidies is solely dependent on the output of the relevant plant. That is, $Q_{i,certificate}^{t,x} = Q_{i,MWh}^{t,x}$, with 1 MWh of output equal to one certificate.

Linking certificates to spot prices would reallocate some plant volume risk from consumers back to generators, and in turn induce additional volatility into the creation of certificates. While the potential impact on plant revenues is likely to be negative for VRE plant whose output is poorly correlated with demand and spot prices (such as South Australian wind plants), it will provide incentives to create portfolios of variable renewables, storage and peaking plant that add more value to both the proponent and the system.[12] Hence, the volume (and therefore value) of certificates for prospective non-dispatchable plant are likely to be lower than for dispatchable credit-eligible plant, as per the design of the certificate-creation scheme in equation (1).

In deciding the appropriate functional form, it is important to balance the following issues:

[12] Energy storage could be used to create additional demand during low pricing driven by co-incident VRE production, thereby lifting prices and allowing production subsidies to be retained.

- linking financial incentives with the needs of the physical system – in our view, spot prices are the most appropriate signal for the physical needs of the system. Since spot prices vary every five minutes, the volume of certificates created could similarly vary every five minutes (holding $Q_{i,MWh}^{t,x}$ constant)
- project financing considerations – additional volatility in the creation of certificates, by linking their volume creation to spot prices, could create more revenue volatility for both variable renewable and non-variable renewable plant, thereby increasing the cost of capital, project hurdle rates of return, or both. This may increase the cost of emissions abatement all other things being equal, and
- the extent to which the certificate-creation scheme in equation (1) departs from the design of existing policies. The more that such a scheme departs from existing policy design the greater the need to consider transitional issues for any existing proponents. In fact, existing projects currently operating could be grandfathered using current certificate quantity calculations.

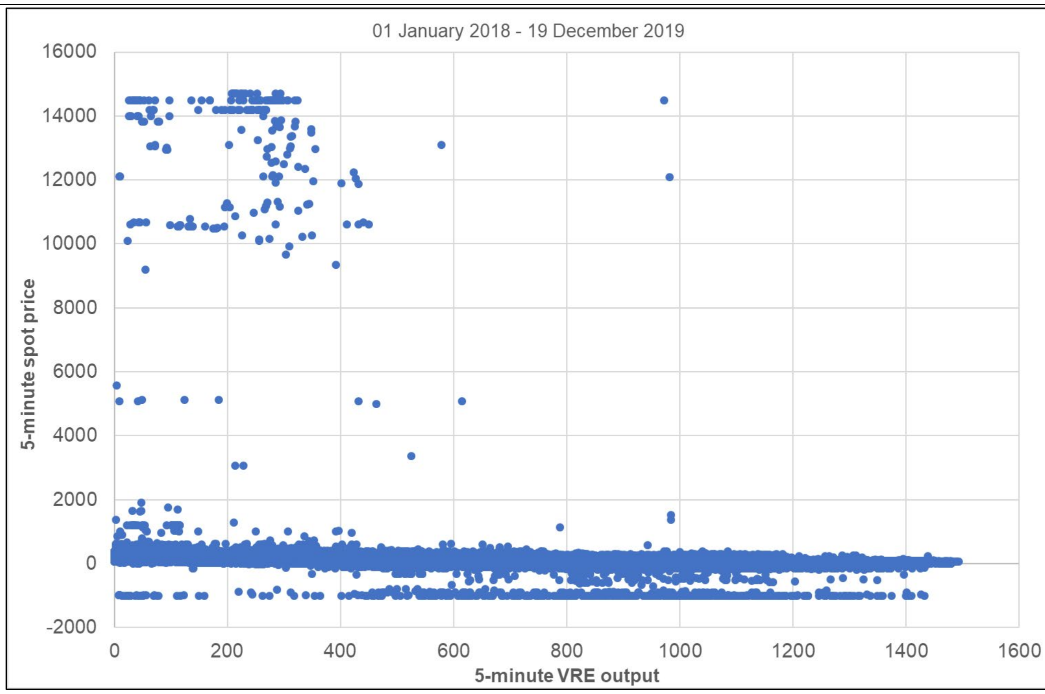
Balancing these considerations suggests a functional form that is relatively easy to understand whilst, broadly speaking, linking physical needs with financial incentives. We propose that the following functional form could be considered for new projects:

$$Q_{i,certificate}^{t,x} = \begin{cases} Q_{i,MWh}^{t,x} \; when \; Price_{SPOT}^{t,x} \geq X \\ 0 \; otherwise \end{cases} \tag{3}$$

Under this binary model, either zero or one certificate is created for each MWh of output from variable renewable plant, depending on the prevailing spot price. X is the floor spot price below which no certificate is created. This could be linked to the short-run marginal cost (SRMC) of variable renewable plant or the SRMC of the most inflexible plant in that region. The SRMC of Australian wind plant is estimated to be \$5/MWh (Graham *et al.*, 2018).

Using the example of VRE plant (chiefly, wind) in South Australia over the January 2018 to December 2019 period, this function would imply a significant change in the operation of VRE plant (Figure 5). Over this 24-month period, 10 per cent and 20 per cent of VRE output was below the $X = \$5/MWh$ and $X = \$20/MWh$ levels, respectively.[13]

Figure 5: VRE output and spot prices in South Australia



By linking VRE production subsidies to the physical needs of the system, reflected through the spot price, investors will be more incentivised to develop a portfolio of assets that better minimise total system costs and at the same time achieve decarbonisation goals. This could include variable renewables and gas-fired plant in the short-term and variable renewables, demand response and storage in the long-term. Such an approach would avoid the current problem where firm dispatchable plants are being de-committed at times of high variable renewable production. This de-commitment problem is especially problematic in South Australia, where gas plant often de-commit in anticipation of low spot prices induced by high wind generation (AEMO, 2019). This in turn has led the market operator (AEMO) to intervene in the spot market, directing these gas plant to stay online to maintain system security. This approach to maintaining system security is

[13] $X = \$20/MWh$ is estimated to be the SRMC of brown coal plant (Graham et al., 2018). Over this 24-month period, the correlation between demand and price is -0.14.

estimated to be around $176 million for South Australia for the 2017-2019 financial years (Rai & Nunn, 2020).

The value of X should be binding. That said, setting too high a value of X could result in an inefficiently high reallocation of volume risk to individual variable renewable plant operators. That is, it may be more efficient for an off-taker to hedge some of the volume risk from one VRE plant by diversifying across PPAs, rather than for an individual VRE plant to manage all its volume risk. This may especially apply for the largest off-takers in the NEM.

As an alternative to a binary option, a more graded option could be used; for example, the following equation (4):

$$Q_{i,certificate}^{t,x} = \begin{cases} Q_{i,MWh}^{t,x}\ when\ Price_{SPOT}^{t,x} > X_4 \\ 0.8 * Q_{i,MWh}^{t,x}\ when\ Price_{SPOT}^{t,x} \in (X_3, X_4] \\ 0.6 * Q_{i,MWh}^{t,x}\ when\ Price_{SPOT}^{t,x} \in (X_2, X_3] \\ 0.4 * Q_{i,MWh}^{t,x}\ when\ Price_{SPOT}^{t,x} \in (X_1, X_2] \\ 0.2 * Q_{i,MWh}^{t,x}\ when\ Price_{SPOT}^{t,x} \in [X_0, X_1] \\ 0\ when\ Price_{SPOT}^{t,x} < X_0 \end{cases} \tag{4}$$

In this example, certificates are created according to where the spot price lies in the price bands. As before, no certificates are created for generation that occurs when the price is below a certain level (X_0). When prices are above X_0, certificates are created according to a multiplier. The value of the multiplier increases, and therefore the quantity of certificates created per MWh of output increases, as the wholesale spot price increases.

(b) Linking the quantum of assistance with demand

Adding a demand-related temporal value to the creation of certificates provides another, potentially more cost-effective way of maintaining system security and linking financial incentives with system need. Under such an approach, VRE plant are incentivised to generate only demand is sufficiently high, which minimises the risk of over-supply of this output, and in turn minimises the risk that synchronous plant decommit only to then be directed on to maintain system security.

A demand-linked certificate-creation scheme could be, for example:

$$Q_{i,certificate}^{t,x} = \begin{cases} Q_{i,MWh}^{t,x} \text{ } when \text{ } D_{MW}^{t,x} \geq D_{MW}^{POE50} \\ 0.5 \cdot Q_{i,MWh}^{t,x} \text{ } when \text{ } D_{MW}^{t,x} \geq D_{MW}^{POE75} \\ 0 \text{ } otherwise \end{cases} \qquad (5)$$

Under this alternative, $Q_{i,certificate}^{t,x}$, is linked to the prevailing level of demand. In equation (5), one certificate is created for each MWh of output from VRE plant whenever that output coincides with demand above a POE50 level; that is, demand is above the level that would be expected to occur 50 per cent of the time. In contrast, only half a certificate is created for each MWh of output from certificate-eligible plant whenever that output coincides with demand above a POE75 level; output that coincides with demand below a POE75 level would not receive any certificates.

Again using the example of output from VRE plant in South Australia over the January 2018 to December 2019 period, 28 per cent of variable renewable output was below the D_{MW}^{POE75} level, meaning a 28 per cent reduction in certificates created under the proposed equation (3). In total, 43 per cent of variable renewable output would not be eligible for certificate creation based on equation (3).[14]

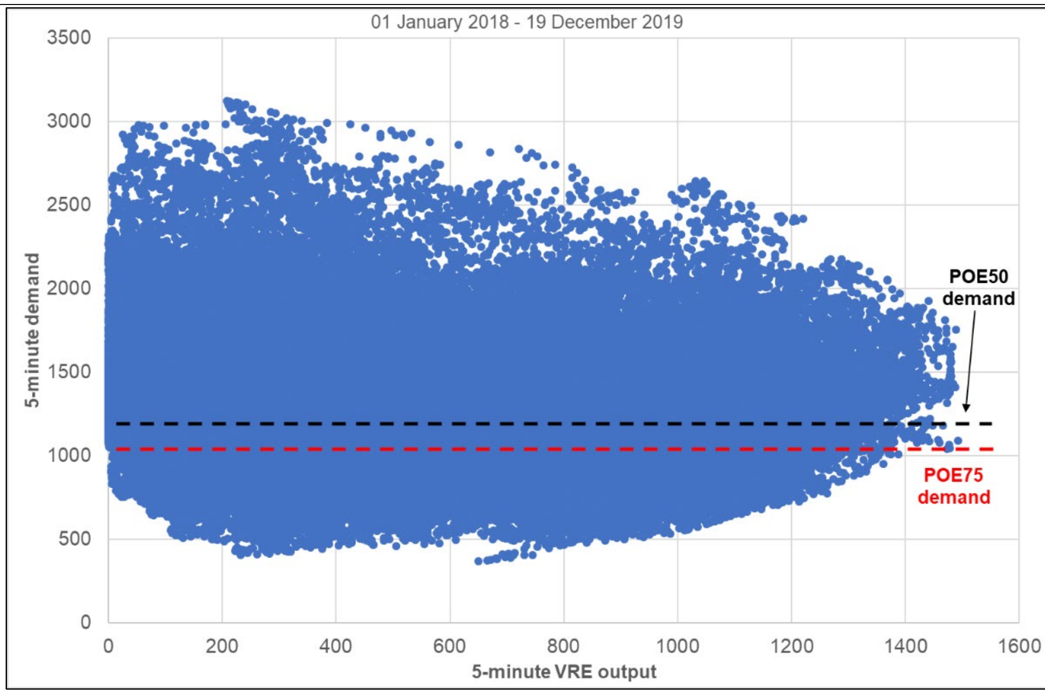
On balance, the price-based approach (i.e. equation (2)) would be preferable over a demand-based approach (equation (5)) for the following reasons:

- equation (5) is more complex than (2) due to the need to determine the appropriate POE levels, which can change over time and are not always easy to estimate. These measurement issues could induce potentially greater revenue volatility and consequent adverse impacts on project financing, and
- historically, the relationship between demand and spot prices has been strong, which meant the link between $Q_{i,MWh}^{t,x}$ and demand was (almost) equivalent to the link between $Q_{i,MWh}^{t,x}$ and price – and so equation (5) could be considered a more dynamic form of equation (2).

[14] Over this 24-month period, the correlation between demand and price is -0.09.

However, over time the demand-spot price relationship has weakened, which means (5) is likely to be less representative of system need than (2).

Figure 6: VRE output and demand in South Australia



(c) Linking the quantum of assistance with emissions

A hitherto unexplored policy opportunity may be to link the production subsidy to the overarching policy goal being pursued: a reduction in emissions. This alternative volume-creation scheme would have the following broad functional form:

$$Q_{i,certificate}^{t,x} = f\left(EI_{t/MWh}^{t,x}, Q_{i,MWh}^{t,x}\right) \qquad (6)$$

where $Q_{i,certificate}^{t,x}$ is the volume of certificates created by generator i at time t in region x, $EI_{t/MWh}^{t,x}$ is the emissions intensity of the market at time t in region x, and $Q_{i,MWh}^{t,x}$ is the corresponding output from generator i, and $f(\cdot)$ is the specified functional form. Tying the generation of certificates to the emissions intensity of the market effectively prices the externality of emissions through a production subsidy.

Generation with zero emissions that produces a unit of energy when the emissions intensity of the market is low would receive a lower quantum of subsidy than generation produced when the emissions intensity of the market is high. It would be necessary to consider whether the emissions intensity is regional or market wide and based upon the average intensity of a unit of energy produced, or the emissions intensity of the marginal generator. In practice, it would be inherently difficult to determine what the marginal generator would have been but for the intervention of the policy mechanism itself. As such, utilising the average intensity of the market at the point of generation would be preferable.[15]

3.2 Restoring contract market liquidity: firm-capacity credits

One means by which Australian policy makers have sought to address the VRE-induced decline in the liquidity of 'firm' hedging contracts is via the introduction of the Retailer Reliability Obligation (RRO). The RRO came into effect on 1 July 2019 and builds on existing spot and financial market arrangements in the NEM to facilitate investment in dispatchable capacity. The RRO requires retailers to hold 'firm' derivative style contracts for their share of demand. If a 'shortfall' is declared by the market operator, the regulator has the power to examine their contract position and assign any costs of emergency reserve procurement to retailers that are deemed to be non-compliant with the RRO.

The RRO, in combination with the market price cap (MPC) and cumulative price threshold (CPT) settings act to create incentives for retailers to enter into sufficient financial derivative contracts to cover the financial risk associated with the significant pricing volatility that can manifest within the NEM. As a policy mechanism, the RRO seeks to overcome the second of the limitations of production subsidies noted in Section 2. Retailers are incentivised to enter into

[15] This approach could be used to make the certificates created under a production subsidy fungible with other carbon abatement instruments (e.g. ACCUs). Existing generation would need to be grandfathered in some way to recognise the historical abatement that has occurred when the emissions intensity of the market was higher than present levels. It would also allow entities to purchase a 'positive' financial hedge for future emission reductions required outside the electricity sector.

financial derivative contracts as a means of avoiding regulatory sanction. In this context, the RRO acts as a policy tool to correct any failures on the demand side of the market for financial derivative contracts.

But as noted in this paper, the continued use of government Cfd policies is likely to disincentivise new VRE plant from entering into the types of firm hedging contracts contemplated under the RRO. There is therefore still a potential gap on the *supply-side* of firm hedging contract markets despite the RRO being in place.

Assuming governments continue to utilise Cfd policies (which we would not recommend), amendments should be considered to facilitate the effective operation of the RRO. As part of the architecture of a government Cfd program, policy makers could require generators to demonstrate that they have entered into, or supported the development of, financial derivative contracts for a proportion (e.g. 25 per cent) of the nameplate capacity of the new renewable project. Following verification by the regulator, the proponent would be allocated a 'firm-capacity certificate' which would be required to register to receive any form of Cfd. In this way, pricing intermittency risk would be partially resolved.

For example, to register a 100 MW windfarm to obtain a Cfd, the proponent would need to demonstrate that 25 MW (using the 25 per cent value noted above) of new firm financial derivative contracts have been entered into. The percentage of firm hedging contracts relative to nameplate capacity could be initially set low and increased over time as the proportion of variable renewable energy in the system increases.[16]

[16] This requirement could also be placed on existing dispatchable generators approaching the end of their engineering design life. Older generators could be required to nominate a closure date and demonstrate to regulators that they are entering into financial derivative contracts that support such closure arrangements. Such a requirement, in combination with the requirement on new VRE generators to enter into derivative contracts, would overcome the inter-period contract market volatility that violates real-world political economy constraints noted in Nelson *et al.* (2018).

3.3 Addressing potential long-term contracting issues

By virtue of its design – a volume-based scheme with known annual targets through to 2030[17] – the Australian 20% LRET enabled long-dated PPAs to be signed for eligible plant. This has overcome some of the risks associated with long-dated, heavy, fixed-cost infrastructure investment, particularly the presence of technology risk due to material projected cost changes in renewable and battery technologies. These risks are increasingly limiting appetite for long-dated PPAs and in turn creating risks for equity (and refinanced debt) investors in relation to 'tail merchant risk'.

Our proposed production subsidy design could similarly provide longer-term certainty, via a volume-based approach (like the RET) or, more preferably, an emissions reduction target-based approach. This could either be for the period to 2030 – if, for example, the electricity sector was required to do more than its pro-rata share of the economy-wide 26-28 per cent emissions reduction target – or post-2030.

However, in the absence of a sufficiently long end-date, it is worth considering mechanisms that can deliver sufficient certainty for equity and debt financiers of renewables. One mechanism could be similar to the underwriting new generation investment mechanism recommended by ACCC (2018). ACCC (2018) recommended the Australian Government enter into low fixed-price energy offtake agreements for the later years (e.g. 6 – 15) of new projects which meet certain criteria, such that projects can secure debt finance of sufficient amount and duration. In a similar way, a government-owned market 'aggregator' could be created to provide floor pricing for contracts beyond the tenor existing derivative markets currently operate within.

[17] The renewable energy target was set at 9.5 terawatt hours (TWh) by 2010. In January 2011, a target of 41 TWh by 2020 was set, but in June 2015 was subsequently revised down to 33 TWh by 2020. This annual amount remains unchanged through to 2030, which is when the LRET is scheduled to end.

4. Concluding remarks

Following abandonment of the emissions component of the National Energy Guarantee in 2018, it may well be that a nationally-consistent version of a certificated VRE production subsidy is the most viable option for meeting climate change goals given real-world political economy constraints. While economists would mostly contend that a well-designed emissions trading scheme would reduce emissions at lowest cost, VRE production subsidies are currently the preferred tool of choice for energy and climate change policy makers.

Policy makers in Australia are deploying significant numbers of production subsidies such as the Small-Scale Renewable Energy Target (SRES), the Large-Scale Renewable Energy Target (LRET), the Queensland Renewable Energy Target (QRET) and the Victorian Renewable Energy Target (VRET). As such, it is important to design these schemes to maximise benefits and minimise costs. With such an objective in mind, this paper has considered two variants on scheme design to overcome the two main limitations of these types of production subsidies: an accentuated merit-order effect; and reductions in financial derivative contract market liquidity, in the context of a lack of cost-effective storage at the individual VRE plant level.

We have confined our analysis to how these variants of design would be effective with a certificated scheme such as the Australian LRET. At the time of writing, at least three jurisdictional governments are continuing to use contracts for difference (CfD) style production subsidies. Simshauser (2019) provides a good overview of why these types of policies can create unintended consequences. Our design variations on a certificated VRE production subsidy indicate that renewable energy objectives can indeed be fulfilled with production subsidies that link the physical needs of the system with the financial incentives facing investors.

Our policy recommendations are to adjust VRE production subsidies so that: the quantum of subsidy for new projects would be a function of the wholesale electricity price or electricity sector emissions; and new generators would be ineligible to receive production subsidies without demonstrating that they are facilitating the supply of financial derivative contracts. Existing frameworks such as the LRET policy architecture could be used with existing projects continuing to create certificates using current methodologies, facilitating a single certificate price for both old and new projects. With these amendments in place in Australia, a nationally-consistent certificated VRE production subsidy framework could lower transaction costs whilst allowing individual jurisdictions to achieve their own specific renewable energy penetration or decarbonisation goals.

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