Designing Electricity Markets for High Penetrations of Zero or Low Marginal Cost Intermittent Energy Sources

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Abstract

This article explores key market design issues to be addressed in future electricity markets dominated by intermittent renewable generation with near zero private marginal costs for generating electricity. Changing technology mixes will change market outcomes, but they do not change the fundamental economic principles behind market design. Market-clearing prices in such a market are not necessarily mostly zero even in an energy-only market, especially with grid scale storage, an active demand side of the market, and scarcity pricing. However, increasing intermittent generator penetration increases the importance for adequately pricing scarcity and all network constraints and services. Such pricing is required to deliver investment incentives for the right technologies to locate at the right locations to efficiently maintain a stable and reliable electrical network.

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1 Introduction

Integrating intermittent renewables into electricity markets has raised concerns about the market's volatility and ability to deliver reliable power. These concerns stem from the zero private marginal costs of generation and intermittency of renewable electricity generation, with some expressing the view that energy-only markets will break (Edenhofer et al., 2013; Helm, 2019; Thompson, 2019) and thus require a fundamental re-think.

In this paper, we acknowledge that the penetration of intermittent renewables will change electricity market outcomes, but outline why their penetration does not change the fundamental principles behind efficient market design. For economists, approaching a market design problem entails the derivation of pricing and allocation rules. These rules usually interact supply, demand, and constraints in the environment to set prices that clear the market across space and time, with the aim for market outcomes to correspond to the best possible social outcome (Schweppe et al. (1988)). Thus, to improve the social outcomes of electricity markets, a focus of market design is on ensuring all players in the market face efficient price signals.

We argue that the introduction of intermittent renewables does not change the fundamental features of existing electricity markets, nor does it introduce any new forms of fundamental market failures.[1] The extent to which existing markets fail to reliably and efficiently integrate intermittent renewables will be linked to existing mispricing that results in a disconnect between the private incentives facing individual participants and the social (whole-of-system) impact of their actions. Many market inefficiencies that are being revealed in areas with growing penetration of variable renewable energy (VRE) sources can

[1]The market failure arising from carbon emissions is a related issue that should be addressed by appropriate carbon pricing. While a carbon price may affect the optimal mix of fuel sources, the principles to efficiently price electricity and its transmission given a carbon price remain unchanged. Newbery et al. (2018) also point out potential learning externalities associated with renewable technology adoption. However, these do not affect the operation of price signals as we discuss in this paper.

be prevented by adopting effective market designs that are more robust to technological change.

Ultimately, we argue in favor of evolution rather than revolution by continuing to apply core economic principles to market design. We emphasize that high penetration of energy sources that have zero private marginal costs when generating electricity does not mean the marginal costs to the system associated with additional generation, or the market-clearing price, will be zero. Moreover, many of the legitimate concerns regarding system resilience and the ability to meet demand can be addressed by allowing market participants to face market prices that vary across time and space, incentivizing an economically efficient use of resources in the short run and investment in the most suitable technologies at the right locations in the long run. We note the incompatibility of capacity markets to efficiently deliver long-run resource adequacy in settings with high VRE penetration.

We first review the economic principles behind market design and then examine how the penetration of zero private marginal cost sources will change electricity market outcomes. We then examine the role of price volatility and in particular its role in incentivizing storage investment and flexibility in demand. The penultimate section discusses the missing price signals and resource adequacy options in Australia's National Electricity Market, a zonal, energy-only market. We then conclude the paper.

2 The fundamentals of market design are technology invariant

A market design has three components: An allocation rule, a pricing rule, and an exclusion rule. For example, a first-price auction is a market design that can be used to determine property ownership, where the property is allocated to the highest bidder – the allocation rule – among the registered bidders – the exclusion rule – and the price set by that bid – the pricing rule. An economic framing of the market design problem is to set these rules to maximize some objective, usually social welfare (the sum of the benefit provided to all consumers[2] and all producer profits).[3] This framing of the market design problem is technology invariant.

In the context of electricity markets, market design refers to the rules that determine the allocation and pricing of the production and consumption of energy and other network services. A pronounced characteristic of electrical networks is that the impact on social welfare from an injection of energy into a network can (greatly) differ over time, location, and even by the technology that performs the action.

Cramton (2017) argues that a well-designed electricity market should satisfy the twin goals of short-run efficiency – making the best use of existing resources – and long-run efficiency in promoting investment in new resources. Bohn et al. (1984) introduced solutions for optimal short-run spot prices and allocations for electricity markets, maximizing social welfare conditional on not violating the constraints on the system, such as maximum generating unit capacities and transmission capacities. This methodology provides the foundation for the locational marginal prices (LMP) that define nodal market designs.[4]

Although Bohn et al. (1984) primarily focus on modeling transmission constraints and system losses, their core insights are more generally relevant – participants should face prices that reflect the whole-of-system impact of their actions on the margin.[5] For example,

[2]Consumer benefit is the difference between the willingness to pay and the price paid for each unit of output consumed. A welfare-maximizing allocation of generation and consumption means that if any participant were to incrementally increase or decrease their output, social welfare would decrease. See Garcia et al. (2009) for an introduction to these concepts in an electricity setting. The framing does not consider environmental externalities but can easily accommodate them.

[3]The mission of the Australian Energy Market Commission is more consumer focused: "To improve consumer outcomes from the strategic development of energy markets, through rules and advice."

[4]Bohn et al. (1984) assume that participants bid/offer at their marginal cost and willingness to pay. In practice, system operators usually maximize "as-bid" social welfare.

[5]See Cramton (2017) and Wolak (2019a) for discussion of the importance of electricity market designs

generator actions that put pressure on system constraints might receive relatively low prices, and those that relieve pressure on system constraints might receive relatively high prices. These spot prices also incentivize investors in new resources to look for technologies and locations where they can provide the greatest system efficiency gains. With scarcity pricing, prices will exceed costs for all generators in some market conditions and allow for investments to recover fixed costs, as we discuss in more detail in Section 3.

In the face of increasingly cheaper VRE sources and subsequently greater penetration of VRE, the principles behind the prices and allocations in Bohn et al. (1984) hold true – the economic value of additional generator output (or a demand reduction) will vary across time and location, and prices should reflect these differences. Actions in one period can also have economic impacts in another period due to intertemporal links between generating costs and consumption behavior (for example due to ramping costs, or the opportunity costs of releasing stored electricity or water). Therefore, the economic impact of participant actions can include both static and dynamic spillovers, motivating multi-settlement market designs such as a day-ahead market for the optimal scheduling of resources and a real-time market for security-constrained economic dispatch (Cramton, 2017; Wolak, 2019a). Finally, economic impacts might also vary by technology type. For example, system operators might impose requirements for additional operating reserves in periods where output from intermittent sources is high as a contingency in the event of sharp changes in weather or network conditions.[6] Pricing the whole-of-system impact of participant actions will mean they internalize their impact on social welfare and will encourage short- and long-run efficient behavior and investment.

Clearly the penetration of VRE will change market outcomes and the value different

pricing all actions on the margin and having prices vary across time and space

[6]See Australian Energy Market Operator (2016) for an overview of the different properties of asynchronous VRE generating sources and synchronous generating sources and how they relate to system strength.

participants can create in electricity markets, but the principles underpinning the economic objective and framing of market design remain. Market models that incorporate all physical network constraints, even if currently non-binding, when deriving prices and allocations will provide investment incentives that will help make a market design robust to technological change.

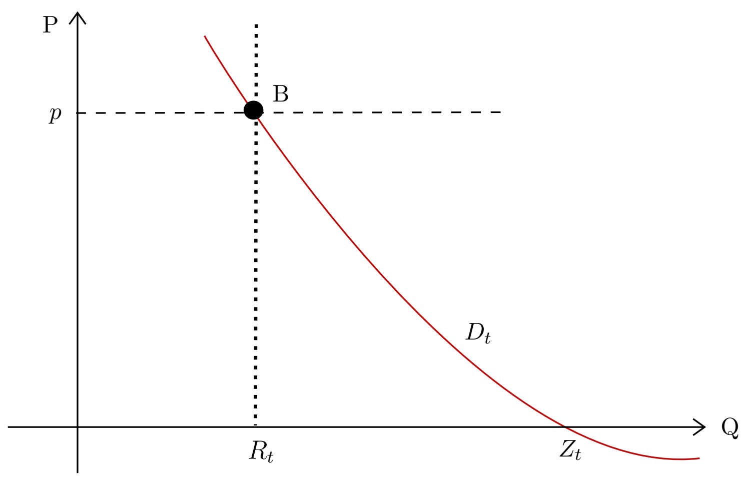
3 Markets function with low short-run marginal costs

Markets for any product that has zero marginal cost of production but elastic demand have an average market clearing price greater than zero. Consider a stylized wholesale electricity market with no network constraints, elastic demand and a 100% intermittent renewable energy supply. Figure 1 outlines the market, where p is the price of electricity, Q_t is its quantity, D_t is the demand curve (which will fluctuate with weather conditions, time of day etc), and R_t is the supply of intermittent renewable power. This supply curve (which will move from left to right with changes in weather conditions) is vertical because all available power is supplied to the market regardless of price, as the marginal cost of generation is zero and operators cannot schedule generation. The market clearing price is determined at B. Only if the R_t curve is to the right of the point where D_t is zero (at point Z_t) will the price of electricity will be zero or negative. If average prices do not cover total costs then we would expect in the long run for generation capacity to exit the market and prices to rise.

However, the above claim hinges on having some elasticity of demand that, for specific historical reasons, is not presently observed in most wholesale electricity markets, and as a result prices could be very volatile in such future markets (Nelson and Orton, 2016). If this simple economic framing is to concern practitioners, it should not be due to the generators having zero private marginal costs, rather it would need to relate to the intermittency of

VRE combined with the assumed, continued inelasticity of demand for energy and issues regarding system security. Further, corporate financiers generally require long-horizon forward contracts to fund new investment, which participants are experiencing more difficulty in obtaining (Simshauser, 2018), as the structure of contracts that are suitable for these changing output profiles differ from many of the traditionally structured contracts used in the industry. In Section 5 we examine some missing prices and market design features in Australia's National Electricity Market that might mitigate these practical concerns.

Figure 1: Stylized wholesale electricity market with elastic demand and no network constraints

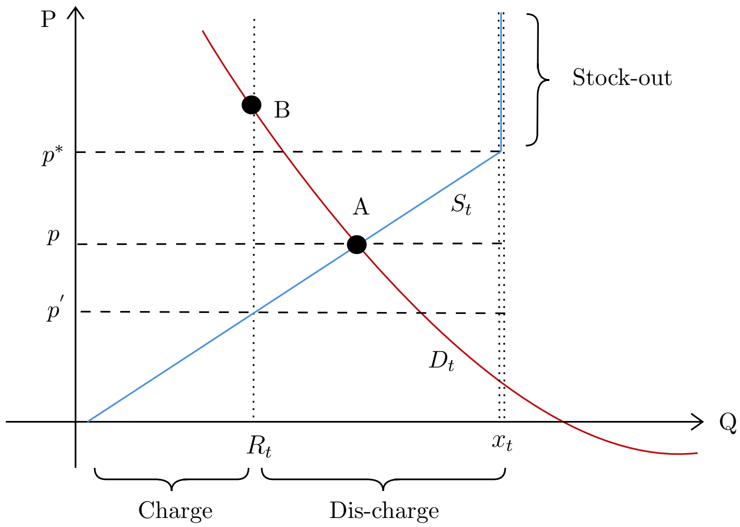


3.1 Electricity markets have always been characterized by high fixed cost / low marginal cost technologies

Beginning in the last quarter of the 20th Century, electricity markets were liberalized in many countries leading to the introduction of wholesale electricity markets (Green, 2005). These markets were designed for a world where the main generation sources were usually coal or nuclear power plants, which have high fixed costs and relatively low marginal costs. As these technologies are usually slow to ramp up or down, fluctuations in demand were mainly served by gas-fired "peaker" plants and/or hydro-electric power. In U.S. markets, the price of electricity is typically set by the relatively higher marginal costs of gas generators (Borenstein and Bushnell, 2015). Low marginal cost, high fixed cost sources can thereby cover their fixed costs as the average price of electricity exceeds their marginal cost (Borenstein, 2000).

In some markets, such as the Nordic market, hydro-power dominates the market. Hydro-power has high fixed costs and near zero marginal costs, but the price at which these generators bid in a market is not based on marginal production cost but on the opportunity cost of releasing water now versus in the future (Jahns et al., 2020). In future electricity markets, storage whether pumped hydro, batteries, or other technologies might play a similar role. In Figure 2, S_t is the (fluctuating) electricity supply curve that includes both the intermittent supply and the net supply from storage (and from production capacity reserved by the system operator to meet security constraints). The curve has a finite slope up to the price level p^* driven by the marginal opportunity cost of releasing electricity. The more electricity is discharged in the current period, the more valuable is the remaining reserved electricity, *ceteris paribus.* The market clearing price, p, is now determined at A, which is lower than the price at B. If demand is such that the price is below p', storage would have a net negative supply – that is storage operators would purchase electricity – and the price would be higher than in the absence of storage. Thus storage reduces fluctuations in price and electricity usage. Above p^* the stock of electricity is exhausted.

Figure 2: Stylized wholesale electricity market with elastic demand, storage and no network constraints



A reason existing markets have functioned despite the absence of an elastic demand curve is scarcity pricing. If firms are to supply energy at the marginal cost of production and prices were set at the marginal cost of the marginal unit, then the highest marginal cost generator (often a gas peaker) would never be able to recover their capital costs. Therefore, when the demand on system resources exceeds the capacity of system resources, prices need to exceed the private marginal cost of the peaker for it to justify its investment (Borenstein, 2000). In a market with sufficient demand elasticity, the willingness to pay for energy sets this scarcity price. To the extent wholesale demand continues to be relatively inelastic, administered scarcity pricing mechanisms are employed as proxies for the willingness to pay.[7]

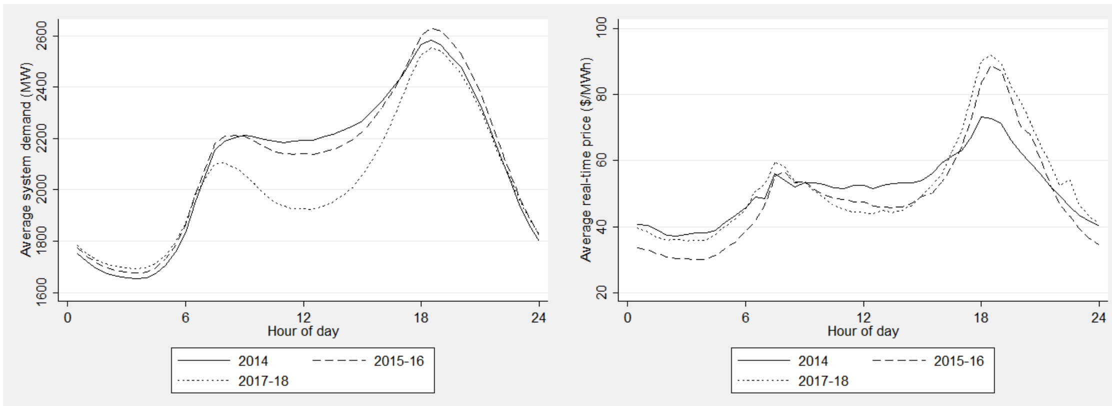
[7]Hogan (2005), Hogan (2013) and Hogan (2017) have described solutions that set scarcity pricing administratively as a function of the Value of Lost Load (VOLL) and the increasing probability of a loss-of-load event (Loss of Load Probability or LOLP) as the combined demand for energy and for system reserves begins to exceed the available resources, with prices approaching VOLL as the LOLP approaches 1.0. The result is scarcity pricing at opportunity cost, being the price the system operator should be willing to pay to keep resources in reserve rather than release them to meet incremental demand for energy.

3.2 Market responses to VRE penetration seen to date

The *merit-order* impact of variable renewable energy penetration is well-identified and studied (Felder, 2011; Simshauser, 2018). In a simplified, constraint-free network, the addition of a small amount of zero marginal cost energy is equivalent to a decrease in the demand for energy. Like in any other industry, all else being equal, spot prices will fall as some additional renewable output displaces output from the highest marginal cost source. Solar PV has a particularly strong self-cannibalizing effect (Hirth, 2013) – adding more solar depresses prices in the daylight production hours for solar generators. Increasing solar generator output has been documented to correspond with depressed prices in the daylight hours but also higher prices at sunset in California and Western Australia (Bushnell and Novan, 2018; Jha and Leslie, 2019). The prices that correspond to these changing system demand patterns (net of solar output, known as the "duck curve") reflect the low demand / high supply conditions in the middle of the day, but also the increased requirements for generators to start-up and ramp production to meet the evening peak demand as output from solar sources diminishes with sunlight (Figure 3).

Beyond these almost mechanical market responses to incremental VRE additions are dynamic impacts and ultimately a change in the composition of technologies that enter and exit the market. Simshauser (2018) argues that the focus on merit order effects with respect to VRE penetration is not a complete analysis – adding any supply suppresses prices in the short-run but any subsequent removal of supply raises prices. Short-run merit order effects from VRE penetration will be accompanied by long-run price rises as some other market participants respond by exiting the market. For example, less flexible base load technologies (coal-fired and combined-cycle gas turbines) have seen increased exit or reduced output in California and Western Australia, with output from more flexible sources (open-cycle gas turbines, hydro, and storage) increasing.

Figure 3: Hour-of-day dynamics in the Western Australian wholesale electricity market: 2014-2018



(a) Average net load by hour-of-day (b) Average real-time price by hour-of-day

Source: Jha and Leslie (2019). System demand has depressed in the middle of the day in recent years, corresponding to growth in rooftop solar adoption. Wholesale prices have fallen in the middle of day, but prices in the evening have increased.

Finally, outside of impacts on wholesale energy spot markets, increasing VRE penetration (and battery penetration) has been observed to change dynamics in frequency control and ancillary service (FCAS) markets, with the performance and market impacts from battery operators in South Australia being well documented in industry reports (Aurecon, 2018). Further, Australian policy makers are more focused on managing system security than reliability in the face of rapid VRE developments, stating “the more immediate worry is maintaining security” (Energy Security Board, 2020, p.8). The Australian market operator has been using off-market interventions to maintain system security at an increasing rate (Australian Energy Market Commission, 2019) and has been delaying connections or imposing output limits on new VRE sources as it imposes “do no harm” tests for new connections (Australian Energy Market Operator, 2020).

4 Price volatility: An essential feature of an efficient, green market

Wind and sunlight levels change across time and space. The unpredictable component of their intermittency raises a challenge, how can the market reliably source and deliver energy without outside interventions to install additional, dispatchable capacity? An efficient market with high VRE penetration must provide incentives for investors to invest in generation technologies that are able to complement the intermittency of VRE and/or give consumers the ability to respond and shift their power use during the day and storage operators to shift supply through time. It will be price variation, and therefore volatility, that can generate these signals. Rather than damaging the financial viability of markets with VRE penetration, volatility will play an important role in ensuring efficiency in the short run and in generating rents and incentivizing market risk management undertakings for long-run investments.

This section emphasizes the arguments for time-variation in prices, with Section 5.1 discussing the argument for prices to vary over space.

4.1 Short-run operational efficiency

As VRE penetration and spot-price volatility increases, allowing end-users to face prices that vary with time based on changing spot-market prices (either full real-time pricing or, where appropriate, some form of time-of-use price structure) will create incentives for end-users to shift demand in response to price. Industrial, commercial, and residential consumers can respond to price signals in two primary ways: first, by installing interval meters that can monitor usage in real time and technology to adjust equipment and appliance usage (through automatic response technologies) and second, by investing in storage technologies that can buy power when it is cheap and sell it back onto the grid when it is more expensive. It is important to recognize that consumers need not necessarily always pay the real-time price: If the monitoring and response technologies are installed, consumers can enter into hedging contracts with retailers that can be designed to effectively mitigate the risk they face (see Wolak (2019b) Section 4 for more details).

By exposing end-users in appropriate ways to the variability in spot prices, end-users also stand to profit from arbitrage opportunities by using storage. Storage offers an additional source of flexible demand, since consumers or commercial storage providers can buy power during periods of otherwise low demand, and storage can also act as a source of supply as power can be supplied during periods of high demand and low supply. If consumers face time-varying price signals, the average profits generated from storage (even if provided commercially) will reflect the willingness of consumers to shift power through time or reduce volatility.

We point out that volatility in *equilibrium* prices is not necessarily always increasing in VRE penetration. In the long run, it is possible that storage adoption or demand elasticity might develop such that volatility decreases. The equilibrium outcome will depend on the price of storage technology, the willingness of consumers to shift power through time etc. In fact, as Krishnamurthy et al. (2020) show, markets with higher supply variance may actually lead to investments in storage and other technologies for shifting demand that ultimately reduce price volatility.

4.2 Long-run investment efficiency

We discussed in Section 3.1 that VRE and storage dominated markets should result in a positive average spot price. This positive price can generate the incentives for investment in long-run investment in both generation and storage capacity. Krishnamurthy et al. (2020)

provide a formal proof and show that this level of investment is socially optimal; intuitively, the investment market is efficient here since the average expected spot price (benefit or profit to generators and speculators) equals the long-run marginal cost of investment in generation or storage capacity. Any lower (or higher) capacity will increase (decrease) the average spot price and hence investment incentives by pushing the x_t line and the blue line supply curve to the left (right) in figure 1. Moreover, Krishnamurthy et al. (2020) make the point that while additional investment in storage capacity can always reduce market volatility, at the efficient market outcome, the marginal benefit of reduced volatility to consumers will equal the cost of increasing storage capacity on the margin.

5 Key missing price signals and market design elements for the efficient development of VRE and storage in Australia's zonal, energy-only National Electricity Market

5.1 Network constraints

Markets can provide opportunities for private gain without social benefit if the market mechanisms that determine prices and allocations do not match the physical constraints of the system (Hogan, 1999; Harvey and Hogan, 2000a; Cramton, 2017; Wolak, 2019a). Empirical examinations of the efficiency gains from transitioning to nodal markets that align the market mechanism with physical constraints can be found in Wolak (2011); Green (2007); Zarnikau et al. (2014); Graf et al. (2020). Nodal markets have operated in the major US markets for many years, and the local market power mitigation mechanisms that have been developed in these markets can provide a useful template.[8]

[8]Resistance to nodal market designs can come from the belief that they allow for the abuse of local market power. However, ex-ante local market power mitigation mechanisms and ex-post detection mechanisms have effectively been developed (see, for example, Economics (2018) and The Brattle Group (2018)). Harvey and

Katzen and Leslie (2020) demonstrate that Australia's zonal market design is increasingly mispricing output from wind generators that have situated in similar locations. They make a case that having the prices participants face deviate from their impact on total system costs encourages additional, highly correlated, VRE to be built in the same constrained locations. Locational marginal pricing would dampen the incentives to build the same technologies at the same locations in constrained areas of the network. In turn, it would encourage the development of complementary solutions (such as batteries, synchronous sources, energy efficiency, or flexible demand technologies) that relieve network constraints and would allow a more efficient investment mix. In Australia's case, zonal prices that do not reflect these constraints could be contributing to many of the grid-connection delays being experienced by many new VRE investments, along with the infrastructure upgrades (such as synchronous condensers) required in areas of the network that has encountered a rapid penetration of VRE sources.[9]

5.2 Dynamic costs and scheduling

Supply and demand for energy can depend on past actions. Many electricity generating technologies have non-linear and dynamic cost structures, particularly thermal plants with start-up, ramping and minimum operating load fuel costs that can greatly differ to the marginal cost of operating near their capacity. Further, demand is usually more elastic at longer intervals (for example buildings can be pre-cooled/heated or the timing of operations shifted). The economic value of flexibility is increasing with VRE penetration, and an

Hogan (2000a) and Harvey and Hogan (2000b) provide arguments for why local market power issues in nodal markets would continue to exist (and may be exacerbated) under a zonal market design. Administrative scarcity pricing mechanisms such as those referred to in Section 3.1 have served the dual purposes in nodal markets of ensuring scarcity pricing while also affording system operators and regulators a means of ensuring scarcity pricing reflects legitimate scarcity and not the abuse of market power.

[9] See Energy Security Board (2020) for an overview of some of the off-market responses to VRE penetration being undertaken, and Australian Energy Market Operator (2020) for an overview of some connection delay issues.

efficient market design will allow participants to capture the economic value they create.

The National Electricity Market (NEM) operates separate, sequential auctions for each 5 minute dispatch interval. Although the NEM allows some plant-level technical constraints (such as maximum ramp rates) to be bid into the market, dynamic costs are not explicitly entered. Combinatorial auctions such as day-ahead markets can allow for participants to enter contingent bids (for example, requiring the sum of their spot revenues to exceed a daily revenue requirement to ensure they recover their start-up costs), for storage owners to bid/offer contingent on their charge level, or for more practical and effective demand-side participation. The gains from using day-ahead markets to improve scheduling of generators and loads could increase with greater VRE penetration (Cramton (2017) and Wolak (2019a) discuss the merits of multi-settlement markets). For example, day-ahead markets can accommodate an efficient holding out of reserves with ramping capabilities (reserves are also not currently priced and co-optimized via the market mechanism), which will become increasingly relevant in markets exhibiting a "duck curve" (Figure 3a). Multi-settlement markets can also provide profit motives for more accurate system forecasts via virtual bidding by financial participants, where there is evidence from California that this behavior can improve scheduling and system efficiency (Jha and Wolak, 2019).

5.3 Long horizon forward prices

The NEM has one of the highest bid caps in the world at \$14,700/MWh (≈ USD\$10,000) in 2019/20. This high bid cap, plus the recently adopted Retailer Reliability Obligation (RRO) are the pillars of the resource adequacy mechanisms in Australia. There is no direct 'market' for capacity, however the RRO has the ability to trigger both forward contract quantity requirements for retailers and ultimately the building of additional capacity when retail forward contracts are deemed insufficient to cover the market operator's reliability forecast (Energy Security Board, 2019).

The ability to receive prices greatly exceeding the private marginal costs of generators in scarcity conditions can be sufficient for investment in generation and demand-side assets. However, as discussed in Simshauser (2018) and Nelson and Orton (2016), the NEM has low levels of contract liquidity beyond 3 years, which may not be sufficient to support needed investment in the current Australian market context. As the complementary technologies to VRE are less likely to have base load output profiles, there is likely to be less demand for fixed-quantity swap contracts and more demand for option-style contracts that cover retailers in times of scarcity.

Although some jurisdictions around the world operate capacity markets, they are often accompanied by bidding caps that are orders of magnitude lower than the NEM.[10] Where spot prices are not explicitly capped, the incentives for and lack of constraints on over-procurement in capacity markets can produce similar effects. Capacity markets provide payments based on the dependable capacity (not energy production) of a resource. There are concerns that imposing much more stringent caps on spot prices and the poor operating incentives inherent to many markets with capacity mechanisms can result in substantial inefficiencies (McRae and Wolak, 2019; Harvey et al., 2013). Further, a low bid cap will also undermine efforts to develop an active demand side of the market and consequently the efficient integration of large amounts of VRE.[11] If the NEM approach to long-run resource adequacy is deemed to need changing, a way to preserve appropriate performance and investment incentives while improving hedge liquidity out to longer horizons is to mandate

[10]The ISO-NE, PJM, NYISO and MISO all have capacity markets and in 2019, a market offer cap of $USD1000/MWh

[11]For example, at a $14,700/MWh market price, switching off a 1kW air conditioning unit for a half hour could save a retailer $7, whereas if the market price was capped is $1,000/MWh it would only save $0.50, providing much less surplus to split between retailer and customer if trying to develop consumer demand flexibility. Conversely, if prices are capped at $1,000/MWh, a demand-side solution costing, say, $1,500/MWh may be displaced by generation investment with a much higher long-run marginal cost that is socialized through a capacity market.

procurement levels and reporting of long run contract positions by retailers (Oren, 2005; Wolak, 2019b).[12]

5.4 Allocating losses and Transmission Use of System (TUoS) charges

Rules relating to the allocation of line losses and the recovery of capital investment costs can directly enter the short-run operating decisions and long-run investment decisions of market participants.

Efficient recovery of line losses entails dynamic locational marginal loss factors (Bohn et al., 1984). Currently, generating units in the NEM have a static loss factor calculated annually and applied to all their output for the following year. The rapid growth of VRE sources, many of which are located away from load centers, has seen cases of plummeting loss factors.[13] A dynamic treatment of loss factors provides better incentives for storage to locate near VRE sources and recharge when VRE are generating in high amounts, which will in turn lower line losses and improve the efficiency of the system.

Efficient network cost recovery is particularly important in VRE markets with storage. In the NEM, generators pay for costs associated with connecting to the network and market customers pay Transmission Use of System (TUoS) charges when they purchase electricity (Australian Energy Market Commission, 2018). Currently grid-scale storage is considered in the NEM as both a customer and a generator. This may disincentivize grid-scale storage relative to storage in conventional (i.e. not pumped) hydropower dams and behind the meter storage.[14] We note the Australian Energy Market Commission (2018) recommends

[12] Arguments for capacity markets generally are based on correcting issues associated by a low bid cap and the absence of real-time meters for all customers and retail competition (see Cramton and Stoft, 2005), neither of which apply to the majority of the NEM. Refer to Batlle and Rodilla (2010); Harvey et al. (2013); Hogan (2013); Bushnell et al. (2017); Hogan (2017) for discussions on long run resource adequacy mechanism options.

[13] See Australian Energy Market Commission (2020) for a comprehensive overview of recent issues regarding marginal loss factors and a rule review for their derivation.

[14] There are many considerations for evaluating distributed versus grid-scale storage which we abstract

that network pricing be revised, but at the date of writing a final determination has not been made.

6 Conclusion

Changing technology mixes will change market outcomes, but they do not change the fundamental economic principles behind market design. Market-clearing prices in such a market are not necessarily mostly zero even in an energy-only market, especially with grid scale storage, an active demand side of the market and scarcity pricing. However, increasing intermittent generator penetration increases the importance for adequately pricing scarcity and all network constraints and services. Such pricing is required to deliver investment incentives for the right technologies to locate at the right locations to efficiently maintain a stable and reliable electrical network.

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away from in this article. One relates to scale economies, where it may be that for bulk storage it is more cost-effective to have grid-scale storage, in the same way that rooftop solar is more costly than large scale solar (Schmalensee, 2015).

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