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Optimising VRE plant capacity in Renewable Energy Zones

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Abstract

Australia experienced significant growth in variable renewable energy (VRE) investment commitments during 2016-2021. A subset of projects experienced material entry frictions which stemmed from inadequate network hosting capacity. In this article we examine the development of Renewable Energy Zones (REZ) as a means by which to help guide forward market commitments and produce greater coordination between generation and transmission plant investments. Using an optimisation model comprising 1500MW of transmission network infrastructure, we explore various definitions of a 'fully subscribed REZ' given portfolio benefits associated with complementary wind and solar resources in Southern Queensland. We also examine the conditions by which various proponents would initially sponsor and fund a REZ. When maximising output forms the objective function, full subscription is achieved by developing ~3400MW of wind and solar in roughly equal proportions, accepting some curtailment is an economic result. Conversely, minimum cost is achieved at ~1800MW of VRE. And if maximising net cashflows forms the objective, VRE development is complicated by the dynamic nature of spot prices. Specifically, in the early stages of a REZ solar is preferred but as its market share rises and value of output falls, wind investments dominate holding technology costs constant.

Key words: Renewable Energy Zones, renewable generation, transmission investment.

JEL Classification: D25, D80, G32, L51, Q41.

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1. Introduction

Australia's National Electricity Market (NEM) commenced in 1998 and for most of the first two decades was a marvel of microeconomic reform. However, as with many of the world's major power markets there have been periods in which pricing outcomes have tested policymaker patience.

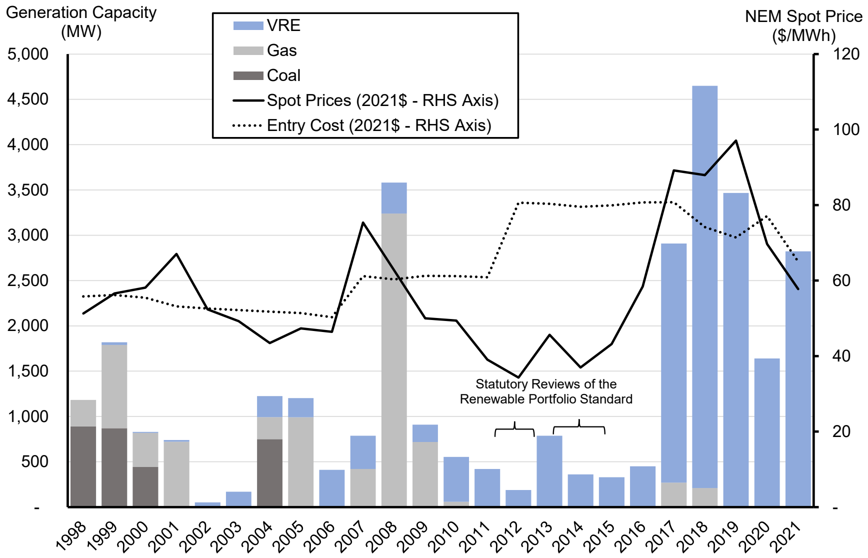
From a network pricing perspective, the 2007-2015 period represented one of these episodes. The cumulative value of NEM regulated network assets doubled from A$40.1 billion[1] to $83.3 billion, rising at a compound growth rate of 10% year-on-year. Over the same period, whilst initially on a growth trajectory, energy demand contracted from 192.5TWh to 180.4TWh (i.e. -0.8% year-on-year). Given revenue cap regulation, sharply rising assets and falling volumes had a predictable impact on network tariffs[2]. This historical context is important – NEM consumer groups are understandably wary of any contemporary proposals involving significant augmentations of the (consumer-funded) shared network.

Another such episode occurred during the NEM's *renewable investment supercycle,* which occurred over the period 2016-2021. Three distinct issues combined to produce sharply rising electricity prices in the wholesale market, viz. i). a disconnect between energy and climate policy (Simshauser and Tiernan, 2019; Rai and Nelson, 2020), ii). investment mistakes in retrospect in the adjacent market for natural gas and LNG (Billimoria et al., 2018; McConnell and Sandiford, 2020), and iii). disorderly (i.e. unforecasted) divestment and simultaneous exit of multiple coal plants (Nelson et al., 2018; Dodd and Nelson, 2019). A wholesale electricity market crisis ensued with the start being formally marked by a black system event in the NEM's South Australian region in September 2016. Spot prices surged, rising as they did from historic annual averages of A$50/MWh to ~$100 at their peak (Fig.1, RHS-Axis).

With spot and forward prices surging to historic highs, the market responded with a pronounced investment supercycle comprising mostly utility-scale solar and wind variable renewable energy (VRE). From 2016-2021, more than $26.5 billion of VRE plant commitments were made across 135 separate power projects totalling 16,000MW (Fig.1).[3] This is not unique. As Engelhorn & Müsgens (2021, p1) explain, VRE investment is a *'global megatrend'*.

[1] At the time of writing, A$1.00 = US$0.73, £0.53 and €0.62.
[2] Under this form of regulation, network businesses are free to set prices but cannot exceed the annual revenue cap. For an analysis of the policy conditions which led to these results, see Mountain and Littlechild, (2010), Nepal, Menezes and Jamasb (2014) and Simshauser and Akimov (2019).
[3] To put the 135 project commitments into context, in the previous 17-year window (i.e. from NEM start in 1998 to 2015) only 94 power project commitments were made.

Figure 1: NEM spot prices and VRE investments (1998-2021[4])



Sources: ESAA, Company Reports, BNEF, AEMO.

While a majority of VRE projects entered successfully, approximately 20%[5] did not. At the height of the supercycle, the adversely affected subset of VRE generators faced i). lengthy network connection delays, and in some instances, ii). sizeable post-entry network remediation costs due to rapidly deteriorating *system strength*. These projects also experienced iii). acute production constraints during the period of which system strength was remediated. Others still faced iv). plunging Marginal Loss Factors (i.e. the NEM's locational multiplier on spot prices) in the post-entry environment. A small number of projects experienced all four entry frictions, leading to non-trivial asset write-downs.[6] To be sure, plunging Marginal Loss Factors and system strength-induced costs merely represented the physics of the power system – but for affected developers, they presented as entry frictions.

VRE entry frictions and asset write-downs created a divisive debate over the durability of the NEM's multi-zonal, energy-only market design including proposals to variously alter Marginal Loss Factor calculations, introduce capacity mechanisms and shift from multi-zonal prices with MLF multipliers to nodal pricing, to better coordinate generation and transmission investment. Debates were unhelpful because problems and proposed remedies were disconnected. Entry frictions were caused by cyclical investment 'boom' conditions (i.e. the supercycle), asymmetric information and inadequate network hosting capacity. And the supercycle itself was driven by climate change *policy discontinuity* in prior periods – creating investment cliff-edges, disorderly coal exit and a lack of transparency under conditions of simultaneous investment commitment (see Nelson, et al., 2018; Dodd and Nelson, 2019; Rai and Nelson, 2020; Simshauser & Gilmore, 2021).

Among the central problems[7] now facing the NEM is an ongoing lack of VRE *network hosting capacity* and the complexity of replacing large exiting coal generators with dozens of distributed VRE generators. Axiomatically, a greater level of coordination and transparency seems desirable. Aravena and Papavasiliou (2017) explain the problem succinctly – VRE entry induces spatial and temporal coordination requirements.

[4] The Australian financial year ends 30 June.
[5] For an analysis of the various entrant categories and their entry frictions, see Simshauser & Gilmore (2021).
[6] Such costs were borne by investors, not consumers, which has been a central and enduring feature of the NEM design.
[7] The most pressing problem facing the NEM has been the requirement to bolster system security services (i.e. fast frequency response, ahead unit commitment for system strength, operating reserves and so on). For a detailed discussion, see Simshauser & Gilmore (2021).

Although the NEM has a zonal market design, investment locational signals are surprisingly strong by international standards as Eicke et al,.(2020) demonstrate (see also Simshauser, 2021). The NEM's five region / zonal prices reflect inter-regional transmission congestion. Locational price differentials are further amplified via Marginal Loss Factor (MLF[8]) multipliers, assigned to each of the ~1400 bulk supply points throughout the NEM. Collectively, zonal spot prices and locational MLF multipliers can (and do) produce average annual revenue differentials of as much as $35+/MWh, specifically, by up to $10/MWh across zones and as much as $25+/MWh across bulk supply points within a zone. Marginal improvements to locational signals will contribute little to solving the problem of inadequate network hosting capacity. Ultimately, network augmentation is both required and feasible.

NEM transmission planning is undertaken at the regional (i.e. zonal) level by incumbent transmission network utilities.[9] With the exception of shallow generator connection costs, regulated transmission charges associated with the shared network (i.e. the Regulatory Asset Base) are allocated entirely to consumers. Consequently, any consumer-funded augmentation of the Regulatory Asset Base must first pass a 'Regulatory Investment Test'. The regulatory test comprises a narrow definition of 'benefit'[10] and in practical terms means transmission augmentation is typically limited to addressing looming reliability constraints (viz. due to changing load patterns, or aged equipment). Adding complexity to the present task, given the politically divisive nature of climate change policy in Australia, there is currently no 'decarbonisation' limb to the Regulatory Investment Test for network augmentation. Conversely, market participants facing their own ESG commitments, and VRE developers, are seeking to move much faster than policy and regulatory processes currently permit.

One NEM-wide policy response with promising prospects for dealing with coal divestment and VRE entry are *Renewable Energy Zones* (REZ) at the transmission network level. REZ's are defined as regional areas within the NEM characterised by good wind and solar resources which currently have inadequate (or an absence of) transmission network infrastructure. REZ's are a means by which to develop much needed VRE network hosting capacity *at scale* with the underlying intention being to connect multiple parties that would otherwise act independently, thereby avoiding duplication and optimising scarce network resources.

REZ's are more than a theoretical concept. Sub-national governments in each of the NEM's three dominant regions (Queensland, New South Wales, Victoria) have advanced plans but establishment is *not* straight forward given the basic investment thesis is Pozo et al.'s (2013) *build it and they will come*. Key questions that logically follow are what mix of intermittent wind and solar plant capacity represents 'full subscription' of a REZ? And furthermore, *who pays* for scale-efficient, but initially under-utilised REZ network capacity? Given the experience of NEM electricity consumers over the period 2007-2015 outlined above, welfare groups are rightfully wary of transmission investment proposals which are automatically added to the Regulatory Asset Base. After all, it is the unsuspecting end-use consumer who bears the cost and consequence of planning failure and under-utilisation of any regulated network asset.

8 In the NEM, each of the ~1400 bulk supply points are ascribed a forward-looking Marginal Loss Factor or MLF based on projected network losses across the power system for each year ahead. MLFs are effectively a price/quantity multiplier (i.e. revenue = MWh x MLF x Spot Price). Details of the methodology and the set of current and historic MLFs for each generator and load are available at https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/market-operations/loss-factors-and-regional-boundaries.

9 NEM-wide planning is undertaken by the Market Operator through their biennial Integrated System Plan.

10 Under NEM Rules, the definition of benefit is limited to 'resource costs' (and does not incorporate any explicit or shadow value of CO_2 emissions).

If a REZ was to be developed as a consumer-funded asset and form part of the Regulatory Asset Base, then little more need be said beyond flagging risks associated with planning error and non-transient asset under-utilisation. In contrast, our specific interest is:

i. how generator-funded REZ transmission capacity is best utilised through various combinations of wind and solar PV, and

ii. under what conditions various proponents (i.e. VRE generators, transmission planner, government/taxpayer) are likely to underwrite such a (non-regulated) REZ during any period of asset underutilisation (*cf.* a default consumer-funded regulated network solution).

In this article, we model a radial REZ with a thermal rating of 1500MW. We optimise VRE plant capacity under varying objective functions including minimising overall unit costs, maximising output (PPA seller lens), and maximising net cashflows (PPA buyer lens). Our modelling produces useful insights. Minimising the combined unit cost of VRE plant and REZ transmission infrastructure was achieved at 1800MW of wind and – some 300MW above the thermal limit of the REZ radial transmission line. If maximising output forms the objective function (i.e. via endless PPA buyer capacity), then capacity additions could comprise more than double REZ thermal limits. Maximising net cashflows produced a rich variation in results – driven by the earned value of plant in the spot market (i.e. PPA buyer lens).

The incentives facing PPA sellers (i.e. maximise output) and PPA buyers (i.e. maximise net cashflows) are quite different due to their respective risk exposures, and the relative pattern of spot prices can bias a predominance of solar over wind, and vice versa. We also find a clear case for connecting multiple VRE plants with modest levels of production curtailment. Finally, the counterparty most likely to house the risk of transient REZ underutilisation runs counter to the inherent risk appetite of VRE generators, transmission planners and government, respectively.

This article is structured as follows. In Section 2 we review relevant literature. Section 3 outlines REZ pricing principles. Section 4 introduces our data and models. Section 5 examines model results. Policy implications and concluding remarks follow.

2. Review of Literature

The basic setup of energy markets following restructuring in the 1990s meant the historic co-optimisation of generation and transmission investment was no longer possible – generation investments would be driven by forward prices with transmission network utilities performing a *responsive role* (Sauma and Oren, 2006; Torre, Conejo and Contreras, 2008; van der Weijde and Hobbs, 2011; Wagner, 2019). This did not prove problematic at the time for two reasons. First, when restructured energy markets commenced in the 1990s power systems were typically *overcapitalised* with little need of vertical coordination (see for example Hoecker, 1987; Joskow, 1987; Kellow, 1996; Newbery and Pollitt, 1997). Second, the likelihood of adverse generation location decisions or inadequate coordination between generation and transmission investment was implicitly regulated by comparatively slow rates of entry, and (project financing-induced) due diligence processes of sophisticated utility generation investors with extensive knowledge of the local network topology (Nelson and Simshauser, 2013). In this environment, transmission network augmentations were frequently dominated by reliability considerations.[11]

[11] This was in spite of the potential for small transmission investments to result in surprisingly large competition benefits (Borenstein, Bushnell and Stoft, 2000).

The 2020s present as a very different environment to the 1990s. Any over-capitalisation has typically long been utilised, and efforts to decarbonise power systems has created a different dynamic for the coordination of generation and transmission investment. Multiple jurisdictions (e.g. US, Great Britain, Europe, Australia) have experienced material changes in the generation plant stock with VRE entry (Joos and Staffell, 2018; Wagner, 2019; Nelson, 2020; Bushnell and Novan, 2021) and this has significant implications for transmission networks. Unlike the slow and grinding pace of thermal plant development and entry, VRE entry can (and in the case of the NEM, does) occur at rapid pace and in multiple locations simultaneously.

A growing body of literature highlights that a changing plant mix associated with decarbonisation efforts inevitably drives material increases in the demand for costly transmission infrastructure, associated ancillary services and greater intervention by Market Operators (see variously Neuhoff *et al.*, 2013; Bird *et al.*, 2016; Neuhoff et al., 2016; Bertsch *et al.*, 2017; Joos and Staffell, 2018; Ambrosius *et al.*, 2019; Wagner, 2019; Heptonstall and Gross, 2020; Pollitt and Anaya, 2021).

2.1 The role of policy in amplifying coordination problems

Policies underpinning rapid VRE deployment has served to amplify coordination problems inherent in restructured energy markets (Alayo, Rider and Contreras, 2017; Wagner, 2019; Simshauser, 2021). It is well established in the literature that policy design has adversely impacted locational decisions in many jurisdictions (see Grothe and Müsgens, 2013; Schmidt *et al.*, 2013; Pechan, 2017; Engelhorn and Müsgens, 2021).

In Germany, VRE was priority dispatched and granted imputed revenues in the presence of network congestion, while the existing market design has little in the way of locational signals (see Oggioni et al, 2014; Eicke et al, 2020; Höfer and Madlener, 2021). Pechan (2017) shows how fixed price contracts in Germany drive VRE investments to congest around the best resource sites, whereas stronger locational signals and VRE plant exposed to spot markets would otherwise produce spatial diversity and lower generation curtailment, because in this latter instance the *market value* of output (Joskow, 2011; Hirth, 2013) drives location decision making (Peter and Wagner, 2021). Policy settings can, and evidently does, work against optimal siting decisions by excluding or overriding explicit or implicit locational signals that otherwise exist in energy markets.

In Australia, renewable policy discontinuity is known to have driven cyclical boom-bust investment conditions which adversely impacted coordination and VRE plant investment location decisions. During the NEM's 135 project *supercycle*, coordination problems emerged including a need to remediate system strength ex-post in certain locations[12], with non-trivial VRE curtailment during the intervening period, sharp adverse movements in MLFs (particularly with solar PV) and connection lags (Simshauser & Gilmore 2021).

Sub-national governments amplified poor location decisions and NEM coordination problems via the inherent design of reverse CfD auctions. Among the more prominent examples was *Victoria's* 2017 reverse auction designed to underwrite 650MW of VRE entry.[13] Winning bidders were offered 15-year government-backed CfDs, the ideal contract structure for project financed VRE. Government documentation reveals *bidder price* (i.e. levelized cost) was the driving variable (VicGov, 2017b). Once lowest bids were

[12] As one Reviewer noted, this was especially the case in South Australia vis-à-vis failures in co-ordination of generator retirement and network augmentation.

[13] Another was the *Australian Capital Territory's* (ACT) reverse auction which led to multiple plants being built in the South Australian region (i.e. VRE supply added, VRE output effectively speculatively traded in SA without load). This has since led to non-trivial retail tariff increases in the ACT with the CfDs currently out-of-the-money (and recovery occurring by increasing the ACT regulated network tariff). See Brown (2021) at https://www.canberratimes.com.au/story/7197512/evoenergy-wants-a-big-rise-in-electricity-prices-to-cover-acts-renewables-targets/

assembled, VRE project location had a weighting of just 10% (VicGov, 2017b).[14] Proponents only needed to have submitted a connection application to the relevant network utility (VicGov, 2017c) – no evidence of the feasibility of plant location was required.[15]

The 650MW auction led to more than 1,000MW of VRE capacity being developed (i.e. proponents built above CfD-contract capacity) with various successful projects amplifying existing locational constraints. The Market Operator (AEMO) and Victorian transmission network utility (Ausnet) flagged potential problems on multiple occasions as far back as 2017 – to no avail.[16] A central lesson from the auction process was the absence of locational considerations (VicGov, 2020).

Badly sited generators can result in inefficient levels of congestion and curtailment, and give rise to negative externalities in future transmission planning (Schmidt *et al.*, 2013; Bird *et al.*, 2016; Alayo et al. 2017; Bertsch *et al.*, 2017; Pechan, 2017). Greater coordination of VRE generation and transmission investment should therefore be of unquestionable interest to policymakers, consumer groups and investors alike (van der Weijde and Hobbs, 2012; Munoz et al., 2017; Pechan, 2017; AEMC, 2019; Ambrosius et al., 2019; Eicke et al., 2020).

2.2 NEM design: multi-zonal vs nodal

Australia's market bodies (i.e. Energy Security Board, Energy Market Commission, Energy Regulator) responded to the coordination problems by focusing on a switch from a multi-zonal market design with MLF multipliers, to nodal pricing with an expectation that this will reduce the incidence of network congestion, and better coordinate network and VRE investment commitments through more acute locational signals. Such a proposal appears intuitive, after all, zonal markets are purposefully designed to enlarge the inherent size of locational spot markets by ignoring (intra-regional) constraints and network congestion (Ruderer and Zöttl 2018).

There should be no doubt the nodal market design envisaged by Schweppe *et al.*, (1988) will outperform multi-zonal markets from a dispatch efficiency perspective (Bjørndal and Jørnsten, 2001; Joskow, 2008; van der Weijde and Hobbs, 2011; Neuhoff *et al.*, 2013; Holmberg and Lazarczyk, 2015). The principal benefit of nodal pricing is generally considered to be dispatch efficiency given varying unit fuel costs (Joskow, 2008; Eicke et al., 2020). Studies within the literature consistently confirm this to be the case. Analysis of Great Britain by Green (2007) shows a shift from zonal to nodal pricing would improve dispatch efficiency by 1.3%. Analysis of Central Western Europe by Oggioni and Smeers (2012) and Oggioni et al (2014) find welfare gains from nodal design of ~0.001% in scenarios where wind generation is *not* priority dispatched, and substantially higher where wind is priority dispatched. Leuthold et al. (2008) find welfare gains of 0.8% in their analysis of the German market. Neuhoff *et al.*, (2013) analyse zonal vs nodal pricing in the EU and find efficiency gains of 1.1% - 3.6%, while Abrell and Kunz (2015) find a 0.6% improvement in dispatch efficiency from a nodal design in Germany. Aravena and Papavasiliou (2017) similarly find efficiency gains of ~2.8% from a nodal design. Analyses of the change to a nodal design in Texas find gains of 2-3.6% (see Zarnikau et al., 2014; Triolo and Wolak, 2021), though we note limited comparability to the NEM due to variances in system topology representation and redispatch processes inherent in these markets. Specifically, the NEM's dispatch algorithm comprises a representation of nodal

[14] Evaluation was clearly set out as follows: Best value for money measured by lowest bid prices, and five criteria as follows - 1). Commercial viability 25%, 2). Technical capability 25%, 3). State Economic Development 25%, 4). Community Engagement & Benefits 15%, and 5). Impact on existing electrical network infrastructure 10%. See Victorian Renewable Energy Target 2017 Auction – Industry Information Session slides, Department of Environment, Land, Water and Planning, Victoria State Government.
[15] Documentation was clear that "applications do not necessarily have to have been approved by the network service provider or AEMO to be eligible to bid into the auction" (VicGov, 2017a).
[16] See Parkinson (2020) at RenewEconomy (wpengine.com)

constraints, and generator offers are adjusted by locational Marginal Loss Factors. Consequently NEM zonal prices do reflect least cost offers whilst representing the transmission system. In other markets (such as 'zonal ERCOT') initial dispatch ignores transmission. Nonetheless, recent quantitative modelling of Australia's NEM under existing zonal design have pointed to dispatch inefficiencies of $140-180 million or ~1.5%[17] per annum. In summary, the universal result of studies examining nodal pricing consistently reveals positive dispatch efficiencies.

However, commencing a reform with a nodal market design in the 1990s is a distinctly different decision to one aimed at changing a mature multi-zonal market after 20 years of investment commitments totalling more than $50 billion. Besides which, and as implied in Section 1, the out-workings of the NEM's 2016-2021 VRE supercycle are unlikely to have been avoided by an alternate market design. The problem of generation and transmission coordination in the NEM did not arise due to an inherent lack of locational signals.

As Eicke et el. (2020) demonstrate, NEM location signals are amongst the strongest of 12 of the worlds' major electricity markets once multi-zonal spot prices and the ~1400 site-specific MLF multipliers are accounted for. For example, the 2020 MLFs allocated to *a dozen simultaneous new entrant* solar PV projects in Central and North Queensland *in the post-entry environment* were in the range of 0.84 – 0.87, meaning the zonal price earned by these plants were adjusted downwards or penalised by 13-16%. As an aside, in the pre-entry environment (i.e. ~2016-2017) the same MLFs were ~1.00.[18] Readers familiar with VRE project development will appreciate just how significant such revenue impacts are on investment commitment decisions (i.e. an MLF change of 15%, which flows through to revenue, will likely be fatal for projects). Conversely, solar PV plants in Southern Queensland faced 2020 MLFs of 0.98 in the post-entry environment (i.e. zonal price adjusted downwards by only 2%). Ultimately, post-entry changes to MLFs *are forecastable* and have equivalent locational signalling as a nodal price vis-à-vis annual returns to equity. And given NEM convention is for forward contracts to be written against zonal spot prices (*cf.* VRE station gates), poorly located projects are *not* shielded from MLF movements by PPAs or CfDs.

What does emerge from closer inspection of the 2016-2021 supercycle was i). poor locational due diligence processes and subsequent investment failure by ~20% of (non-utility) equity investors under cyclical boom conditions with asymmetric information, and ii). a general lack of VRE network hosting capacity within the NEM's transmission network (Simshauser & Gilmore, 2021). Of these, the former requires no policy response whatsoever, and the latter will *not* be resolved by a change of market design.

While there is no doubt dispatch efficiency would be enhanced through nodal pricing, as far as we are aware, there is no real evidence to suggest nodal designs produce material gains in locational investment decision-making, or better coordinate transmission and generation investment. Congestion rents are known to fall within the range of 10-30% of augmentation costs (Eicke, Khanna and Hirth, 2020). Further, Brown et al.,(2020) analyse the change from zonal to nodal prices in Texas and find weak- to no- evidence of improved locational decision-making by entrants. Moreover, well-designed multi-zonal markets reflect transmission scarcities in a proximate way (Bjørndal and Jørnsten, 2008; Grimm *et al.*, 2016). Any shift to nodal pricing becomes still harder to justify as a first step to perceptions of coordination problems when dispatch efficiency benefits, typically in the

[17] Modelling work undertaken by NERA in 2020 on behalf of the Australian Energy Market Commission for their 'CoGaTI' project.

[18] Specifically, solar plants at Barcaldine, Clare, Claremont, Daydream, Hamilton, Haughton, Hayman, Lilyvale, Ross River, Rugby Run and Whitsunday located in Central & North Queensland all had 2020 (i.e. post-entry) MLFs between 0.84 and 0.87. The same MLFs in 2016 (i.e. pre-entry) were around or above 1.00, but in the post-entry environment a localised collapse of loss factors reflected the impact of excess entry in the area. Similar loss factors experience in regions like Alberta (AESO, 2020) point to the global relevance the network co-ordination problem under the energy transition.

range of 0.1-3.5% in the literature outlined above, would pale into insignificance to transaction costs associated with a mass 'market disruption event'[19,20]. Finally, the comparability of such studies should also note the impact of potential disparities between the network representation in zonal clearing mechanisms on dispatch efficiency improvements. In particular, a region such as ERCOT transitioned from economic merit order with limited network representation and corrective redispatch, to a nodal model (Brown et al., 2020), whereas NEM dispatch already impounds network constraints.

2.3 Transmission planning and Renewable Energy Zones

From a policy perspective, interim steps vis-à-vis locational guidance and network hosting capacity are available that do not involve fundamental market design changes. Numerous studies show transmission planners that guide market decisions on optimal locations given prevailing network hosting capacity can materially enhance welfare (Sauma and Oren, 2006; Tor et al, 2008; van der Weijde and Hobbs, 2012; Munoz et al., 2015; Alayo et al., 2017; Munoz *et al.*, 2017; Ambrosius *et al.*, 2019; Wagner, 2019). In the case of Germany Engelhorn and Müsgens (2021) find better coordination could have produced a 20% reduction in wind generation costs. And as one reviewer noted, other initiatives to enhance nodal connection capacity via (for example) digital mapping systems such as those in Great Britain and California can also be expected to improve location decision-making.

As noted at the outset, a novel policy response by Australia's sub-national governments has been the concept of REZs as a means by which to develop much needed VRE hosting capacity *at scale* (Simshauser, 2021). By definition, REZs send a strong signal regarding optimal location of new generation, noting investment commitment decisions are driven by *ex-ante* expectations of forward prices and locational signals, not ex-post outcomes (Hadush et al. 2011; Eicke et al. 2020). The case for non-regulated REZ's in the NEM is clear enough, but this leaves the question of *'who pays'*.

3. Who pays? REZ pricing principles for common user infrastructure

The availability of network capacity (or its *telegraphed development*) forms a determinative factor with regards to VRE investment commitment decisions (Brown et al., 2020). But not all parts of the available network represent optimal locations. The intention of a REZ is it represents one of many optimal locations within the power system footprint. Recall that the basic principle behind REZ is to promote co-ordinated development of network hosting capacity, at scale, in optimal locations, with pre-packaged system strength by transmission planners for VRE developers who would otherwise act independently. A fundamental principle is that REZ are purposefully designed to be *oversized* relative to foundation VRE generators, which raises the question of 'who pays' for expected transient excess capacity. Recall from Section 1 that the dominant network investment cost/risk allocation outcome in the NEM is that:

i. generators fund shallow connection and network cut-in costs (i.e. contracted network assets), and

ii. the consumer rate base funds shared network augmentation (i.e. the Regulatory Asset Base)[21].

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[19] If Australia's NEM was to change from multi-zonal plus MLFs to nodal prices, most contracts would break down because MLFs are fundamental to wholesale market transactions. This would therefore trigger the renegotiation of more than 100 Power Purchase Agreements (PPA) en-masse, and adversely impact $19bn of project and corporate finance underpinning Australian generators (see Simshauser & Gilmore, 2021). The system operator's initial estimate of system changes was $300m for their own IT network.

[20] See AEMC (2019) for example. In a more recent example, the 5-minute settlement rule change was thought to involve '$10s of millions' in system costs. Market participants have already spent over $400m and this excludes the costs of the market operator's system.

[21] The authors are aware of a small number of exceptions whereby generators have funded augmentation of the shared network.

In the analysis which follows, we assume that ultimately, REZ transmission infrastructure and associated charges are ultimately paid by participating VRE generators, not end-use consumers as is the case with regulated assets. But this leaves the question of who pays for idle REZ network capacity during the ramp-up period to 'full subscription' of the REZ (and separately, what 'full subscription of a REZ' actually means).

In a simplified (*albeit unrealistic*) scenario, a non-regulated REZ might involve the simultaneous contracting of multiple VRE generators for the full capacity of the new transmission infrastructure – with each VRE counterparty and transmission planner dependent upon the other in achieving financial close at a moment in time. In the real world, this is likely to be risky, time consuming, inefficient and constrain VRE growth below market potential. More likely, a REZ will involve new transmission network capacity that has been sensibly but sufficiently oversized to optimise economies of scale such that *later-in-time* VRE developers benefit from available uncontracted transmission capacity with future projects.

A foundation VRE generator that is small relative to total REZ capacity could not be expected to fund excess capacity in the presence of a competitive market as Section 5.2 subsequently reveals. Yet it may be possible for foundation VRE generator(s) to carry the REZ cost if entry is sufficiently large.

Transmission network utilities are typically assumed to be risk neutral. But parametric uncertainty regarding aggregate demand, construction costs, policy, long lead times and the consequences of irreversible investment commitment typically means transmission planners are in fact *highly risk averse* (Munoz *et al.*, 2017). In our subsequent analysis, we contemplate a *bounded risk seeking*[22] transmission planner under uncertainty, who seeks to guide the market with an objective function of maximising welfare through developing common-user infrastructure. The nature of how this might occur appears in Simshauser (2021) and so we do not propose to reproduce such analysis here. But to summarise briefly, the strategic objective of such a transmission planner would be to create a risk-adjusted contracted asset base (i.e. alongside its regulatory asset base) with pliable debt instruments used to defray *ramp-up period* risks.

A final source of funding beyond generators and transmission network utilities are sub-national governments (i.e. taxpayer-funded, rather than electricity consumers[23]). Government-funded REZs would achieve the desired purpose of facilitating further VRE growth, noting that there are natural limits to the availability and subsequent allocation of government balance sheet capacity, and thus cannot be relied upon for all circumstances.

In Australia, a non-regulated REZ is effected through designation as a Dedicated Network Asset, which allows NEM participants to control connection to non-regulated transmission assets via an regulator-approved third party access policy. User charges must be at least equal to the estimated avoided cost of providing access to the asset, but not more than the estimated cost of providing it on a standalone basis.[24] On this basis, the choice of structure for a non-regulated REZ can be based on an array of pricing principles, each ultimately aimed at allocating the risk of capacity under-utilisation and at what expected cost (i.e. ex-ante, risk-adjusted returns). Noting a spectrum of alternatives exists, we consider three alternatives.

[22] Risk appetite is bounded by the fact that NEM transmission networks typically have a capital stock of ~$8-10 billion, and the value at risk in the following exercise represents a small fraction of this.
[23] The key distinction here is that taxes raised through the Treasury (i.e. taxpayers) are derived from progressive sources, whereas raising taxes via the kWh (i.e. electricity consumers) is highly regressive.
[24] See in particular Chapter 5 of the National Electricity Rules, r 5.2A.8(b1)(3).

3.1 VRE generators opt to carry the risk

Here VRE generators with otherwise isolated renewable resources would contract the transmission planner to establish scale-efficient (i.e. oversized) REZ capacity, and as foundation users, the VRE generators carry the risk of under-utilisation. In a competitive market, the reason why VRE generators may opt to follow this path is that absent their interjection, their renewable resources may not otherwise appear in the optimal forward development path.

There are a number of ways that VRE generators can underwrite a REZ, the most likely of which is through higher transmission charges in early years until subsequent projects are committed. As our modelling results in Section 5.2 subsequently reveal, this option is most likely in scenarios where:

- Foundation VRE generator(s) utilise a dominant component of initial REZ capacity; and

- The same VRE generator(s) are capable of valuing optionality of any excess REZ capacity because, for example, they are able to expand foundation wind/solar projects through adjacent production stages.

Pricing principles would be largely informed by the competitive landscape of VRE project development and the availability (i.e. prospect) of securing future PPAs for adjacent production stages. Investors in greenfield projects can ascribe value to oversized REZ infrastructure when subsequent expansion stages exist with foundation VRE projects. In exchange for underwriting oversized scale-efficient capacity, VRE developers would seek to secure *first property rights* over remaining REZ capacity. The only policy matter that warrants consideration is the risk of under-utilised *REZ capacity hoarding*.[25]

3.2 Transmission planner carries the risk (*build it and they will come*)

This approach formed the basis of analysis in Simshauser (2021), where the transmission planner funds REZ network infrastructure on an unregulated basis and carries un-contracted (i.e. oversized) capacity, with initial charges to VRE generators flowing on the basis of a 'deemed' fully contracted asset. Consequently, transmission charges allocated to foundation VRE generators would be proportionate to their pro-rata use of the REZ – albeit noting 'fully contracted' requires careful definition as Sections 5.2-5.4 subsequently reveal.

For clarity, in practice foundation VRE transmission charges would be capped at their pro-rata rate and the transmission planner would recover residual exposures once additional VRE generators commit. Under such a model, risk-adjusted returns to the transmission planner would need to reflect the potential for any transient (and non-transient) under-utilisation.[26] There is also a risk of generation developer / transmission planner 'hold-up' vis-à-vis the treatment of foundation VRE plant and later-in-time VRE entrants. A need exists to balance marginal revenues of later-in-time connecting VRE entrants (given the transmission planner has sunk the capex), and the rights afforded to foundation VRE generators (i.e. most favoured nation clauses) who in their own way are critically important to underwriting the REZ. Such tensions require careful management in commercial constructs to ensure incremental revenues compensate development risks taken (*cf.* in a worst-case scenario, rebated to foundation VRE generators).

[25] Australia's Public Interest Advocacy Centre put forward a similar risk-sharing model (PIAC, 2019) albeit with some risk of a free rider problem (see AEMC, 2019b). This underscores the importance of granting *first rights* or some other financial mechanism to compensate foundation VRE generators for carrying the risk.

[26] Given the evident risks involved, it would be highly unusual for a REZ to enter a pre-feasibility stage (let alone reach financial close) without first identifying a suite of 'semi-mature' projects in the identified zone. With this backdrop, risk-adjusted returns would presumably reflect the transmission planner's view of expected marginal future VRE contracting, incorporating the quality of VRE development proponents and prospects of significant market-driven (i.e. commodity cycle) delays to investment commitment – again something we explore in detail in Section 5.4.

3.3 Government carries the risk

This presents as a logical extension to 3.2 in which government (i.e. taxpayer) funding *wraps* the investment risk of under-utilisation either permanently or on a time-limited basis until sufficient VRE generators commit. The transmission planner would establish the REZ with charges derived from a combination of foundation VRE generators and shadow transmission charges funded by government. Shadow charges would be referable to the oversized scale-efficient capacity. To summarise, the entire capacity of the transmission infrastructure is underwritten by the combination of foundation VRE generators and government, the latter being either permanent, or time-limited.

As new VRE generators connect and contract with the transmission planner, the shadow charges payable by government would be reduced. In practical terms, this option is most feasible where scale-efficient transmission infrastructure is significantly oversized relative to foundation VRE generator(s) capacity, or where some other regional development imperative exists.

4. REZ optimisation: conceptual overview, data and models

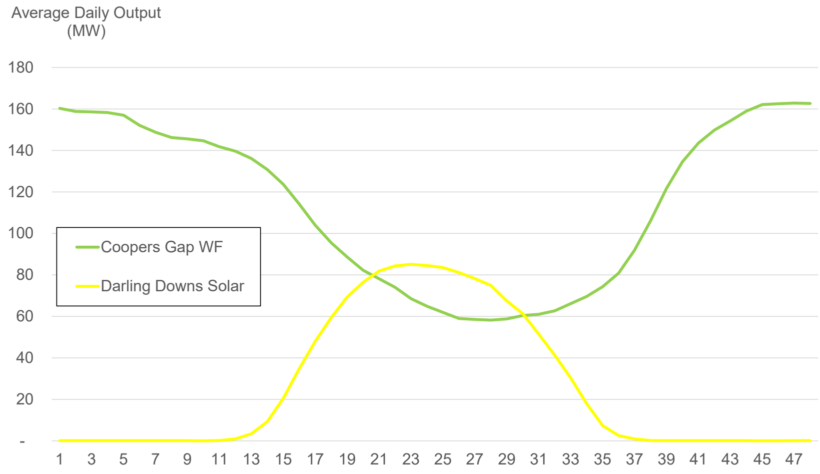
Rising VRE curtailment as renewable market shares expand within a power system is not, prima facie, evidence of inadequate coordination between generation and transmission investment. Nor will rising curtailment necessarily represent evidence of poor locational decision-making. For context, during the 1990s few baseload coal-fired generators operated at 100% of available productive capacity across every moment in time. Even well-timed and appropriately sized coal plant investments had capacity utilisations in the range of 70-90% of practical output in line with the diurnal pattern of power system demand and technical limits of the existing portfolio of plant.

The case of renewables is analogous. Due to mismatches between intermittency, the cost of storage and the relative pattern of power system demand, later-in-time VRE entrants are *unlikely* to produce at 100% of potential output. As Newbery (2021) explains, a 100MW wind farm with an average capacity factor of 33% will have a peak-to-average output ratio of 3:1 (i.e. 100MW maximum output, 33MW average output). A region's first wind farm can be expected to operate unconstrained. But as wind generation approaches significant market share, moments of substantial *potential* wind output will confront network congestion and wind generation curtailment. This is entirely predictable and acceptable. Indeed, the quantitative analysis that follows demonstrates a 1500MW radial REZ transmission connection will be optimally populated with more than 1500MW of VRE (nameplate) capacity – confirming moments of congestion and curtailment are inevitable and under our model conditions, constraints and objective function, welfare maximising.

4.1 Queensland wind and solar resources – portfolio effects

To understand the nature of a REZ and the optimal mix of plant within it, Figure 2 presents the simple daily average output from two existing VRE projects from the NEM's Queensland region, viz. a ~300MW wind and ~100MW solar PV plant. By way of brief background, the wind farm has a *potential* Annual Capacity Factor (ACF) of ~36% and the solar farm's potential ACF is ~28%. Notice from the simple daily average profiles that solar PV production peaks when wind production falls towards its production nadir. As an aside, the 30-minute (2020 year) correlation coefficient of production output of the two adjacent facilities was -0.32.

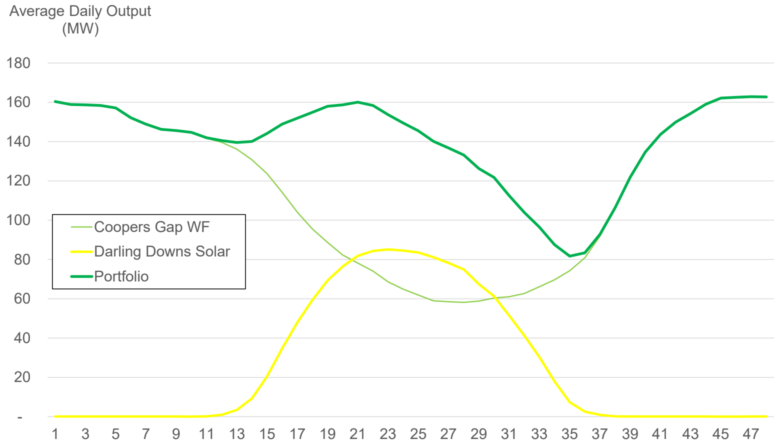
Figure 2: Southern Queensland 300MW Wind & 100MW Solar PV



Source: AMEO.

Figure 3 presents the daily average production profile as a combined wind/solar portfolio. While a notable production gap exists during periods 29-48 (i.e. 3pm-7pm), the combined technologies produce a better overall profile.

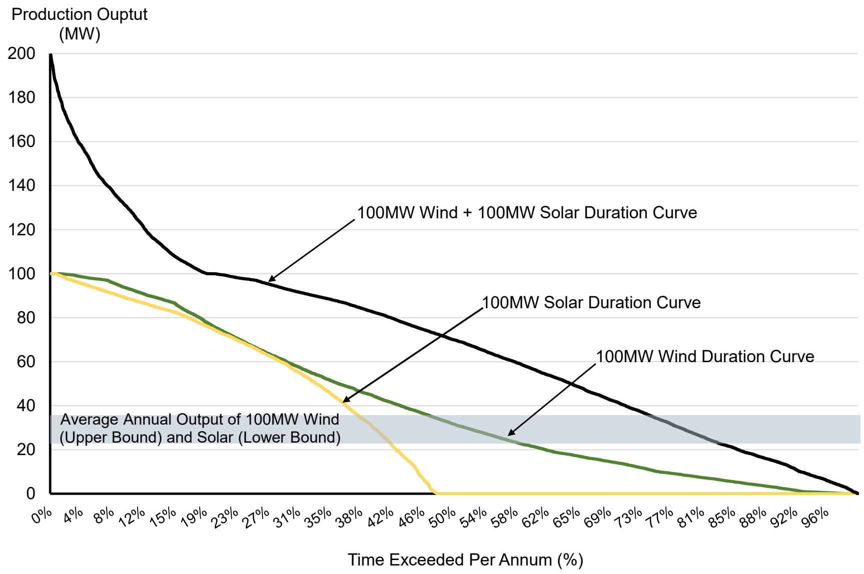
Figure 3: Wind + Solar Portfolio



4.2 Wind and solar data

Our analysis explores the optimal utilisation of a 1500MW REZ in Queensland's southern zone by abstracting locationally adjacent projections for wind and solar projects to those in Fig.2-3 via data from AEMO's Integrated System Plan database. Production duration curves (30-minute resolution) for the two resources individually, and as a portfolio, are illustrated in Figure 4.

Figure 4: Production duration curve for wind and solar resources



Source: AEMO.

In Figure 4, notice the solar PV plant operates for about 50% of the year, with output spanning 0-100MW (potential ACF of 30.0%). Wind output operates for ~95% of the year (potential ACF of 36.1%). The combined simultaneous output of the two plants is also plotted, and of special interest to our analysis are portfolio effects and the subsequent optimal deployment given scarce transmission resources.

Marginal production levels for each plant and plant portfolio are further analysed in Table 1. Table 1 seeks to find the minimum level of transmission capacity required for a 100MW wind farm with output not less than ~280GWh or 32% ACF (*cf.* potential ACF of 36.1%) and for a solar project of not less than ~195GWh or 22% ACF (*cf.* potential ACF of 30%). The basis for 32% and 22% ACF constraint, respectively, can be thought of as minimum viable (i.e. *bankable*) production output levels given a current renewable market share of ~20%.[27] The relevant results at these output levels have been highlighted at the 3rd and 5th columns of Table 1 and reveal that to meet this minimum output:

- 99MW of allocated REZ transmission capacity is required for wind, and
- 91MW of allocated REZ transmission capacity is required for solar.

But it is the 6th column of Table 1 that is of particular interest. It reveals that to achieve the same level of production output when deployed as a portfolio (i.e. 280GWh wind + 195GWh solar = 475GWh portfolio), only 140MW or 70% of allocated REZ transmission capacity is required compared to the simple sum of 190MW (i.e. 99MW + 91MW). Note also the relative utilisation of 140MW of combined transmission capacity is 39.3%, materially exceeding the individual ACFs of 32.4% and 22.3%, and their blended average of 27%.

[27] The point to note here is that as VRE increases in market share, the extent to which a project may face congestion and economic dispatch constraints can be expected to rise (see Newbery, 2021).

Table 1: Transmission capacity use of Wind, Solar vs. Wind+Solar Portfolio

Production Percentile	Allocated REZ Capacity (MW)	Wind Project ACF (%)	Allocated REZ Capacity (MW)	Solar Project ACF (%)	Allocated REZ Capacity (MW)	Wind+Solar REZ ACF (%)
100th	100	36.1%	100	30.0%	200	33.0%
99th	100	35.1%	99	29.0%	183	35.2%
98th	100	34.2%	98	28.0%	172	36.5%
97th	99	33.3%	97	27.0%	163	37.3%
96th	99	32.4%	95	26.0%	157	37.8%
95th	98	31.6%	94	25.1%	151	38.4%
94th	98	30.7%	93	24.2%	145	39.1%
93rd	97	29.8%	92	23.2%	140	39.3%
92nd	96	28.9%	91	22.3%	136	39.6%
91st	94	28.1%	89	21.4%	132	39.7%
90th	93	27.2%	88	20.5%	128	39.9%

Our subsequent analysis seeks to further analyse a 1500MW REZ through use of two sequential models, i). PF Model to derive initial plant cost estimates, and ii). REZ Optimisation Model, which allocates scarce transmission connection capacity subject to various user-specified constraints.

4.3 VRE Project Financing & Average Unit Costs

Our analysis of VRE unit costs relies on the assumptions set out in Tables 2 and 3, and our PF Model (Appendix I). Table 2 lists cost and technical parameters for wind and solar PV. Overnight capital costs of $2050/kW (wind) and $1200/kW (solar) reflect recent NEM median entry costs (see Simshauser & Gilmore, 2021). Potential ACFs of 36% and 30% for wind and solar respectively represent gross possible output per Figure 4. From this, adjustments must be made to derive estimates of practical output, including curtailment, auxiliary load and likely ascribed MLFs. Operations & Maintenance (O&M) costs have been drawn from industry reports. Finally, Ancillary Services costs[28] have been estimated at -5% of sales revenues.

Table 2: Plant cost assumptions

Variable Renewable Energy		Wind	Solar
Project Capacity	(MW)	250	200
Capex	($/kW)	2,050	1,200
Annual Capacity Factor	(%)	35.0%	28.0%
Expected Curtailment	(ppt)	1.5%	3.3%
Auxillary Load	(%)	1.0%	0.5%
Transmission Losses	(MLF)	0.970	0.960
Fixed O&M	($/MW/a)	20,000	20,000
Variable O&M	($/MWh)	5.00	0.00
Ancillary Services Costs	(% Rev)	-5.0%	-5.0%

The overwhelming majority of VRE plant in Australia's NEM are project financed (Nelson, 2020). Table 3 sets out our financing assumptions used in the PF Model.[29] The sizing of project facilities is consistent with current market metrics, viz. Debt Service Cover Ratio (DSCR) of 1.25x and is the key binding parameter. At 1.25x, it is implicitly assumed that plant have a long-dated PPA written by an investment-grade counterparty. Debt pricing is

[28] The National Electricity Market has 4 x 2 Frequency Control Ancillary Services (FCAS) spot markets, viz. for Frequency Regulation, along with 6 second, 60 second and 5 minute Frequency Contingency. That is, there are 4 Frequency Services, with spot markets for each of i). raise and ii). lower duties. The basis of recovery for Regulation FCAS is 'causer pays'. In practice, to the extent that a solar PV or Wind plant deviate from the linear trajectory of their 5-minute dispatch target, they will accumulate an FCAS Regulation liability. In our experience, at different points in the electricity market business cycle FCAS liabilities vary from trivial (i.e. $200,000 per annum for a 280MW wind farm) to substantial ($5 million per annum).

[29] While NEM power project financings have historically comprised various combinations of 5- and 12-year debt facilities, it is more common now for projects to secure single 5- or 7-year facilities due to comparative pricing of medium (*cf.* long-dated) money. In this instance, we have opted to model a blended 5- and 7-year facility with weightings of 35/65.

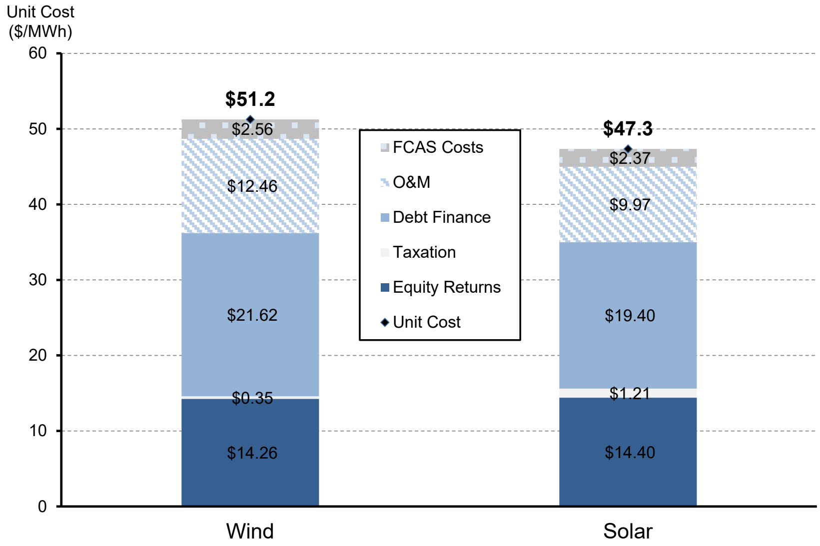
based on contemporary market data drawn from the Reserve Bank of Australia and project bank sources for credit spreads.

Table 3: Project finance assumptions

Renewable Project Finance		
Debt Sizing Constraints		
- DSCR	(times)	1.25
- Gearing Limit	(%)	75.0
- Default	(times)	1.05
Project Finance Facilities - Tenor		
- Term Loan B (Bullet)	(Yrs)	5
- Term Loan A (Amortising)	(Yrs)	7
- Notional amortisation	(Yrs)	25
Project Finance Facilities - Pricing		
- Term Loan B Swap	(%)	0.45
- Term Loan B Spread	(bps)	140
- Term Loan A Swap	(%)	0.64
- Term Loan A Spread	(bps)	160
- Refinancing Rate	(%)	3.60
Expected Equity Returns	(%)	8.0

The combination of data in Tables 2-3 when compiled in the PF Model produce a wind farm capital cost of \$512m with \$374m (73% gearing) in debt facilities and an underlying cost structure (and PPA price) of \$51.20/MWh. The capital cost of the solar PV project is \$240m with \$158m (66% gearing) in project debt and an underlying unit cost and price of \$47.3/MWh. A detailed unit cost stack is presented in Figure 5. Note our cost estimates are the equivalent of a highly granular Levelised Cost of Electricity (LCoE) calculation.

Figure 5: Average unit cost – 250MW Wind and 250MW Solar PV



4.4 REZ Optimisation Model

Our REZ Optimization Model seeks to determine the optimal capacity of a set of connecting generation resources (P_i^G) in a REZ in order to maximise an objective function subject to operational, financial and access scheme constraints. We consider two separate objective functions, viz. the maximization of generation output (OBJ_{GEN}) and net cashflows (OBJ_{CF}):

$$OBJ_{GEN} = \underset{v}{Max} \left(\sum_{t \in T} \sum_{g \in G} p_{g,t}^{g} \right) \quad (1)$$

$$OBJ_{CF} = \underset{v}{Max} \left(\sum_{g \in G} \hat{\vartheta}_g^g \right) \quad (2)$$

$$\hat{\vartheta}_g^g = \sum_{t \in T} p_{g,t}^g \left(\lambda_t^g (1 - \eta_g) - C_g^v - C_g^{as} \right) - C_g^f P_g^g - k_g^d \gamma_g C_g^I P_g^g - k_g^e (1 - \gamma_g) C_g^I P_g^g - C_g^T P^g \quad \forall g \in G \quad (3)$$

$$v = \{ p_{g,t}^g, P^g, \beta_{g,t}^c, x_{g,t}^c, y_{g,t}^c \} \quad (3a)$$

S.T.

$$p_{g,t}^g \le P_g^g \alpha_g^g \forall g \in G, t \in T \quad (4)$$

$$\sum_{g \in G} p_{g,t}^g \le H^R \ \forall t \in T \quad (5)$$

$$\hat{\vartheta}_g^g \ge 0 \ \forall g \in G \quad (6)$$

Where net cashflows $\hat{\vartheta}_g^g$ are equivalent to (i) revenues based on generation dispatch $p_{g,t}^g$ and λ_t^g a price index reflecting either a PPA or spot price adjusted by η_g, a factor reflecting auxiliary energy use and MLFs. C_g^v, C_g^{as}, C_g^f and C_g^I are variable, ancillary service and fixed costs respectively. P_g^g is the generator's installed capacity. Capital structure assumptions informed by the PF model (k_g^d cost of debt, k_g^e cost of equity and γ_g gearing ratio) determine debt service costs and expected equity returns. C_g^T represents an allocation of REZ investment costs.

Constraint 4 limits variable generation to its maximum level based on availability α_g^g, while 5 ensures that the total generation output at a node does not exceed network hosting capacity H^R. Constraint 6 ensures built generation exceeds its required minimum equity rate of return.

5. Model Results – Optimising VRE Capacity

Model results contrast two specific objective functions, i.e. i). maximise output (i.e. PPA seller lens), and ii). maximise net cash flows (i.e. PPA buyer lens).

5.1 Maximise VRE output

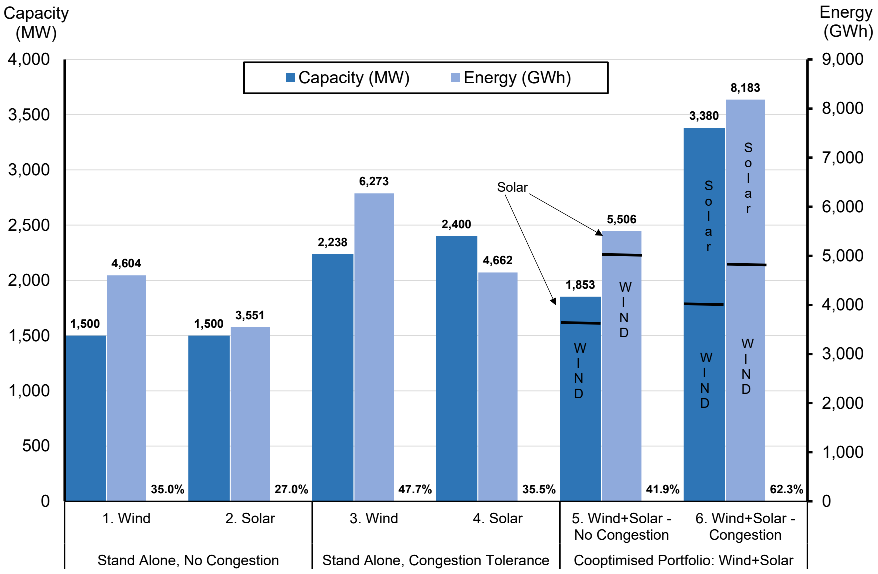
Maximising output can be defined across various dimensions with zero, or minimal, tolerances to REZ network congestion. In early stages of decarbonisation (and low VRE markets shares) the tolerance of investors and project banks to network congestion is likely to be close to zero. However, as VRE market shares rise, this risk appetite must ultimately change. Recall the peak-to-average output ratio of wind plant is typically 3:1 as Newbery (2021) explains. And recall that it has never been practical for all generation plant types across a power system to operate without constraint - even baseload coal plant during the 1980s and 1990s faced output limitations.

The logical array of possibilities is illustrated in Figure 6 with dark bars (LHS Axis) representing MW capacity installed and light bars (RHS Axis) representing energy sent out (GWh). Note at the base of each set of bars is the utilisation of the 1500MW-rated REZ. Six simulations are illustrated:

1. wind, zero congestion;
2. solar, zero congestion;
3. wind, some congestion (i.e. 3 percentage point (ppt) ACF reduction);
4. solar, some congestion (i.e. 5 ppt ACF reduction);

5. optimised wind and solar, zero congestion; and
6. optimised wind and solar, some congestion (i.e. 3 & 5 ppt ACF reduction).

Figure 6: REZ Model results – maximise output



Simulations 1 and 2 (1500MW wind and 1500MW solar) exhibit *practical* REZ ACFs of 35% and 27%, respectively. Recall the *potential* ACF of wind and solar (Fig.4) was 36.1% and 30%. In the Queensland region, negative price events will induce a certain minimum level of economic curtailment such that the *practical* ACF of wind reduces by 1.1% (i.e. 36.1% to 35%) and for solar, by 3% (i.e. 30% to 27%).

Simulations 3 and 4 deliberately oversizes installed wind capacity thus driving the ACF down by a further 3ppt to 32%, and solar by 5ppt to 22% in order to maximise overall GWh output. In the event, this means the optimal capacity of wind (scenario 3) rises to 2238MW, and solar (scenario 4) rises to 2400MW. With these installed capacities, utilisation of the 1500MW REZ is 47.7% and 35.5%, respectively. To be clear on this, in scenario 3, there is 2238MW of wind operating at an ACF of 32% and producing 6273GWh – meaning that utilisation of the 1500MW rated-REZ transmission line is 47.7%.

The final two scenarios examine wind/solar portfolio effects with no congestion (scenario 5) and some congestion (scenario 6). REZ utilisation rises significantly compared to equivalent alternate scenarios (i.e. scenario 5 vs 1 with no congestion, and scenario 6 vs 3 with some congestion) due to the optimal combination of wind and solar, which better utilises scare transmission resources. Note in scenario 6 REZ transmission line utilisation rises to a surprisingly high 62.3%.

5.2 REZ utilisation and implications for REZ charging

REZ charges flowing to VRE generators are sensitive to utilisation of the transmission infrastructure. We illustrate dynamic effects of varying levels of VRE output for the 1500MW REZ assuming transmission capital costs of $100/kW, O&M charges set to 1.5% of the capital cost, and a cost of capital of 4.8%. Using the network model in Simshauser (2021), annual REZ charges amount to ~$10.3 million per annum. How these might then be recovered are presented in Figure 7 under the pricing model outlined in Section 3.1 (i.e. VRE generator carries the risk).

Note in Fig.7 that if only 500MW of wind is developed, breakeven pricing equates to $7.81/MWh. This underscores the critical issue outlined in Section 3, and why variations in user charging outlined in Sections 3.2 and 3.3 may become important. Conversely, it also underscores why Section 3.1 is likely to be a dominant charging model when foundation developments approach REZ capacity. Specifically, at scale (i.e. 1500MW), REZ costs for solar will span the range of $2.89 – 3.55/MWh and for wind ~$2.17/MWh as Fig.7 illustrates. Note also on Fig.7 that the optimal plant mix with zero congestion, or with some congestion, will face REZ charges of $1.78 and $1.28/MWh, respectively. In the context of underlying LCoEs for VRE of $47-50/MWh, these REZ connection/user charges present as relatively modest.

Figure 7: REZ charges 'maximise output'

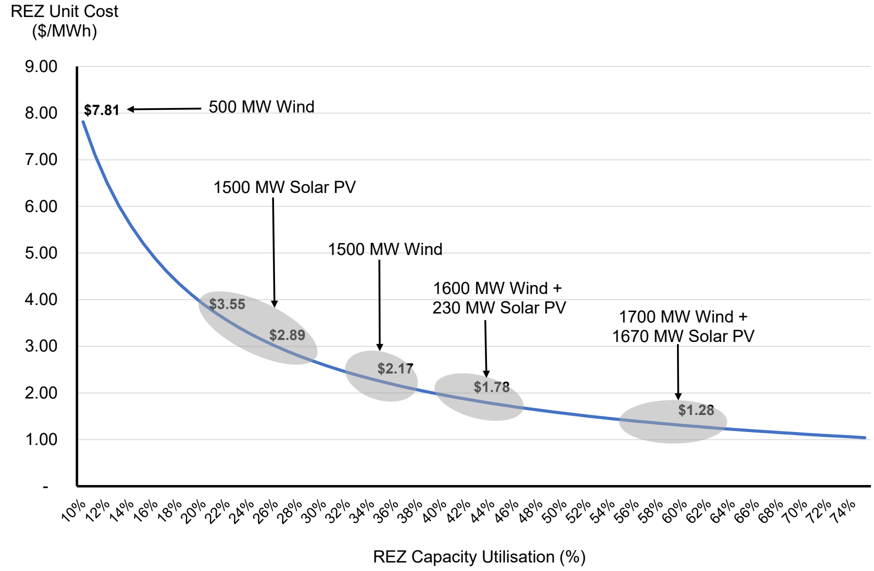
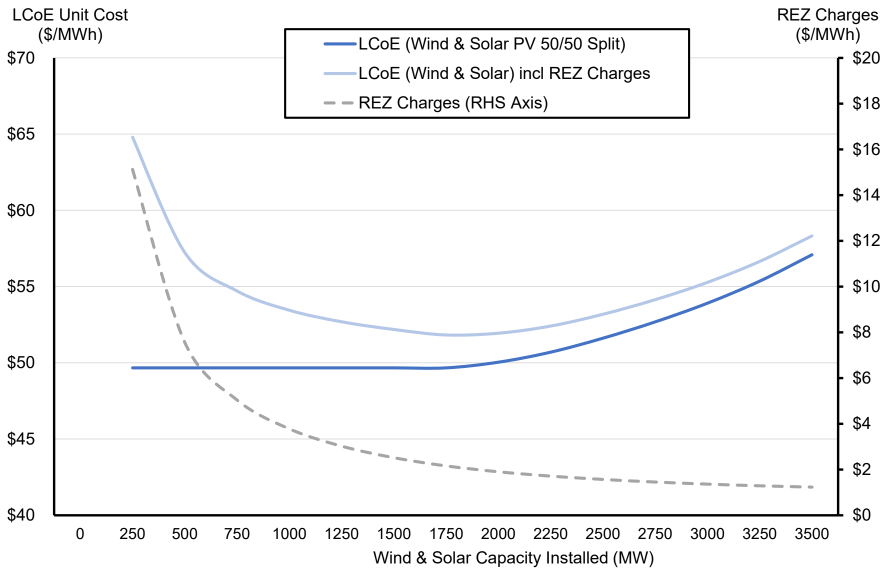


Figure 8 further explores these interactions by illustrating a portfolio LCoE based on a 50/50 MW split between wind and solar with capacity ranging from 250MW to 3500MW. The dark blue line (LHS Axis) in Fig.8 measures the LCoE of VRE, and the light blue line (LHS Axis) measures the LCoE of the combined VRE and REZ transmission charges. The grey dashed line (RHS Axis) plots REZ charges, which start at $16/MWh for 250MW of capacity and fall to $1.20/MWh at 3500MW capacity.

Figure 8: Unit cost of generation (incl. REZ charges & curtailment)



Notice in Fig.8 the LCoE of VRE capacity (dark line) is flat until ~1800MW, at which point curtailment adversely impacts unit costs. Consequently, the combined LCoE of VRE plant and REZ transmission (light line) reaches its lowest point at ~1800MW – thereafter, congestion effects dominate reductions in REZ charges.

Prima facie, this might tend to suggest 1800MW of installed plant represents optimality. However as is well documented in the literature (see Joskow, 2011; Mills, Wiser and Lawrence, 2012; Nicolosi, 2012; Edenhofer *et al.*, 2013; Hirth, 2013; Simshauser, 2018), while LCoE of VRE plant is an important metric, it is the market value of plant that determines their worth in energy markets.

5.3 Spot prices and the market value of VRE output

The interaction between spot prices and VRE plant is generally well understood. Early-stage solar PV plant can be expected to earn slightly more than baseload prices because output coincides with peak period (i.e. daytime) prices. But as solar PV increases market share this relationship reverses (Hirth, 2013; Simshauser, 2018; Bushnell and Novan, 2021). The market value of PV begins to contract because solar fleet output is *highly correlated* and in turn *cannibalises* its own market. At a power system level, what was once a peak period begins to exhibit all the characteristics of an off-peak period[30].

Figure 9 illustrates this relationship using historical Queensland spot price data from 2015 (solar market share =3%, LHS panel) and 2020 (solar market share =12%, RHS panel). The LHS panel of Fig.9 identifies 2015 baseload prices at $52/MWh, and the market value of solar PV (30% ACF) at $58/MWh – a 12% *premium* to baseload prices. There were no negative spot price events during daylight hours in 2015 and therefore no economic curtailment. Consequently, *practical output* (30%) equalled *potential output* (30%).

The RHS panel of Fig.9 presents a very different picture for the market value of solar. By 2020, solar market share reached 12% and the market value of output was just $31/MWh, a 25% *discount* to baseload prices. During 2020 there were 659 half-hour trading intervals in which spot prices were negative – consequently – economic curtailment of the plant means practical output falls to 27% ACF, and in doing so, improves the market value of its output from $31/MWh to $38/MWh. When forming part of an optimised REZ, the market value of output remains largely constant (nb. albeit a 10c rise in market value) but output falls to 23.7% ACF.

[30] Including capacity oversupply, low prices, and binding minimum loads vis-à-vis baseload thermal plant output.

Figure 9: Market value of solar PV – 2015 v 2020 Queensland

Fig.9a - Price

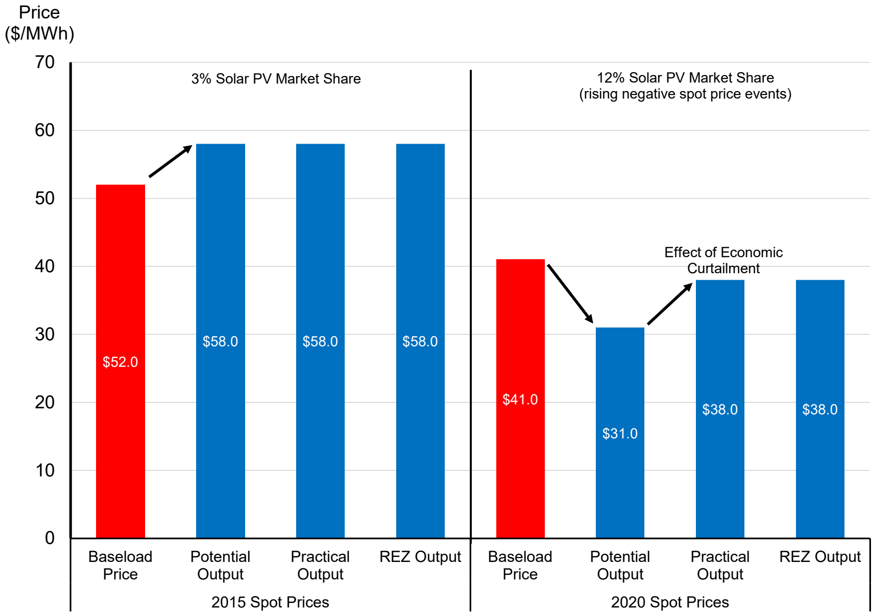
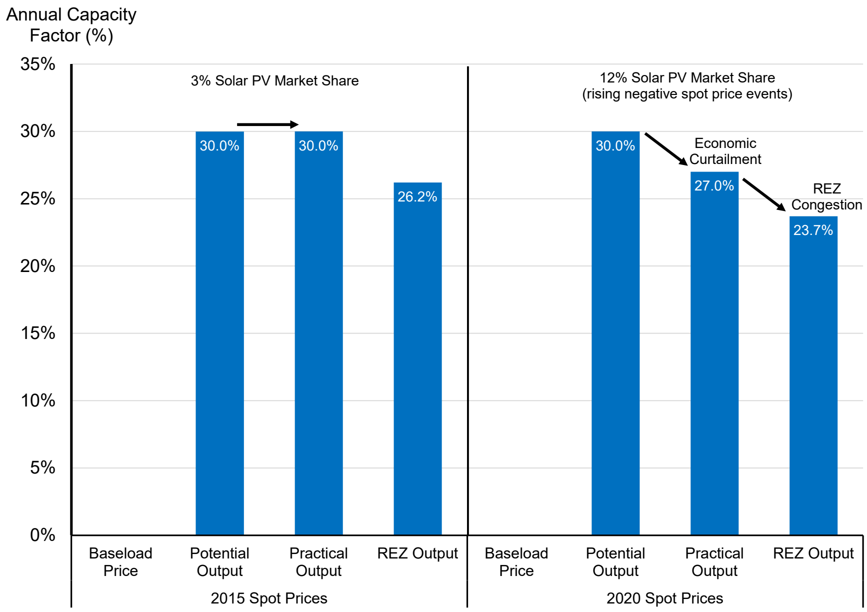


Fig.9b – Output



In contrast to solar, the diurnal pattern of wind in Queensland has an off-peak (evening) bias, as Fig.2 illustrated. This means the market value of wind (in a pre-solar market) will, all else equal, exhibit a slight discount to base prices. Holding base plant capacity constant, rising wind market share is also associated with generalised merit order effects (see Forrest and MacGill, 2013; Bell *et al.*, 2017; Bushnell and Novan, 2021).

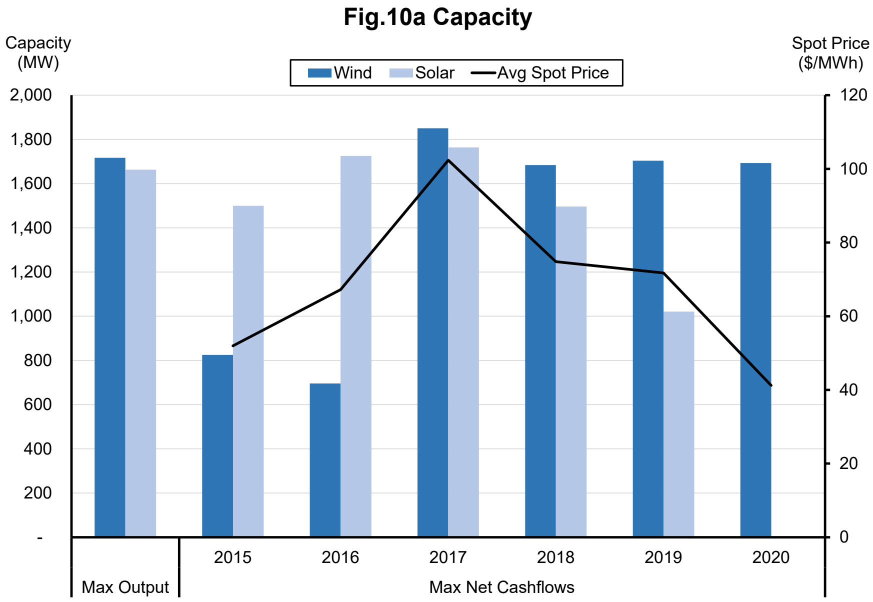
Interestingly enough however, interactions between wind and *extensive solar* can benefit wind. As solar PV market share expands, daytime spot prices fall but shoulder period prices may rise materially (see Simshauser, 2020; Bushnell and Novan, 2021). Consequently, while rising wind is usually associated with merit order effects (holding base plant constant), it is also plausible that with rising solar PV the market value of wind reverses and trades at a premium to base prices. This is more probable if baseload plant capacity adjusts following VRE entry (i.e. merit order effects are reversed as outlined in

Hirth 2013 and Simshauser, 2020). The key variables here are i). the extent of solar PV, and ii). the extent to which base plant adjusts with the entry of wind. In the case of Queensland, baseload prices averaged $41 (per Fig.9) while market value of wind was $44/MWh, a 7% *premium* to base prices.

5.4 Maximise VRE net cashflows

In our final analysis, we optimise VRE capacity for each year spanning the period 2015 to 2020 with our constraint turning to maximising net cashflows. That is, given prevailing spot prices in 2015 – what would the profit maximising combination of wind/solar be? This optimisation process is repeated for each individual year 2015-2020. We contrast these optimisation results with those derived from Section 5.1 (maximise VRE output, LHS bars). Figure 10 illustrates optimisation model results for installed capacity (MW) and energy (GWh) for each year spanning 2015-2020. The variation in results in Figure 10 is being driven by the market value of VRE output, and this is most aptly captured through Figure 11 (and note market value of output is compared to the broad LCoE range of wind/solar):

Figure 10: Optimal REZ capacity maximising VRE net cashflows- 2015 to 2020



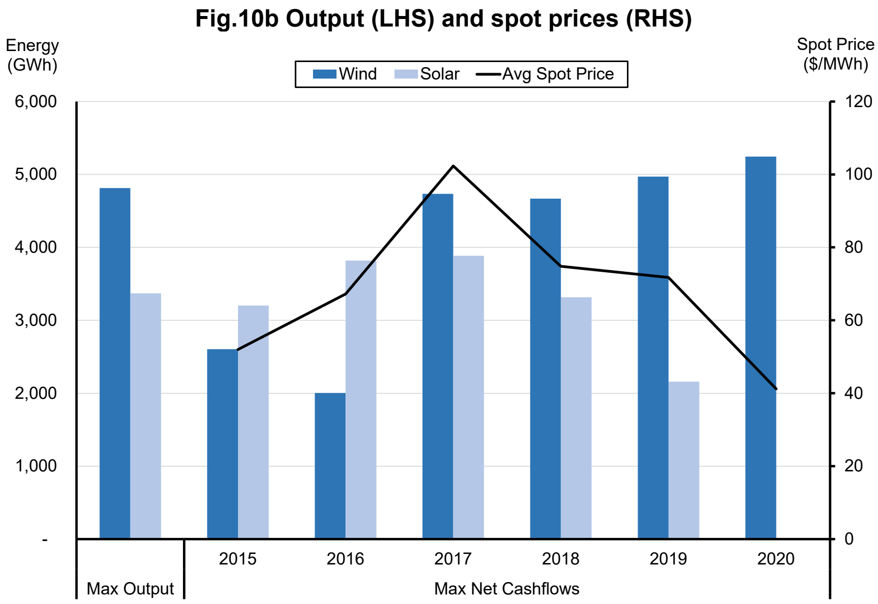
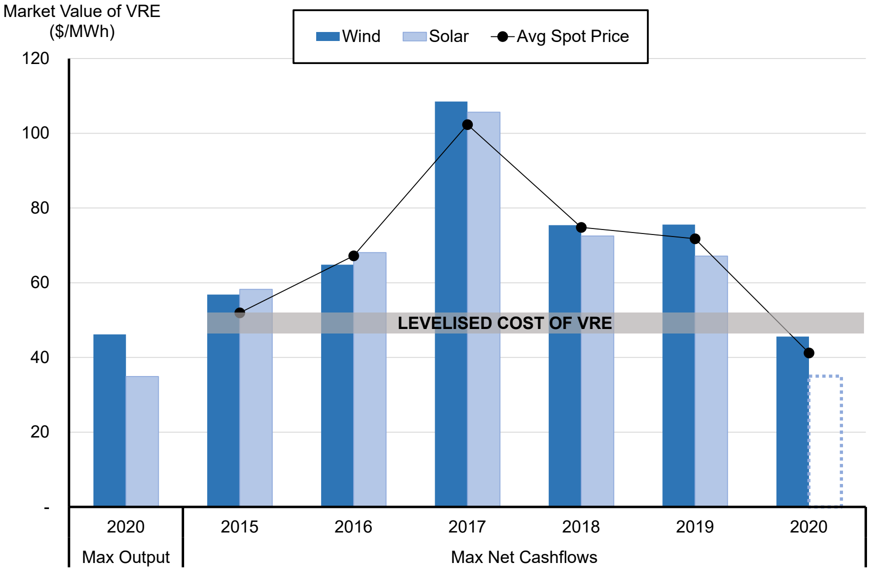


Figure 11: The market value of VRE output



There are three central observations arising from these *net cashflow* optimisations:

1. Optimal installed capacity within a notional 1500MW REZ when the objective is to maximise output with moderate levels of congestion resulted in approximately 1700MW of wind, and 1700MW of solar. When the market value of VRE drives decision-making (i.e. by sophisticated PPA 'buyers') there is considerable variation in plausible outcomes.

2. For any year over the period 2015-2018 when its market share was relatively low (albeit rising), solar PV investment and output would approach or even exceeded the 'maximise VRE output' benchmark (LHS bars in Fig.10). However in relative terms, wind becomes an increasingly dominant share of the portfolio from 2017 onwards given the 'price impressing effects' associated with rising solar PV market share.

3. By 2020 given a general market oversupply, incremental solar PV appears uneconomic (albeit holding technology costs constant), while wind was marginal in the absence of renewable certificates. Note that 2021 prices in Queensland have subsequently rebounded.

6. Policy implications and concluding remarks

Australia's NEM experienced a sharp increase in VRE investment commitments during the 2016-2021 supercycle. A subset of VRE projects experienced considerable entry frictions, with network hosting capacity becoming a genuine constraint. One promising policy proposal has been the concept of REZ. The purpose of this article was to examine optimal VRE plant capacity within a 1500MW radial REZ and explored what 'full subscription' of a REZ may look like under varying PPA buyer/seller tolerances and conditions.

Specifically, our modelling examined REZ subscription from three perspectives, i). minimising overall costs, I). a developer's lens (i.e. maximise output) and ii). PPA buyer lens (i.e. maximise net cashflows). Results in Section 5 highlighted that if minimising the combined unit cost of VRE and REZ infrastructure forms the objective function, optimal subscription would be achieved at ~1800MW of solar and wind, 300MW above the REZ thermal limit given Southern Queensland wind/solar resources. If maximising output forms the objective function (i.e. *via endless PPA buyer capacity*) then capacity additions could vastly exceed REZ thermal limits – with the fully subscribed REZ comprising ~3400MW of VRE. Conversely, maximising net cashflows produced rich variations in subscription results, driven by the maket value of plant output under varying spot market conditions (i.e. PPA buyer lens). Modelled solar deployment tended to correlate with higher historical base pricing years, and was dampened in recent base years due to a price impression effect associated with scale increases in system-wide solar PV investments.

The choice of structure for non-regulated REZ transmission infrastructure is not only critical in terms of funding, but also rights given to participants in exchange for underwriting oversized, scale-efficient capacity. These rights will drive decisions around the generation mix of wind and solar resources, the timing, the balance of REZ charges versus congestion tolerances and therefore REZ utilisation and optimisation. In terms of policy implications, noting our results and conclusions face the limitation of excluding battery storage co-optimisation effects, we believe there are three key out-workings.

First, the unit cost of REZs falls sharply with utilisation. Some minimum level of asset utilisation is clearly important but gains from greater capacity addition must balance against costs of congestion. Forecast levels of congestion (at acceptable levels to REZ foundation generators) needs some bounding and allocation of tradable property right to regulate ultimate REZ outcomes. At the time of writing, likely future economic levels of marginal VRE congestion is *not* well understood in the NEM. Consequently, current investor appetite to congestion is very low. But for reasons articulated by Newbery (2021), and as Section 5 illustrated, investor appetite will be forced to loosen as VRE market shares expand significantly.

Based on Figure 8 data, our view of minimum economic utilisation of a 1500MW REZ was ~1000MW of wind. This suggests REZ pricing under Section 3.1 (i.e. generators carry the risk) is likely to be viable when 1000MW+ of foundation plant commitments are present. If foundation commitments are materially lower than 1000MW, REZ transmission charges are likely to be *punitive* relative to VRE entry costs. At this point, pricing under Sections 3.2 or 3.3 (i.e. transmission planner or government) will become important mechanisms to facilitate REZ developments.

A second outworking from our analysis was the changing fortunes of solar PV in Queensland. Initially in 2015-2017, solar represented the dominant technology for REZ deployment based on maximisation of net cashflows (see Fig.10-11). However as solar market share increased, the market value of output decreased given minimal supply-side adjustment vis-à-vis Queensland coal plant.

Third, predicting how an (initially) under-subscribed REZ might evolve to full subscription levels vis-à-vis the mix of solar and wind is complex. The risk of transient underutilisation is material in the absence of known PPA underwriters. There should be no doubt that if an endless supply of PPAs underwriters exists at financeable rates, investment in VRE plant would flow seamlessly to the upper end of credible capacity, and REZ charging would be trivial per Fig.7. Conversely, only a benevolent PPA underwriter who absorbs spot price volatility associated with VRE could ensure a REZ achieves a maximum output scenario in the short run. Market results over the period 2015-2020 (Fig.10-11) illustrates that optimality is a dynamic problem.

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APPENDIX I – PF Model Overview

In the PF Model, costs increase annually by a forecast general inflation rate (CPI). Prices escalate at a discount to CPI. Inflation rates for revenue streams π_j^R and cost streams π_j^C in period (year) *j* are calculated as follows:

$$\pi_j^R = \left[1 + \left(\frac{CPI \times \alpha_R}{100}\right)\right]^j \text{, and } \pi_j^C = \left[1 + \left(\frac{CPI \times \alpha_C}{100}\right)\right]^j, \tag{A.1}$$

The discounted value for α_R reflects single factor learning rates that characterise generating technologies.

Energy output q_j^i from each plant (*i*) in each period (*j*) is a key variable in driving revenue streams, unit fuel costs and variable Operations & Maintenance costs. Energy output is calculated by reference to installed capacity k^i, capacity utilisation rate CF_j^i for each period *j*. Plant auxillary losses Aux^i arising from on-site electrical loads are deducted.

$$q_j^i = CF_j^i . k^i . (1 - Aux^i), \tag{A.2}$$

A convergent electricity price for the *i*th plant $(p^{i\varepsilon})$ is calculated in year one and escalated per eq. (1). Thus revenue for the *i*th plant in each period *j* is defined as follows:

$$R_j^i = (q_j^i . p^{i\varepsilon} . \pi_j^R), \tag{A.3}$$

In order to define marginal running costs, the thermal efficiency for each generation technology ζ^i needs to be defined. The constant term '3600'[31] is divided by ζ^i to convert the efficiency result from % to kJ/kWh. This is then multiplied by raw fuel commodity cost f^i. Variable Operations & Maintenance costs v^i, where relevant, are added which produces a pre-carbon short run marginal cost. Under conditions of externality pricing CP_j, the CO_2 intensity of output needs to be defined. Plant carbon intensity g^i is derived by multiplying the plant heat rate by combustion emissions $\dot{g}^i$ and fugitive CO_2 emissions $\hat{g}^i$. Marginal running costs in the *j*th period is then calculated by the product of short run marginal production costs by generation output q_j^i and escalated at the rate of π_j^C.

$$\vartheta_j^i = \left\{\left[\left(\frac{\left(3600/\zeta^i\right)}{1000} . f^i + v^i\right) + \left(g^i . CP_j\right)\right] . q_j^i . \pi_j^C \middle| g^i = \left(\dot{g}^i + \hat{g}^i\right) . \frac{\left(3600/\zeta^i\right)}{1000}\right\}, \tag{A.4}$$

Fixed Operations & Maintenance costs FOM_j^i of the plant are measured in \$/MW/year of installed capacity FC^i and are multiplied by plant capacity k^i and escalated.

$$FOM_j^i = FC^i . k^i . \pi_j^C, \tag{A.5}$$

Earnings Before Interest Tax Depreciation and Amortisation (EBITDA) in the *j*th period can therefore be defined as follows:

$$EBITDA_j^i = \left(R_j^i - \vartheta_j^i - FOM_j^i\right), \tag{A.6}$$

Capital Costs (X_0^i) for each plant *i* are Overnight Capital Costs and incurred in year 0. Ongoing capital spending (x_j^i) for each period *j* is determined as the inflated annual assumed capital works program.

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[31] The derivation of the constant term 3600 is: 1 Watt = 1 Joule per second and hence 1 Watt Hour = 3600 Joules.

$$x_j^i = c_j^i . \pi_j^C , \quad \text{(A.7)}$$

Plant capital costs X_0^i give rise to tax depreciation (d_j^i) such that if the current period was greater than the plant life under taxation law (L), then the value is 0. In addition, x_j^i also gives rise to tax depreciation such that:

$$d_j^i = \left(\frac{X_0^i}{L}\right) + \left(\frac{x_j^i}{L-(j-1)}\right), \quad \text{(A.8)}$$

From here, taxation payable $\left(\tau_j^i\right)$ at the corporate taxation rate (τ_c) is applied to $EBITDA_j^i$ less Interest on Loans $\left(I_j^i\right)$ later defined in (16), less d_j^i. To the extent $\left(\tau_j^i\right)$ results in non-positive outcome, tax losses $\left(L_j^i\right)$ are carried forward and offset against future periods.

$$\tau_j^i = Max\left(0, \left(EBITDA_j^i - I_j^i - d_j^i - L_{j-1}^i\right). \tau_c\right), \quad \text{(A.9)}$$

$$L_j^i = Min\left(0, \left(EBITDA_j^i - I_j^i - d_j^i - L_{j-1}^i\right). \tau_c\right), \quad \text{(A.10)}$$

The debt financing model computes interest and principal repayments on different debt facilities depending on the type, structure and tenor of tranches. There are two types of debt facilities – (a) corporate facilities (i.e. balance-sheet financings) and (2) project financings. Debt structures include semi-permanent amortising facilities and bullet facilities.

Corporate Finance typically involves 5- and 7-year bond issues with an implied 'BBB' credit rating. Project Finance may include a 5-7 year Bullet facility requiring interest-only payments after which it is refinanced with consecutive amortising facilities and fully amortised over an 18-25 year period (depending on the technology) and a second facility commencing with tenors of 5-12 years as an Amortising facility set within a semi-permanent structure with a nominal repayment term of 18-25 years. The decision tree for the two tranches of debt was the same, so for the Debt Tranche where DT = 1 or 2, the calculation is as follows:

$$if\ j \begin{cases} > 1, DT_j^i = DT_{j-1}^i - P_{j-1}^i, \\ = 1, DT_1^i = D_0^i . S \end{cases} \quad \text{(A.11)}$$

D_0^i refers to the total amount of debt used in the project. The split (S) of the debt between each facility refers to the manner in which debt is apportioned to each tranche. In most model cases, 35% of debt is assigned to Tranche 1 and the remainder to Tranche 2. Principal P_{j-1}^i refers to the amount of principal repayment for tranche T in period j and is calculated as an annuity:

$$P_j^i = \left(\frac{DT_j^i}{\left[\frac{1-\left(1+\left(R_{Tj}^Z + C_{Tj}^Z\right)\right)^{-n}}{R_{Tj}^Z + C_{Tj}^Z}\right]} \middle| z \begin{cases} = VI \\ = PF \end{cases} \right), \quad \text{(A.12)}$$

In (12), R_{Tj} is the relevant interest rate swap (5yr, 7yr or 12yr) and C_{Tj} is the credit spread or margin relevant to the issued Debt Tranche. The relevant interest payment in the j^{th} period $\left(I_j^i\right)$ is calculated as the product of the (fixed) interest rate on the loan by the amount of loan outstanding:

$$I_j^i = DT_j^i \times \left(R_{Tj}^z + C_{Tj}^z\right), \tag{A.13}$$

Total Debt outstanding D_j^i, total Interest I_j^i and total Principle P_j^i for the i^{th} plant is calculated as the sum of the above components for the two debt tranches in time *j*. For clarity, Loan Drawings are equal to D_0^i in year 1 as part of the initial financing and are otherwise 0.

One of the key calculations is the initial derivation of D_0^i (as per eq.11). This is determined by the product of the gearing level and the Overnight Capital Cost $\left(X_0^i\right)$. Gearing levels are formed by applying a cash flow constraint based on credit metrics applied by project banks and capital markets. The variable γ in our PF Model relates specifically to the legal structure of the business and the credible capital structure achievable. The two relevant legal structures are Vertically Integrated (VI) merchant utilities (issuing 'BBB' rated bonds) and Independent Power Producers using Project Finance (PF).

$$iif\ \gamma \begin{cases} = VI,\ \frac{FFO_j^i}{I_j^i} \geq \delta_j^{VI} \forall\, j \ \Big| \frac{D_j^i}{EBITDA_j^i} \geq \omega_j^{VI} \forall\, j \ \Big| FFO_j^i = \left(EBITDA_j^i - x_j^i\right) \\ = PF, Min\left(DSCR_j^i, LLCR_j^i\right) \geq \delta_j^{PF}, \forall\, j \ \Big| DSCR_j = \frac{\left(EBITDA_j^i - x_j^i - \tau_j^i\right)}{P_j^i + I_j^i} \Big| LLCR_j = \frac{\sum_{j=1}^{N}\left[\left(EBITDA_j^i - x_j^i - \tau_j^i\right).(1+K_d)^{-j}\right]}{D_j^i} \end{cases}, \tag{A.14}$$

Credit metrics[32] $\left(\delta_j^{VI}\right)$ and $\left(\omega_j^{VI}\right)$ are exogenously determined by credit rating agencies and are outlined in Table 3. Values for δ_j^{PF} are exogenously determined by project banks and depend on technology (i.e. thermal vs. renewable) and the extent of energy market exposure, that is whether a Power Purchase Agreement exists or not. For clarity, FFO_j^i is 'Funds From Operations' while $DSCR_j^i$ and $LLCR_j^i$ are the Debt Service Cover Ratio and Loan Life Cover Ratios. Debt drawn is:

$$D_0^i = X_0^i - \sum_{j=1}^{N}\left[EBITDA_j^i - I_j^i - P_j^i - \tau_j^i\right].(1+K_e)^{-(j)} - \sum_{j=1}^{N} x_j^i.(1+K_e)^{-(j)}, \tag{A.15}$$

At this point, all of the necessary conditions exist to produce estimates of the long run marginal cost of power generation technologies along with relevant equations to solve for the price $\left(p^{i\varepsilon}\right)$ given expected equity returns (K_e) whilst simultaneously meeting the constraints of δ_j^{VI} and ω_j^{VI} or δ_j^{PF} given the relevant business combinations. The primary objective is to expand every term which contains $p^{i\varepsilon}$. Expansion of the EBITDA and Tax terms is as follows:

$$0 = -X_0^i + \sum_{j=1}^{N}\left[\left(p^{i\varepsilon}.q_j^i.\pi_j^R\right) - \vartheta_j^i - FOM_j^i - I_j^i - P_j^i - \left(\left(p^{i\varepsilon}.q_j^i.\pi_j^R\right) - \vartheta_j^i - FOM_j^i - I_j^i - d_j^i - L_{j-1}^i\right).\tau_c\right].(1+K_e)^{-(j)} - \sum_{j=1}^{N} x_j^i.(1+K_e)^{-(j)} - D_{0,}^i \tag{A.16}$$

The terms are then rearranged such that only the $p^{i\varepsilon}$ term is on the left-hand side of the equation:

Let $IRR \equiv K_e$

$$\sum_{j=1}^{N}(1-\tau_c).p^{i\varepsilon}.q_j^i.\pi_j^R.(1+K_e)^{-(j)} = X_0^i - \sum_{j=1}^{N}\left[-(1-\tau_c).\vartheta_j^i - (1-\tau_c).FOM_j^i - (1-\tau_c).\left(I_j^i\right) - P_j^i + \tau_c.d_j^i + \tau_c L_{j-1}^i).(1+K_e)^{-(j)}\right] + \sum_{j=1}^{N} x_j^i.(1+K_e)^{-(j)} + D_{0,}^i \tag{A.17}$$

The model then solves for $p^{i\varepsilon}$ such that:

[32] For Balance Sheet Financings, Funds From Operations over Interest, and Net Debt to EBITDA respectively. For Project Financings, Debt Service Cover Ratio and Loan Life Cover Ratio.

$$p^{i\varepsilon} = \frac{X_0^i}{\sum_{j=1}^{N}(1-\tau_c).P^{\varepsilon}.\pi_j^R.(1+K_e)^{-(j)}} + \frac{\sum_{j=1}^{N}\Big((1-\tau_c).\vartheta_j^i+(1-\tau_c).FOM_j^i+(1-\tau_c).\left(I_j^i\right)+P_j^i-\tau_c.d_j^i-\tau_c L_{j-1}^i).(1+K_e)^{-(j)}\Big)}{\sum_{j=1}^{N}(1-\tau_c).q_j^i.\pi_j^R.(1+K_e)^{-(j)}} + \frac{\sum_{j=1}^{N} x_j^i.(1+K_e)^{-(j)}+D_0^i}{\sum_{j=1}^{N}(1-\tau_c).q_j^i.\pi_j^R.(1+K_e)^{-(j)}}. \tag{A.18}$$