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Paul Simshauser   David Newbery

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Non-Firm vs Priority Access: on the Long Run Average and Marginal Cost of Renewables in Australia

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December 2023

Abstract

Australia's National Electricity Market (NEM) has experienced a rapid expansion of Variable Renewable Electricity (VRE) projects, not without obstacles. Entry frictions such as movements in Marginal Loss Factors and/or network congestion adversely impacted ~15% of new projects. Are these the expected results in a workably functioning market, or due to market design defects? Policy advisors have sought to reform the NEM's non-firm, open-access regime, warranted as the ratio of maximum-to-average wind output is ~3 times and for solar PV is 4 times. As VRE market shares increase, curtailment will increase rapidly through excess generation and/or network congestion. But access reform focused solely on congestion and curtailment may have unintended consequences as a careful analysis of the difference between average and marginal curtailment rates demonstrates. Malalignment between market conventions and access policy may distort entry, raise consumer prices and harm welfare. Our model results suggest in the NEM, switching from open- to priority access damages consumer welfare by A$169m per annum in each Renewable Energy Zone.

Keywords: Renewables, Network Congestion, Curtailment, Marginal Curtailment, Renewable Energy Zones.

JEL Codes: D52, D53, G12, L94 and Q40.

1. Introduction

In Australia's National Electricity Market (NEM) over the period 2016-2023, 158 wind and solar PV projects had reached financial close totalling 22GW and A$43 billion[1], forming a renewable investment supercycle (Simshauser & Gilmore, 2022). Along with this fleet of utility-scale Variable Renewable Electricity (VRE, intermittent wind and solar) was a further 9GW of flexible firming capacity (batteries, pumped hydro, gas turbines) and 16GW of rooftop solar PV. By the end of 2023, the NEM had reached a 38% renewable market share, with VRE comprising 31%.

One issue of concern to Australian policy advisors is network access and whether the NEM's historic non-firm, open access regime should be replaced with a form of 'priority access' whereby VRE investors have greater security over production output. With rising levels of VRE, high renewable production periods in excess of aggregate final demand or existing network capacity will predictably result in 'spilled' renewable output. Rising renewable market share therefore means curtailment will rise. This is thought to require policy adjustment vis-à-vis the connection and access of VRE projects.

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[1] At the time of writing, AUD $1.00 = US $0.65 and GBP 0.52.

Yet an issue which appears not well understood by NEM policy advisors is the difference between the average and the marginal rates of VRE curtailment, and their interaction with the access regime (see Newbery, 2024). Average curtailment rates can be expected to rise gradually. Marginal curtailment rates, as our analysis subsequently illustrates, may rise at 3-4 times average rates. This has significant implications for producer and consumer welfare – and any changes to network access is at the core of these implications.

Concerns underpinning network access most likely relate to perceptions of VRE investor confidence in the NEM. Surveys undertaken by Australia's Clean Energy Council over the past five years persistently feature at least three items as central concerns of renewable investors, viz.

i. complexity of grid connection,
ii. inadequate network hosting capacity, and
iii. policy uncertainty stemming from persistent proposals to alter the NEM's design.

On i), there is no question grid connection complexity has increased. But complexity is a technical necessity if power system security is to be maintained. Continual loss of synchronous coal generators and the mass entry of 'grid following' asynchronous VRE has led to system strength shortfalls in certain locations (Badrzadeh *et al.*, 2020; Hardt *et al.*, 2021; Qays *et al.*, 2023). Before Connection and Access Agreements can be finalised, extensive studies of Generator Performance Standards (s.5.3.4a of the NEM Rules) and System Strength impacts (s.5.3.4b) must be completed satisfactorily – a complex, costly exercise for renewable investors that typically adds six months to development lags.

But this grid connection cost and complexity has an upside. The processes required during the final stages of securing a Connection and Access Agreement – satisfying s.5.3.4a and s5.3.4b being necessary pre-conditions for Project Finance – follows a 'first ready, first served' approach. One benefit of this cost and complexity is that so-called *zombie projects* are screened out, thus providing room for legitimate projects to reach financial close and proceed to construction within weeks of the Connection and Access Agreement being signed. In contrast, other significant energy markets including PJM, CAISO and Great Britain operate on a 'first come, first served' basis and as a result are characterised by *chronic connection queues* and a prevalence of *zombie projects,* creating multi-year lags for legitimate project entry (Millstein *et al.*, 2021; Seel *et al.*, 2023).

The second investor concern – inadequate network hosting capacity – is unsurprising following the entry of 22GW of VRE projects across 158 sites during the 2016-2023 supercycle. There is evidence of capacity constraints, and these may take some time to resolve. Specifically, VRE project connections in NEM regions are visibly trending from low cost, lower voltage and increasingly congested existing substations (110kV, 132kV, 220kV) to higher voltage 275kV, 330kV and 500kV entry points (Rystad Energy, 2023). Higher voltage connections are more capital intensive, face longer lead times, frequently involve greenfield cut-ins requiring new switching stations, all of which compounds entry costs.

In response, Renewable Energy Zone (REZ) initiatives in Australia's NEM are intended to create the requisite new VRE hosting capacity. Each NEM region has followed a different REZ policy pathway. In Victoria centrally coordinated REZ augmentations are confronting community opposition to transmission developments along with new laws on land access, both of which create commitment delays. In New South Wales (NSW) the chosen contestable REZ framework is running years behind schedule[2] – 'contestability' of infrastructure development and 'speed' are rarely complementary attributes.

Queensland REZs have followed a different market-led, merchant pathway. Two non-regulated (i.e. merchant) REZs on the Southern Downs and Western Downs have been triggered by 'first ready' cornerstone renewable investment commitments by large wind farms. As merchant transmission assets, REZ user charges are levied on connecting and anticipated future generators rather than directly allocated to end-use consumers via the Regulatory Asset Base (see Simshauser, 2021, 2024; Simshauser, Billimoria and Rogers, 2022). Queensland's merchant REZs have also been delivered rapidly – from concept to expected energisation in 3-4 years, with capital costs for each 2GW REZ at ~A$200 million. Two more merchant REZs (at 2GW each) are under active development. As market-led investments, REZ commitments move in line with 'anchor tenant' renewable projects.

The third concern of renewable investors, *policy uncertainty*, relates to constant proposals to alter NEM design elements of central importance to the investment committees of equity and debt providers. Various proposals by policy advisors to alter the NEM market design have been persistent throughout the renewable supercycle. To generalise, these proposals appear to be motivated by the possibility of looming entry frictions. These can in turn be condensed down to two issues, i). perceptions of inadequate locational signals, and ii). the perceived intractability of sharply rising *congestion risks* confronting future entrants.

Ironically, the policy proposals are viewed as unhelpful by Australian renewable investors (see Simshauser & Gilmore, 2022) with Bashir (2020) documenting the extent of this in some detail. Parallel proposals in Great Britain are being met with equivalent reception by British renewable investors (Gowdy, 2022; Frontier Economics, 2023; FTI Consulting and Energy Systems Catapult, 2023). In the Australian case, Commonwealth and State Energy Ministers have thus far rejected *design tinkering* proposals given feedback from utilities, renewable developers and capital market participants.[3]

Some level of rising congestion and VRE curtailment in energy markets appears inevitable and the concept of average market curtailment rates is generally well understood (see Klinge Jacobsen and Schröder, 2012; Bird et al., 2016a; Du and Rubin, 2018; Joos and Staffell, 2018; Millstein et al., 2021; O'Shaughnessy et al., 2021). However, a material difference exists between progressively rising average curtailment rates, and the marginal rate of curtailment. Marginal curtailment rates will run at multiples (3 – 4 times) of the average curtailment rate (Newbery, 2021, 2023a, 2023b). This has significant welfare implications for access regimes for a given market design.

[2] At the time of drafting the Central West Orana REZ had failed to reach a final investment decision after being flagged in 2020 (see https://www.transgrid.com.au/projects-innovation/central-west-orana-rez-transmission-wollar-substation-upgrade). It is unlikely to be commissioned before 2028.
[3] The response by Commonwealth and State Energy Ministers also includes dismantling the Energy Security Board.

If rising congestion in an increasingly renewables-based power system is inevitable, its management is important and policy advisors are right to consider appropriate policy adjustments. However, care must be taken with access reform. Well-intended *intuitive policy prescriptions* can produce the exact opposite effects to that intended, including reduced REZ asset productivity, compounded entry complexity, higher market prices and lower VRE quantities – all of which harm welfare and make achieving renewable targets harder.

The purpose of this article is to examine the welfare implications of average and marginal curtailment rates in a multi-zonal wholesale gross pool electricity market setup with imperfect expansion paths. This is an understudied topic across most of the world's major electricity markets. Our analysis is based on the principles and constructs set out in Newbery (2021, 2023a, 2023b), albeit adjusted for Australian market conditions. Specifically, we model a Queensland REZ with ~1500MW of network hosting capacity. Our suite of optimisation models identify generalised entry costs, then derive the optimal mix of wind and solar for a REZ. Consistent with Newbery's (2021, 2023b) Irish and British data, we find marginal curtailment rates run at multiples of average curtailment rates. The crucial aspect of the merchant REZ approach is that connecting generators pay for the cost of the REZ. In contrast to regimes in which generators do not pay for access (most European countries, where all the transmission costs are levied to load), paying the cost of access to the REZ makes the current pro-rata curtailment lead to a socially optimal level of VRE entry, while priority access comparatively reduces entry (Newbery, 2024).

We demonstrate this by comparing the NEM's existing non-firm regime with an alternative 'priority access' regime. Perhaps counterintuitively, the NEM's existing market design and forward market conventions mean a change to priority access would constrain entry significantly below efficient levels, raise consumer prices, or both – in either case harming welfare. Yet in other jurisdictions lacking efficient transmission charges and with compensation for curtailed (spilled) renewable energy ultimately borne by consumers, the exact opposite prevails. This apparent paradox can be explained by differences in wholesale spot electricity market design, forward market conventions and access arrangements. Just as the world's major power systems comprise an array of market designs, any policy response to renewable curtailment needs to be devised and adjusted to the relevant conditions and context.

This article is structured as follows. Section 2 provides a review of literature. Section 3 introduces our models and data. Sections 4-6 review model results. Policy implications and concluding remarks follow.

2. Review of Literature

Decarbonising power systems presents a sequence of different challenges for investors, power system planners and policymakers. Initially with modest VRE market shares (up to ~10%), the main challenge was cost. Early-stage VRE deployment occurred before learning curve effects and economies of scale led to falls in unit costs (see Newbery, 2018, Grubb & Newbery, 2018). Consequently, entry of onshore wind and solar PV historically required some form of subsidy by way of Feed-in Tariffs (CEER, 2015), renewable certificate schemes (Nelson *et al.*, 2013), mandated renewable portfolio standards (Feldman and Levinson, 2023) or central auction for Contracts-for-Differences

(Newbery, 2023a). Technical challenges in this early stage of renewables deployment were easily managed and integration costs low (Heptonstall and Gross, 2020).

As renewable market shares move beyond ~10% and through to ~20%, merit order effects became predictable and pronounced (Sensfuß et al., 2008; McConnell et al., 2013) including a rising incidence of negative price events (Antweiler and Muesgens, 2021), caused by legitimate needs to keep inflexible plant on the wires and/or distortive VRE subsidies that only paid on metered output. Merit order effects are complex and comprise various sub-components, viz. price impression effects (Edenhofer et al., 2013; Hirth, et al., 2016), stochastic production effects (Johnson and Oliver, 2019) and thermal plant utilisation effects (Simshauser, 2020). As the latter become more acute, coal plant exit becomes predictable (Rai and Nelson, 2020, 2021) and merit order effects can reverse in a cyclical response (Felder, 2011; Dodd and Nelson, 2019; Simshauser, 2020).

Moving beyond ~20% and through to ~50%, particularly in geographically diverse and sparsely populated networks like Australia's NEM, complex technical challenges emerge including system strength shortfalls (Qays *et al.*, 2023), deteriorating inertia (Newbery, 2021), sharply falling minimum loads and concerns over meeting reliability constraints given the prevalence of intermittent resources (Billimoria and Poudineh, 2019; Billimoria and Simshauser, 2023). The progressive loss of thermal dispatchable plant in earlier periods – at times in a disorderly manner – amplify these challenges (Dodd and Nelson, 2019).

One challenge which may occur throughout these mid- and later phases are entry frictions including post-entry VRE investment failures. Frictions constraining entry such as VRE project connection queues are becoming prominent (Millstein *et al.*, 2021; Seel *et al.*, 2023). Identifying and quantifying specific sources of post-entry investment failure is important to ensure any policy response is carefully designed and targeted in order to avoid creating a mass disruption event (Simshauser, 2021). In Australia's NEM, sources of investment failure include pre-commissioning connection lags and hold-point testing (Gohdes et al, 2023), movements in Marginal Loss Factors, (Simshauser and Gilmore, 2020; Simshauser, 2021), requirements to remediate system strength (Simshauser and Gilmore, 2022; Qays *et al.*, 2023) and rising levels of renewable 'curtailment' from either network congestion (McDonald, 2023), negative price events (Joskow, 2022) or excess supply (Newbery, 2023c).

Rising average rates of congestion indicate an increasingly constrained network. Adequacy of network hosting capacity and VRE *investment cycles* can be observed in other significant energy markets. The lead indicator of these cycles appears to be availability of network hosting capacity (Du and Rubin, 2018). The first VRE investment supercycle in ERCOT (Texas) centred either side of strategic anticipatory network investments in 345kV transmission lines forming Renewable Energy Zones. Subsequent investment cycles spanned a second REZ development period (Du, 2023). It is noteworthy that ERCOT VRE investment slowed in response to rising network congestion (i.e. a signal of an increasingly constrained network) while investment rates accelerated soon after additional anticipatory REZ network capacity commitments were made (Gowdy, 2022).

Creating new network capacity by building a REZ sends a strong locational signal to generation as 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 creation of a REZ is invariably designed to mitigate existing congestion (Du and Rubin, 2018; Du, 2023). Simshauser, Billimoria and Rogers (2022) outline how VRE can be co-optimised within a REZ but there has been far less analysis on 'marginal curtailment rates' (Newbery, 2021, 2023b, 2023a) – the focus of the subsequent quantitative analysis.

3. Models and Data

To assess the welfare implications of average and marginal curtailment rates we rely on two sequential models, i). a Project Finance or PF Model, and ii). a REZ Optimisation Model.

3.1 The Project Finance Model and Data

The PF Model is a conventional multi-period cash-flow program capable of simulating multiple generation technologies under a range of organisational structures and structured financing options. It produces generalised Levelized Cost of Electricity (LCoEs) estimates, with structured finance and taxation variables co-optimised within the model itself. Critical inputs appear in Tables 1 and 2. They are consistent with survey data of observed financial structures (Gohdes et al., 2022, 2023) along with relevant updates.

Table 1: PF Model technical parameters

Variable Renewable Energy		Wind	Solar
Project Capacity	(MW)	1,000	500
Overnight Capital Cost	($/kW)	2,800	1,600
Annual Capacity Factor	(%)	35.0%	26.5%
Expected Avg Curtailment	(ppt)	0 - 3	0 - 3
Auxillary Load	(%)	1.0%	1.0%
Fixed O&M	($/MW/a)	29,940	20,000
Variable O&M	($/MWh)	0.00	0.00
Ancillary Services Costs	(% Rev)	-1.0%	-1.0%
Transmission Losses	(MLF)	0.980	0.970
Aggregate REZ Charges*	($m pa)	17.4	7.6

* This fixed annual amount is divisible by the entire wind and solar fleet.

Source: Gohdes (2022, 2023).

We assume project financings split into 5-year Bullet (Term Loan 'B') and 7-year Amortising (Term Loan 'A') facilities – shorter dated (5-7 year) debt being the dominant tenor currently used in Australia.

Table 2: PF Model financial parameters

Renewable Project Finance		
Debt Sizing Constraints		
- DSCR	(times)	1.25
- Gearing Limit	(%)	0.8
- 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	(%)	3.95%
- Term Loan B Spread	(bps)	180
- Term Loan A Swap	(%)	4.05%
- Term Loan A Spread	(bps)	209
- Refinancing Rate	(%)	6.0%
Expected Equity Returns	(%)	8.0%

Source: Gohdes (2022, 2023), Bloomberg.

Because the full model logic is set out in Appendix I of Simshauser (2024), we propose not to reproduce the detail here. Suffice to say the model follows standard financial economics conventions.

3.2 REZ Optimisation Model and Data

Our REZ Optimisation comprises a structural LP Model of a double circuit 275kV REZ with multiple generator connections. Hourly intermittent wind and solar resource options are drawn upon for dispatch and limited by transmission line ratings. Critical variables for determining seasonal (or dynamic[4]) line transfer limits centre on conductor type and allowable operating temperatures under 'normal' and 'emergency' conditions.[5] This in turn leads to the following seasonal line ratings (50-200km from the coast):

Table 3: Seasonal Line Ratings (Amps)

	Normal Rating *NR* (Amps)	Emergency Rating *ER* (Amps)
Summer	1734	2582
Mild Seasons	1981	2774
Winter	2162	2922

Source: Simshauser (2024).

Seasonal power transfer capacity of a double circuit 275kV REZ in the peak summer period $\left(REZ_{t=Sum}^{S}\right)$ are identified in Eq.(1).

$$REZ_{t=Sum}^{S} = Min\left[\left(2 \cdot \sqrt{3} \cdot 0.275 \cdot NR_{t=Sum}^{S} \cdot 0.93\right), \left(\sqrt{3} \cdot 0.275 \cdot ER_{t=Sum}^{S} \cdot 0.93 + FCAS^{S}\right), \theta_{Sum}^{S}\right]. \quad (1)$$

[4] While the model comprises the detail necessary for dynamic line ratings (Simshauser, 2024) we have chosen seasonal ratings to simplify interpretation of results. Extension via dynamic ratings would make a logical extension of this article.

[5] For the case at hand, a reference twin-sulphur aluminium conductor is assumed with normal and emergency operating temperatures of 75º and 90º C, respectively.

In Eq.(1) the first term identifies Static seasonal (superscript 'S') thermal transfer capacity for each conductor for each of two circuits (2 x √3 x 0.275 x Current) operating at Normal Rating $NR^S_{t=Sum}$ during summer (subscript *t*=*Sum*) and converted to MW (assumed power factor of 0.93). The second term repeats the process for a single circuit operating at Emergency Rating $ER^S_{t=Sum}$ with a runback scheme enabled given the Frequency Control Ancillary Service $FCAS^S$ suite.[6] The third term θ^S_{Sum} is an exogenous constraint representing downstream fixed capacity limits. This produces the following maximum hourly power flow limits:

- Summer 2 x 768 MW = 1,534 MW
- Winter 2 x 958 MW = 1,916 MW
- Mild 2 x 878 MW = 1,756 MW

With line ratings established, the REZ Optimization Model seeks to maximise aggregate five-year wind and solar production or profit (as specified) subject to an array of constraints including power transfer limits and *'tolerable'* curtailment levels. Changes to producer and consumer welfare are quantified within the model. The model structure, which is largely based on Simshauser et al., (2022), is as follows.

Let $re \in RE$ be the set of wind and solar projects connecting to the REZ, each with installed capacity K_{re} and proportion of plant availability $\beta_{re,t}$. Let $t \in T$ be the set of dispatch intervals and $G_{re,t}$be output of generator re. At this point, the objective function becomes a relatively straight-forward one:

$$OBJ_{GEN} = Max\left(\sum_{t \in T} \sum_{re \in RE} G_{re,t}\right), \tag{2}$$

S.T.

$$G_{re,t} \leq K_{re} \cdot \beta_{re,t} \; \forall \, re \in RE, t \in T, \tag{3}$$

$$\sum_{re \in RE} G_{re,t} \leq REZ^S_{t=Sum} \; \forall t \in T, \tag{4}$$

$$\sum_{re \in RE} G_{re,t} \geq (1 - \delta_{re}) \cdot E\left(G_{re,t}\right). \tag{5}$$

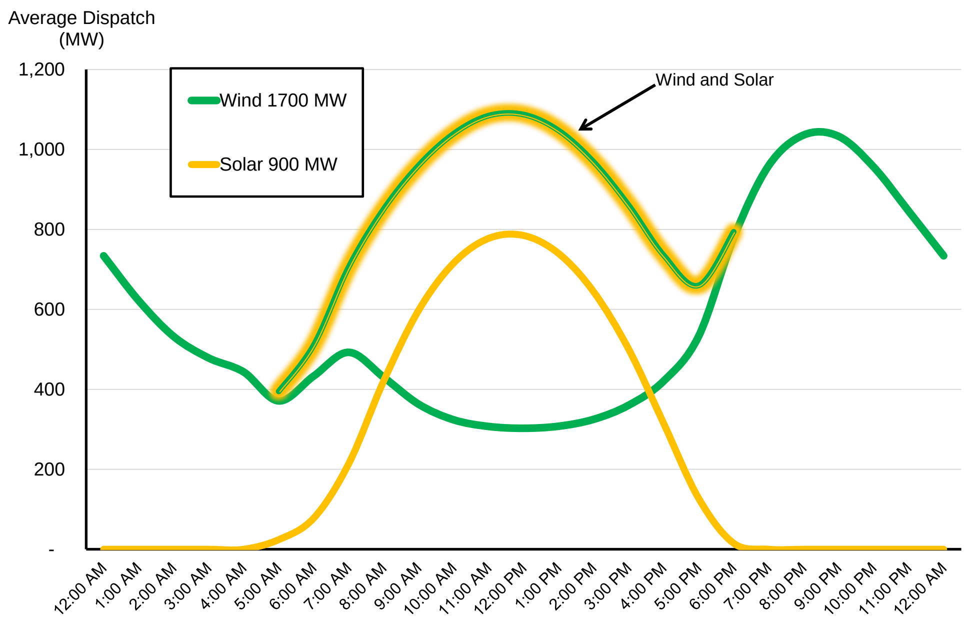
Eq.(2) sets the Objective Function noting the variable can switch between Production and Profit, as specified. Eq.(3) limits generation to available capacity $K_{re,t}\beta_{re}$ while Eq. (4) constrains total generation in each dispatch interval $t \in T$ to transmission line transfer limits in accordance with Eq. (1). Eq.(5) ensures the adverse impacts of line congestion and subsequent wind and solar curtailment (δ_{re}) impacting expected output $E\left(G_{re,t}\right)$ do not exceed tolerable limits associated with contemporary project financings. This latter constraint can be thought of as the minimum generation output $\left(\sum_{re \in RE} G_{re,t}\right)$ required for project financing.

[6] Australia's NEM enables FCAS duties in a largely dynamic process driven by the single largest credible contingent event. Under normal system conditions this is typically the largest spinning generation unit (Kogan Creek) which is rated at ~750MW.

The model draws on hourly VRE resource options using five-year historic ata (2017-2021) for a given geographic location. Queensland's resource-rich Western Downs area has been selected with real-time weather re-analysis data for solar and wind resources drawn from Gilmore et al., (2022). The diurnal pattern of wind and solar from Queensland's Western Downs are complementary (see Fig.1). The relative pattern of wind is biased to evenings, with the middle of the day characterised by hot, relatively still, sunny conditions at which time solar PV output reaches its maximum. The 'seasonal average' correlation between wind and solar production in Fig.1 is -0.71 (mild seasons = -0.75, winter = -0.69) noting hourly data over five-years naturally exhibits much greater variability with a -0.28 correlation.

This complementarity between wind and solar helps explain the intuition behind subsequent model results – an *a priori* expectation that optimised wind and solar PV capacity connecting to a transmission line with 1,536MW of (summer) transfer capacity will evidently exceed 1,536MW. In Fig.1, average production from 900MW of solar sits within the average output from 1,700MW of wind – given the diurnal diversity of average output. However, only high-resolution (hourly) modelling can reveal the true extent of this diversity.

Figure 1: Average Summer Production for Wind and Solar PV (2017-2021)



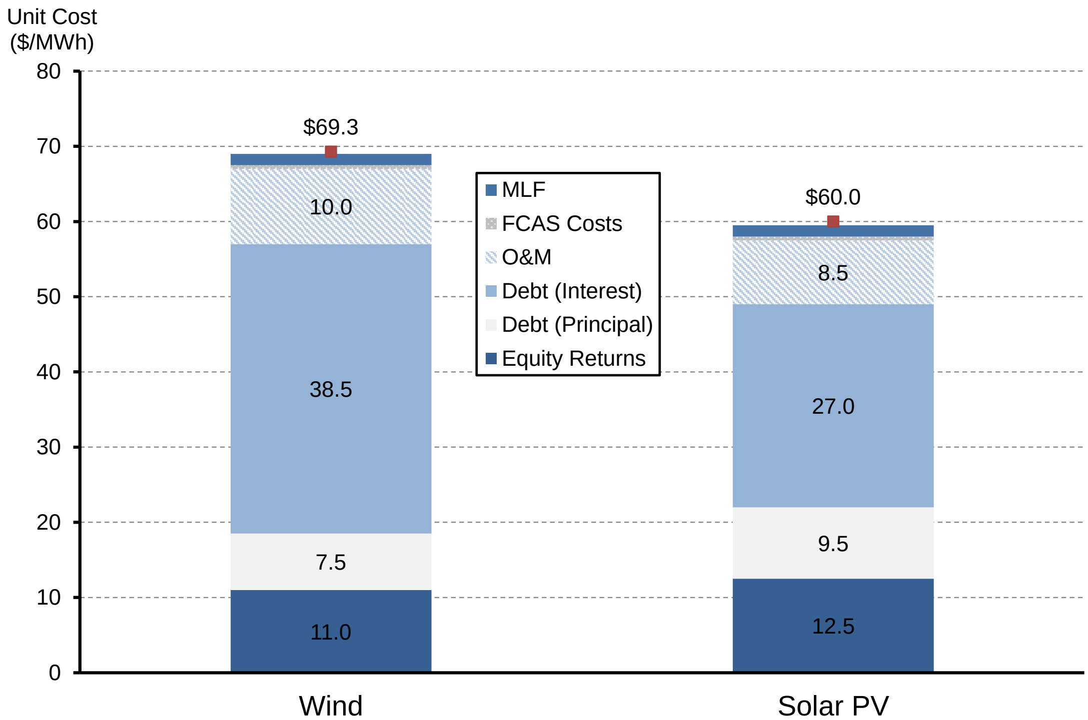
4. Model Results

Our analytical sequence commences by defining entry costs for wind and solar PV. We then define optimal levels of wind and solar capacity given REZ transfer limits set out in Section 3.2. We then compare average and marginal curtailment rates for each plant type under ever expanding levels new entrant capacity and REZ line congestion, with an objective of seeking welfare maximising results.

4.1 PF Model Results – Entry Costs

Our PF Model derives entry costs (i.e. the LCoE) of A$69.3/MWh (wind) and A$60/MWh (solar PV) in an unconstrained state as illustrated in Fig.2. Table 1 cost inputs were based on a 1,000MW wind farm and a 500MW solar array. Our modelling assumes perfect capacity divisibility at a constant cost per MW.

Figure 2: Entry Costs – Wind & Solar PV



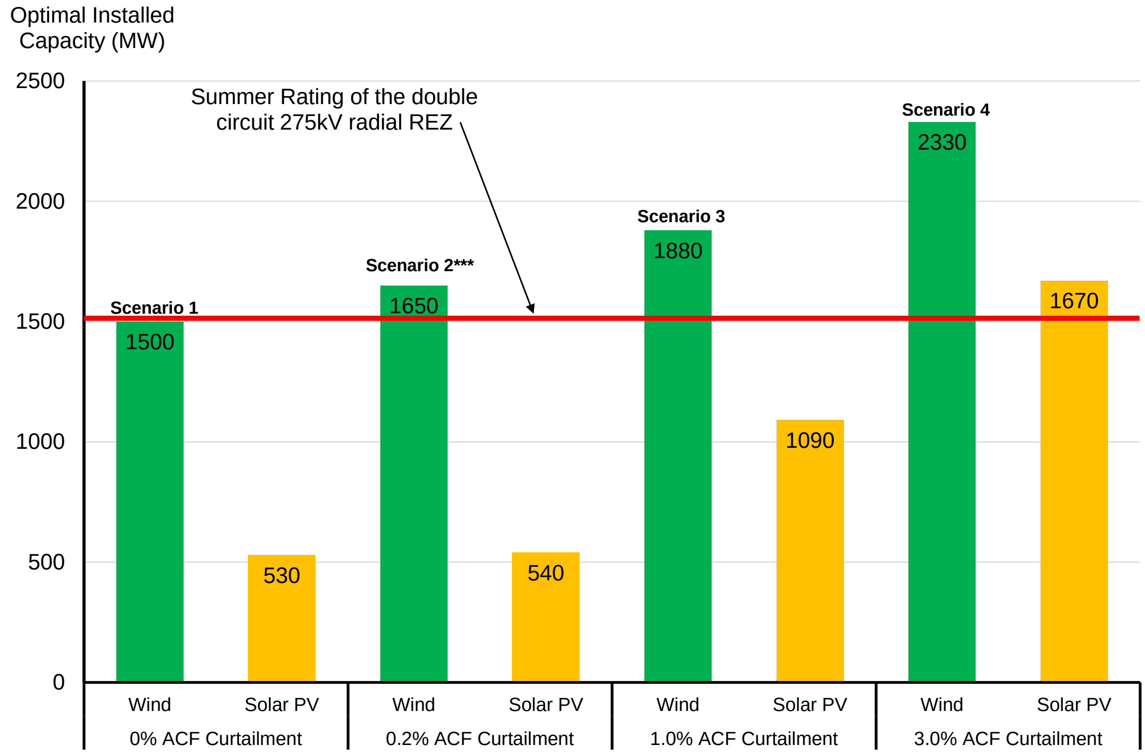
Note: MLF = Marginal Loss Factor

4.2 REZ Optimisation Model Results – optimal mix of wind and solar

The next step in our modelling sequence is to identify the optimal mix of wind and solar PV plant capacity that maximises aggregate final output (Section 4-5) and profit (Section 6) over the five-year period 2017-2021 given power transfer limits (constrained by Eq. 4) and 'tolerable' levels of curtailment (constrained by Eq. 5).

In the REZ Optimisation Model, we begin by identifying four 'max production' scenarios – three of which are distinguished by Eq.5 congestion variable (δ_{re}) – set to 0%, 1% and 3% in Scenarios 1, 3 and 4, respectively. 'Scenario 2***' is set to maximise the *Economic Profits* of connected generators given prevailing spot prices (explained later in Section 6) which has a curtailment rate of 0.2%. Results are illustrated in Fig.3.

Figure 3: Optimal Mix of Wind and Solar PV at differing Curtailment Rates



In Scenario 1, the congestion constraint is set to near zero ($\delta_{re}^{re} < 0.1\%$) with wind and solar simultaneously co-optimised. In the dispatch process, there is no priority for either technology over the other and *potential output* equals *practical output* since there is near zero curtailment. The Model returns 1,500MW of wind (35.0% ACF) and 530MW of solar (26.5% ACF). Scenario 2*** will be dealt with in Section 6 – noting it sought to maximise economic profit.

Scenarios 3 and 4 maximise production with the congestion constraint set variously ($\delta_{re} = 1\%, 3\%$). Given no priority for one technology over the other, when potential production output exceeds transmission line capacity REZ_t^S, VRE output is curtailed on a production-weighted, equalised basis until the sum of instantaneous aggregate output $\sum_{re \in RE} G_{re,t}$ meets the constraint set out in Eq. 4. This leads to very different results to Scenario 1.

In Scenario 3, wind increases to 1,880MW and solar PV to 1090MW. As an aside, aggregate five-year output in Scenario 3 (40,200GWh) is materially higher than Scenario 1 (29,100GWh). Aggregate final production in Scenario 4, at a 3% average curtailment rate, is higher again at 49,900GWh.

If decarbonisation targets are ambitious but REZ network capacity is a scarce resource due to community limits to the extent of transmission line development, we should anticipate that installed generating capacity will be sized to stress the nominal REZ transmission line transfer limits. Thus far we have only examined average curtailment rates. The difference between average and marginal curtailment rates is of utmost importance and its consequential impacts on long-run average and marginal (renewable entry) costs and prices therefore requires examination.

5. Average vs. marginal curtailment

Understanding network congestion risk is central to VRE investment in the mid- to late-stages of the renewable transition because the incidence, prominence and financial impact of curtailment rates can be expected to rise. Over time, storage and flexible loads may provide a counterweight, but any interim period is likely to be characterised by rising curtailment rates.

5.1 Principles

Consider the following simple assessment of the Queensland power system using Pollitt & Anaya's (2016) analogy. Maximum demand is ~10GW with aggregate final energy demand of 60TWh pa. To meet reliability constraints, historically, a thermal plant stock of 11.2GW would be required. Since average demand is 6.8GW, fleet-wide utilisation was ~61% (i.e. 6.8GW/11.2GW).

Now consider the same system with 50% renewables. The capacity factor of Queensland's 5.4GW of rooftop Solar PV is ~14.6%, and utility-scale wind and solar ACFs average ~35% and ~28% respectively. To meet 30TWh renewable market share, 6.0GW of wind and 4.5GW of solar PV needs to be added to the 5.4GW rooftop solar. Coincident output from this 15.9GW renewables fleet will likely range from ~1 to ~11.0GW.

We therefore have a situation where 59% (15.9/[11.2+15.9]) of plant capacity is intermittent, and potential VRE output could be as much as 200% (11.0/6.8) of average system demand, or as little as 15% (1.0/6.8). Thermal plant utilisation would fall from 61% to 32%, testing their technical and economic limits. Further, 11.0GW of simultaneous 'potential' renewable output is not viable given 6.8GW of average system demand – and thus wind and solar plant will be curtailed during mismatches. Batteries and pumped hydro storage will serve to delay curtailment rates but VRE entry currently exceeds storage entry.

5.2 Model Results

We have populated the REZ Optimisation Model with 1,400MW of wind and 520MW of solar PV to commence simulation iterations in an unconstrained state. In an iterative routine, we then simulate Optimisations #1 and #2, as follows:

1. Holding solar PV constant at 520MW, wind capacity is raised in 10MW increments from 1,400MW through to 3,300MW (see Fig.4a).

2. Holding wind constant at 1,400MW, solar capacity is then raised in 10MW increments from 520MW through to 2,520MW (see Fig.4b).

Optimisation #1 results (Fig.4a) start with the x-axis measuring installed wind capacity (MW) and the y-axis measuring plant Annual Capacity Factors (%). Starting at the origin, installed capacity is 1,400MW and the *Practical Average* (i.e. dispatchable) ACF equates to 35% - exactly equal to the potential ACF of 35%. As wind plant capacity progressively increases from 1,400MW to 3,300MW along the x-axis, the wind fleet Practical Average ACF begins to deteriorate from 35% down to 29.5% - depicted by the falling solid dark blue line. The commensurate fleet-wide *average curtailment rate* is depicted by the rising solid light blue line, which increases from 0% Average ACF Curtailment to 5.5%. These are the average curtailment results for given levels of REZ-connected wind capacity (i.e. 35% ACF – 29.5% ACF = 5.5% average curtailment rate).

Figure 4: Optimisation #1 – Average vs Marginal Curtailment - Wind

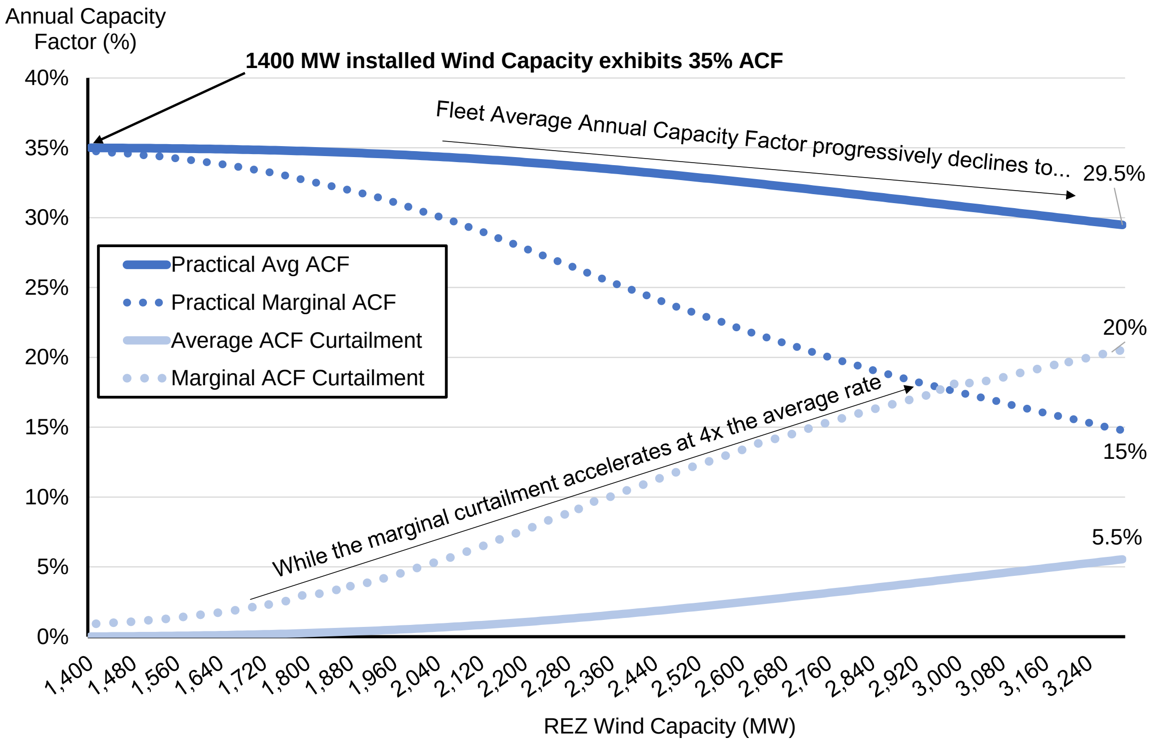
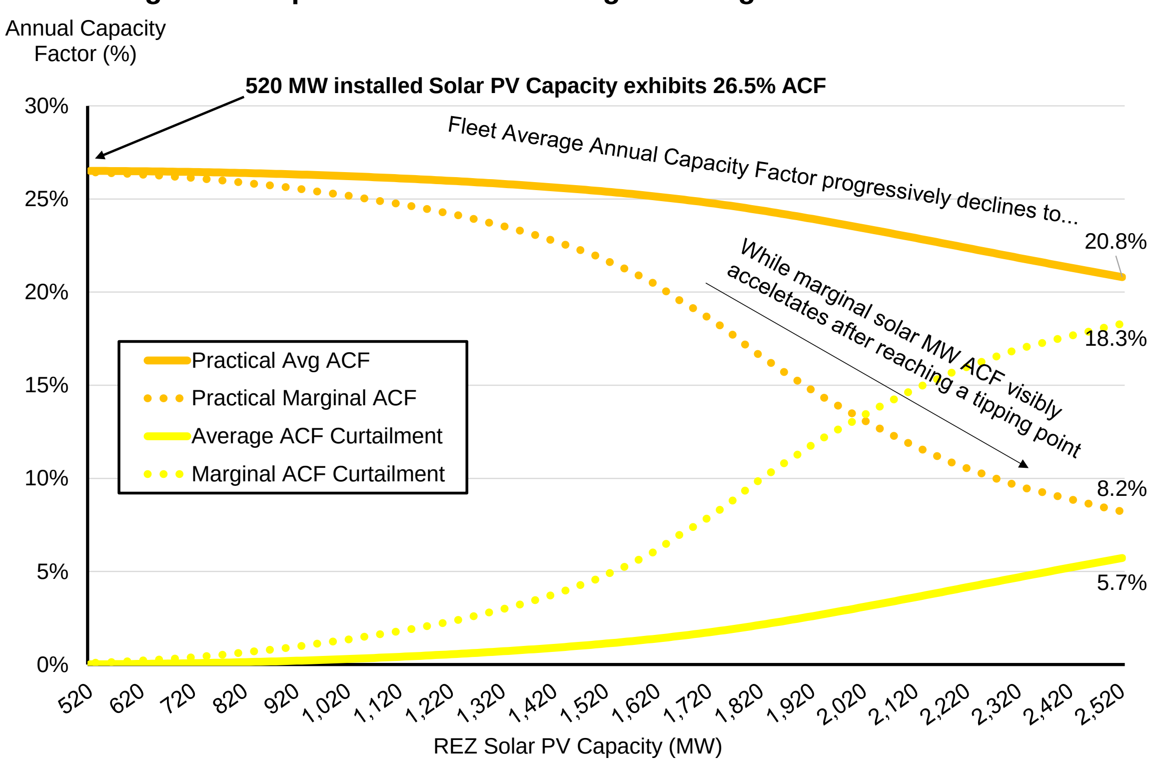


Figure 4b: Optimisation #2 – Average vs Marginal Curtailment – Solar PV



Now consider the marginal MW installed, represented by the two dotted lines. Once installed wind capacity reaches ~1,500MW on the x-axis, marginal curtailment commences more visibly (dotted dark blue line) than the average curtailment line (solid dark blue line). By the 2000MW mark on the x-axis, marginal curtailment equates to 5% yet the average curtailment rate is barely visible at the same point. As each incremental MW of wind is added, marginal curtailment rises sharply. Indeed, the dotted dark blue line shows the final 10 MW installed (i.e. from 3,290MW to 3,300MW) achieves a Practical Marginal ACF of just 15% with a commensurate Marginal ACF Curtailment rate of 20% (i.e. 35% Potential ACF – 15% Practical ACF = 20% marginal curtailment rate). Put another way, the last 10MW installed produces less than 40% of the first 10 MW installed. Above all, the marginal curtailment rate is almost 4x the average (i.e. 20% vs 5.5%).

Optimisation #2 is presented in Fig.4b. Here, wind is held constant at 1,400MW while solar increases from 520MW to 2,520MW in 10MW increments along the x-axis. Results in Fig.4b are broadly consistent with those in 4a with one important difference. The stochastic nature of wind output occurs across a 24-hour period, and it is rare that maximum wind output is reached and sustained throughout the year. For example, our data reveals a 1000MW wind farm would produce 950+ MW throughout an hourly trading interval on just 73 occasions (i.e. 73hrs of 8,760hrs pa) or 0.8% of productive hours. Conversely, at least 400hrs pa will exceed 950MW of solar output out of the ~4900hrs of daylight pa (i.e. 8.1% of productive hours). Consequently, given greater predictability of reaching maximum production output, we should anticipate solar reaches a 'congestion tipping point' faster, thereafter experiencing a more aggressive downward marginal trajectory (absent localised storage).

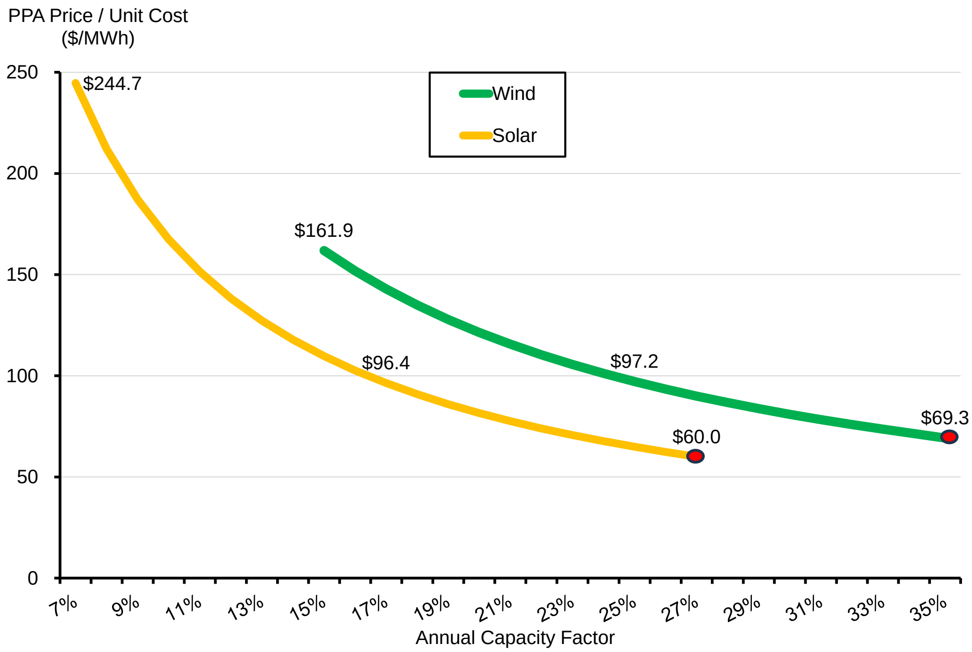
6. Long Run Average Cost vs. Marginal Cost

The stark contrast between average and marginal curtailment rates in Fig.4 Optimisations #1 and #2 has material ramifications for transmission access, the cost of new entrant plant, producer profits, consumer prices and welfare. Before examining these impacts, we re-run the PF Model to simulate entry costs given the range of curtailment rates observed in Fig.4.

6.1 PF Model Results – Curtailment Entry Costs

The PF Model has been re-run on an iterative basis using the assumptions set outlined in Tables 1-2 but with continuously adjusting ACFs, noting the assumption of perfect divisibility. Simulations have been iterated from 15-35% ACF for wind, and 8-26.5% for solar PV with results illustrated in Fig.5. The red marker highlights unconstrained production.

Figure 5: PF Model: Plant Long Run Marginal Costs



6.2 Model results: priority access vs non-firm access

To complete our analysis of average and marginal curtailment rates, we quantify the welfare impacts of changing from *non-firm access* to an alternate *priority access* regime in a multi-zonal, energy-only gross pool electricity market setup. For clarity, the NEM's existing Connection and Access arrangements operate under a *'non-firm, open access'* regime. In a practical sense, this means VRE investors, not consumers, face the risk of curtailment. Because access is non-firm, the burden of curtailment in a common network area is shared amongst VRE generators[7] who therefore face the set of *average curtailment rate* curves shown in Fig.4.

To clarify, the first VRE project in an otherwise 'under-subscribed REZ' (up to ~1500MW installed capacity) in Australia's NEM will not be initially subjected to curtailment. But as more and more wind and solar projects enter and populate the REZ, all local VRE generators – incumbent and new entrants alike – will share the rising burden of curtailment (i.e. average curtailment rates) given the limits of REZ network transfer capacity. Furthermore, it is NEM convention that reference quantities in PPAs and CfDs are for 'exported energy' and consequently, there are no consumer-funded side-payments for curtailed energy. In the NEM, the risk of curtailment is borne entirely by producers (VRE investors), not consumers.

In contrast, switching to a *priority access* regime shifts the trajectory of VRE plant along the set of *marginal curtailment rate* curves in Fig.4. The reason for this is axiomatic – the first entrant has a form of synthetic access right to dispatch within the REZ. Subsequent entrants therefore access *residual REZ transmission line transfer capacity*, which in turn is represented by the set of marginal curtailment rate curves. As the subsequent analysis reveals, this has very material – and adverse – effects for

[7] Within a REZ curtailment would be shared subject to offer prices submitted to the market operator. There is a nuance to this downstream from a REZ because NEM's dispatch engine has a representation of the transmission system and associated constraints. Consequently, locational coefficients may alter this outcome at a broader system level – an issue we highlight in our concluding remarks.

consumers in a multi-zonal, energy-only, gross pool electricity market set-up like the NEM.

To undertake the comparative analysis, we combine Fig.5 entry costs, hourly spot price data (2017-2021) from the Queensland region, and the regression estimates from Gonçalves and Menezes' (2022) analysis of NEM merit order effects arising from the entry of wind and solar[8]. These latter coefficients are used to dynamically adjust historic spot prices within the REZ Optimisation Model as wind and solar plant capacity is varied. Time-stamped historic renewable resources and spot prices are appropriately matched by hour, with the half-hourly regression coefficients from Gonçalves and Menezes (2022) matched to hourly spot prices (see Appendix I).

The historic period 2017-2021 was selected due to the rich diversity of market dynamics that occurred within the NEM. This included the entry of ~12.5GW of solar PV, 10+GW of rooftop solar PV, 10GW of wind and the exit of the 1600MW Hazelwood coal-fired power station. In the Queensland region, renewable market shares rose from 5% to 20%, rooftop solar increased from 1.7GW to 4.5GW and a catastrophic failure of a baseload 440MW coal unit occurred during 2021. Consequently, this period captures an energy market business cycle (see Arango and Larsen, 2011; Cepeda and Finon, 2011; Bublitz et al., 2019) that comprises rapid entry, accelerating but differential *merit order effects* (Mills et al., 2012; Bushnell and Novan, 2021; Gonçalves and Menezes, 2022), followed by *rebound effects* from 2021 (see Felder, 2011; Hirth, 2013, 2015; Simshauser, 2020).

A statistical summary of spot prices is provided in Table 4. Note at Line 1 the annual Time Weighted Average spot price varies from A$41.3 to A$102.5 with a five-year average of A$75.6/MWh. For wind, dispatch-weighted average prices are *primarily above* 100% (Line 3) whereas solar is *primarily below* 100% (Line 5). Of significance is the rising Hours of negative price events, at Line 8.

Table 4: Statistical summary of Queensland spot prices (2017-2021)

	Spot Prices		2017	2018	2019	2020	2021	Total
1	Time Weighted Average	($/MWh)	102.5	74.8	71.8	41.3	87.7	75.6
2	Wind Dispatch Weighted	($/MWh)	97.5	76.5	74.7	44.0	90.4	76.4
3	Wind % of Average Spot	(%)	95%	102%	104%	107%	103%	101%
4	Solar Dispatch Weighted	($/MWh)	109.8	71.4	65.0	37.1	56.6	69.4
5	Solar % of Average Spot	(%)	107%	95%	90%	90%	65%	92%
6	95th Percentile Price	($/MWh)	47.9	46.7	28.9	4.7	-4.9	18.4
7	5th Percentile Price	($/MWh)	147.4	125.4	127.4	78.9	194.4	134.7
8	Negative Price Events	(Hrs)	13	14	141	338	517	1,023
9	Coefficient of Variation*		2.8	0.5	0.6	1.2	4.2	2.8
10	Kutosis		634	358	532	309	637	1,568
11	Skewness		23	14	10	14	22	34
12	Mininum Spot Price	($/MWh)	-176	-143	-674	-546	-1,000	-1,000
13	Maximum Spot Price	($/MWh)	10,618	1,289	2,145	1,275	15,000	15,000
	* Coefficient of Variation based on hourly data (Std Dev / Time Weighted Average)							

[8] To summarise, +1GW of wind capacity results in a -$0.3/MWh reduction to average annual prices, and -$0.46/MWh reduction from solar (or -$0.79/MWh in solar periods). Evening periods experience a mild increase (see Appendix I).

The REZ Optimisation Model iteration process for this final scenario - the purpose of which is to compare open access and priority access - differs from those presented in Section 6.1 in one important respect. In Optimisations #1-2 (in Section 6.1), the installed capacity of one technology (e.g. solar) was held constant while the other (e.g. wind) was increased in 10MW increments. In this final scenario, wind and solar PV start at 1,400MW and 520MW per Section 6.1, but both technologies are *simultaneously increased* in capacity by their volume-weighted output, that is, +8.3MW increments for wind and +1.7MW increments for solar PV (each iteration continues to rise by 10MW increments). Furthermore, the focus of Section 6.1 was average and marginal output. In the present analysis, our focus changes to average and marginal costs and revenues, along with an assessment of changes in welfare.

Results for Optimisation #3, whereby the model iterates wind and solar simultaneously, appear in Fig.6a (wind) and 6b (solar). The output in both charts comprises Long Run Average Cost and Revenue curves, and Long Run Marginal Cost and Revenue curves. The *non-firm open access* regime, whereby curtailment is a shared burden, is represented by the Average Cost and Revenue curves. In contrast, *priority access* is represented by the Marginal Cost and Revenue curves. Interpretation of results is as follows.

Starting with Fig.6a, note the “Long Run Average Cost – Wind” curve (thick black line) commences at the PF Model’s preferred result of A$69.3/MWh which is consistent with a wind project operating unconstrained at 35% ACF (recall this is the same result in Fig.2 and Fig.5). The shape of the average cost curve, which reflects non-firm access, has a gentle slope which essentially reflects the *average curtailment rates* of Fig.4a. While not visible in Fig.6a, the associated ACFs along the x-axis run from 35% (at 1,400MW wind installed) through to 31.5% (at 2,800MW of wind installed). Consequently, the average cost curve spans the range A$69.3/MWh to ~A$78.5/MWh – in line with ACF and unit cost results reported in Fig.5. The ‘Average Revenue – Wind’ curve crosses at 2,300MW – this being the equilibrium result given market prices.

The “Long Run Marginal Cost – Wind” curve (thick light grey line) also commences at A$69.3/MWh but rises sharply. This is because it represents priority access, which therefore reflects the *marginal curtailment rate curves*. The y-axis has been truncated at A$120, and by 2,650MW the unit cost equates to A$120/MWh. Again while not visible, the associated ACFs for this curve runs from 35% (at 1,400MW) through to 20% (at 2,650MW). The sharp contrast between the wind fleet’s Long Run Average Cost (solid black line) and Long Run Marginal Cost (solid light grey line) is evident. So too is the difference between Average and Marginal Revenue curves arising from spot prices over the period 2017-2021. Once again, the difference between the two curves is that average revenues reflect non-firm arrangements where all connected generators share the burden of curtailment. With priority access, the marginal entrant bears the entire burden of any incremental curtailment, and therefore earns dramatically less revenue than earlier, prioritised entrants. Consequently, the ‘Marginal Revenue – Wind’ curve crosses at 1,650MW given market prices.

These same results are replicated for solar PV in Fig.6b. The key point to note is that equilibrium vis-à-vis non-firm access is 860MW of solar, whereas priority access represented by the marginal cost and revenue curves settles at 540MW. The full set of yearly and 5-year aggregate results for generation capacity, dispatch weighted prices, production output and profit results are presented in Table 5 (non-firm access, average curtailment) and Table 6 (priority access, marginal curtailment).

Figure 6: Long Run Average vs. Marginal Cost (Wind Fleet)

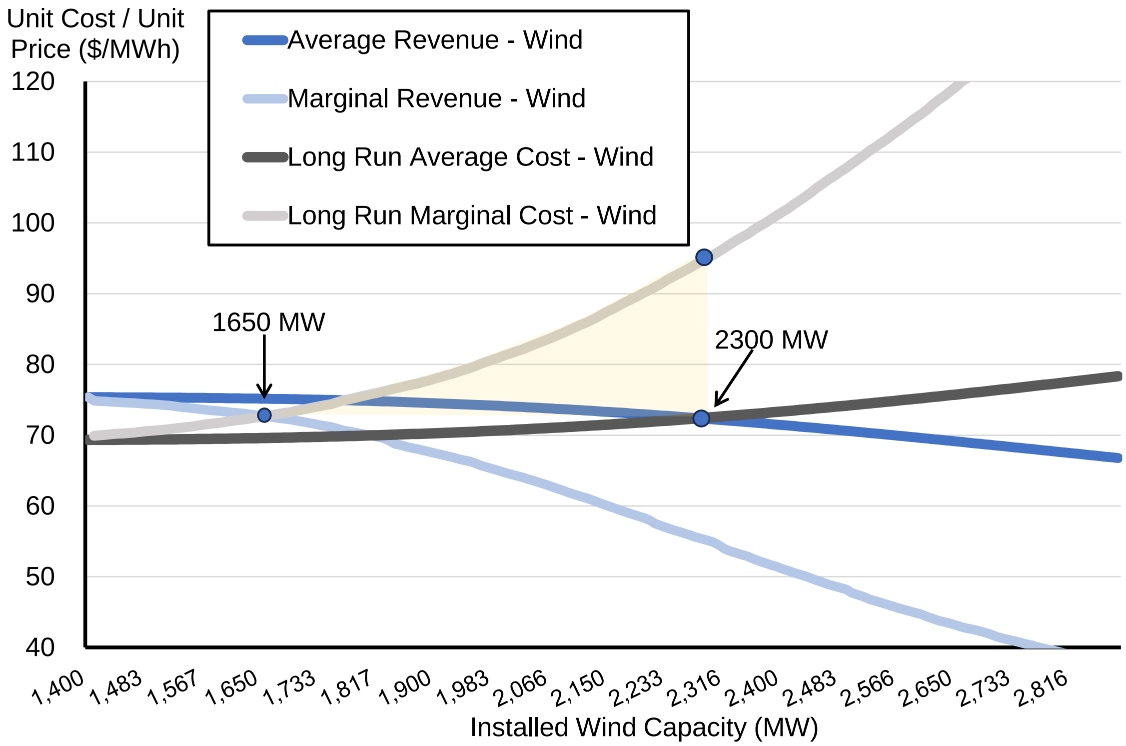
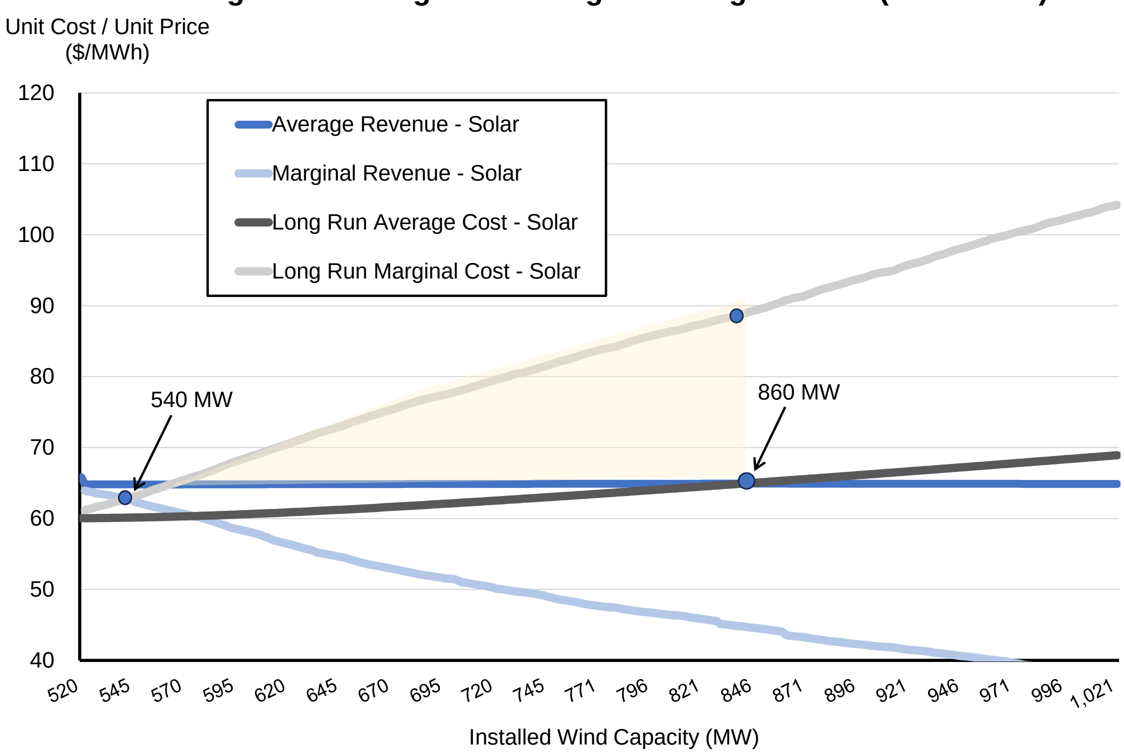


Figure 6b - Long Run Average vs. Marginal Cost (Solar Fleet)



Note that the Table 5 results are for the optimal 2,300WM of wind and 860MW of solar in equilibrium for the non-firm access case. Here, *Economic Profits* are zero (or near-zero) across the REZ-connected VRE portfolio as identified through results at Lines 6, 36 and 42 of Tab.5. Wind energy curtailed is ~5% of total production (see Line 4) with a wind fleet-wide average ACF of 32.6% (Line 11) cf. potential ACF of 35% (Line 10). For solar PV, 4.3% of energy is curtailed (Line 24) producing a solar fleet-wide average ACF of 23.7% (Line 31) compared to the potential ACF of 26.5% (Line 30). As a separate aside, REZ charges average ~A$3/MWh (see Lines 19 and 39).

Table 5: Equilibrium results (average curtailment / open access)

	Wind	2,300 MW	2017	2018	2019	2020	2021	TOTAL
1	Potential Wind Output	(GWh)	6,549	7,533	7,138	7,056	7,000	35,276
2	Practical Wind Output	(GWh)	6,263	7,054	6,731	6,759	6,689	33,496
3	REZ Congestion	(GWh)	286	479	407	297	312	1,780
4	Energy Curtailed	(% of Prod)	4.4%	6.4%	5.7%	4.2%	4.5%	5.0%
5	Economic Wind Output	(GWh)	6,256	7,046	6,663	6,554	6,368	32,887
6	Spill -ve spot prices	(GWh)	8	8	68	204	320	609
7	Energy Spilled	(%)	0	0	0	0	0	0
8	Total Curtail & Spill	(GWh)	294	487	475	502	632	2,389
9	Total Curtail & Spill	(% of Prod)	4.5%	6.5%	6.7%	7.1%	9.0%	6.8%
10	Potential ACF	(% - ACF)	32.5%	37.4%	35.4%	35.0%	34.7%	35.0%
11	Economic ACF	(% - ACF)	31.0%	35.0%	33.1%	32.5%	31.6%	32.6%
12	ACF Loss	(% - ACF)	1.5%	2.4%	2.4%	2.5%	3.1%	2.4%
13	Revenue	$m	611.0	542.6	505.3	294.3	588.4	2,541.6
14	Costs	$m	488.9	488.9	488.9	488.9	488.9	2,444.6
15	REZ Charges	$m	19.4	19.4	19.4	19.4	19.4	97.2
16	Economic Profit	$m	102.6	34.3	-3.0	-214.1	80.0	-0.2
17	Unit Revenue	($/MWh)	97.7	77.0	75.8	44.9	92.4	77.3
18	Unit Cost	($/MWh)	78.2	69.4	73.4	74.6	76.8	74.3
19	REZ Cost	($/MWh)	3.1	2.8	2.9	3.0	3.1	3.0
20	Economic Profit	($/MWh)	16.4	4.9	-0.5	-32.7	12.6	-0.0
	Solar PV	**860 MW**	2017	2018	2019	2020	2021	TOTAL
21	Potential Solar Output	(GWh)	2,006	2,053	2,043	1,956	1,935	9,993
22	Practical Solar Output	(GWh)	1,944	1,931	1,949	1,885	1,852	9,560
23	REZ Congestion	(GWh)	63	122	94	71	83	432
24	Energy Curtailed	(% of Prod)	3.1%	6.0%	4.6%	3.6%	4.3%	4.3%
25	Economic Solar Output	(GWh)	1,941	1,925	1,855	1,668	1,532	8,921
26	Spill -ve spot prices	(GWh)	3	6	94	216	321	640
27	Energy Spilled	(%)	0	0	0	0	0	0
28	Total Curtail & Spill	(GWh)	65	128	188	288	403	1,072
29	Total Curtail & Spill	(% of Prod)	3.3%	6.2%	9.2%	14.7%	20.8%	10.7%
30	Potential ACF	(% - ACF)	26.6%	27.3%	27.1%	26.0%	25.7%	26.5%
31	Economic ACF	(% - ACF)	25.8%	25.6%	24.6%	22.1%	20.3%	23.7%
32	ACF Loss	(% - ACF)	0.9%	1.7%	2.5%	3.8%	5.4%	2.8%
33	Revenue	$m	215.6	138.2	123.3	63.7	88.8	629.5
34	Costs	$m	119.9	119.9	119.9	119.9	119.9	599.6
35	REZ Charges	$m	5.6	5.6	5.6	5.6	5.6	27.8
36	Economic Profit	$m	90.1	12.7	-2.2	-61.8	-36.7	2.2
37	Unit Revenue	($/MWh)	111.1	71.8	66.4	38.2	58.0	70.6
38	Unit Cost	($/MWh)	61.8	62.3	64.6	71.9	78.3	67.2
39	REZ Cost	($/MWh)	2.9	2.9	3.0	3.3	3.6	3.1
40	Economic Profit	($/MWh)	46.4	6.6	-1.2	-37.1	-23.9	0.2
41	Portfolio Output (Line 5+25)	(GWh)	8,197	8,971	8,518	8,223	7,900	41,808
42	Portfolio Profit (Lines 6+36)	$m	192.8	47.0	-5.2	-275.9	43.3	1.9

Table 6 illustrates equilibrium results for priority access (i.e. marginal curtailment), which comprises an optimal 1,650MW of wind and 540MW of solar in equilibrium. Under priority access, Economic Profits are mildly positive reflecting the fact that entry costs are lower than prevailing prices, and curtailment is considerably lower at 0.4% for both wind (Line 4) and solar (Line 24) with ACF losses for wind of 0.8% (Line 12) and 1.9% for solar (Line 32). REZ costs rise from ~A$3/MWh (Tab.5, Lines 19 and 39) to ~A$4.25/MWh (Tab.6, Lines 19 and 39).

Table 6: Equilibrium results (marginal curtailment / priority access)

	Wind	**1,650 MW**	2017	2018	2019	2020	2021	TOTAL
1	Potential Wind Output	(GWh)	4,698	5,404	5,121	5,062	5,022	25,307
2	Practical Wind Output	(GWh)	4,685	5,371	5,101	5,048	5,006	25,211
3	REZ Congestion	(GWh)	13	33	20	14	16	95
4	Energy Curtailed	(% of Prod)	0.3%	0.6%	0.4%	0.3%	0.3%	0.4%
5	Economic Wind Output	(GWh)	4,680	5,365	5,043	4,884	4,737	24,708
6	Spill -ve spot prices	(GWh)	6	6	58	164	269	503
7	Energy Spilled	(%)	0	0	0	0	0	0
8	Total Curtail & Spill	(GWh)	19	39	78	178	285	599
9	Total Curtail & Spill	(% of Prod)	0.4%	0.7%	1.5%	3.5%	5.7%	2.4%
10	Potential ACF	(% - ACF)	32.5%	37.4%	35.4%	35.0%	34.7%	35.0%
11	Economic ACF	(% - ACF)	32.4%	37.1%	34.9%	33.8%	32.8%	34.2%
12	ACF Loss	(% - ACF)	0.1%	0.3%	0.5%	1.2%	2.0%	0.8%
13	Revenue	$m	460.5	415.3	382.4	219.9	433.7	1,911.9
14	Costs	$m	350.8	350.8	350.8	350.8	350.8	1,753.8
15	REZ Charges	$m	20.0	20.0	20.0	20.0	20.0	100.2
16	Economic Profit	$m	89.7	44.5	11.7	-150.9	62.9	57.9
17	Unit Revenue	($/MWh)	98.4	77.4	75.8	45.0	91.6	77.4
18	Unit Cost	($/MWh)	75.0	65.4	69.6	71.8	74.0	71.0
19	REZ Cost	($/MWh)	4.3	3.7	4.0	4.1	4.2	4.1
20	Economic Profit	($/MWh)	19.2	8.3	2.3	-30.9	13.3	2.3
	Solar PV	**540 MW**	2017	2018	2019	2020	2021	TOTAL
21	Potential Solar Output	(GWh)	1,260	1,289	1,283	1,228	1,215	6,275
22	Practical Solar Output	(GWh)	1,256	1,280	1,277	1,225	1,210	6,247
23	REZ Congestion	(GWh)	4	10	6	3	5	28
24	Energy Curtailed	(% of Prod)	0.3%	0.7%	0.5%	0.3%	0.4%	0.4%
25	Economic Solar Output	(GWh)	1,254	1,276	1,215	1,084	996	5,825
26	Spill -ve spot prices	(GWh)	2	4	61	141	214	422
27	Energy Spilled	(%)	0	0	0	0	0	0
28	Total Curtail & Spill	(GWh)	5	13	67	144	219	450
29	Total Curtail & Spill	(% of Prod)	0.4%	1.0%	5.3%	11.8%	18.0%	7.2%
30	Potential ACF	(% - ACF)	26.5%	27.1%	27.0%	25.8%	25.5%	26.4%
31	Economic ACF	(% - ACF)	26.4%	26.8%	25.6%	22.8%	20.9%	24.5%
32	ACF Loss	(% - ACF)	0.1%	0.3%	1.4%	3.0%	4.6%	1.9%
33	Revenue	$m	139.0	92.1	80.6	41.3	57.6	410.6
34	Costs	$m	75.3	75.3	75.3	75.3	75.3	376.5
35	REZ Charges	$m	5.0	5.0	5.0	5.0	5.0	24.8
36	Economic Profit	$m	58.7	11.8	0.4	-39.0	-22.7	9.3
37	Unit Revenue	($/MWh)	110.8	72.2	66.3	38.1	57.9	70.5
38	Unit Cost	($/MWh)	60.0	59.0	62.0	69.5	75.6	64.6
39	REZ Cost	($/MWh)	4.0	3.9	4.1	4.6	5.0	4.3
40	Economic Profit	($/MWh)	46.8	9.3	0.3	-35.9	-22.8	1.6
41	Portfolio Output (Line 5+25)	(GWh)	5,934	6,641	6,258	5,967	5,732	30,533
42	Portfolio Profit (Lines 6+36)	$m	148.4	56.3	12.0	-189.8	40.3	67.2

6.3 Welfare analysis

What REZ, and indeed broader zonal market outcome, might prevail in the NEM given the existing non-firm, open access regime? And how might this change if it were altered to a *priority access* regime?

The existing non-firm access regime implies equal dispatch rights for all connected generators in a REZ with production-weighted pro-rata sharing of curtailment, consistent with the intended uniform charging of the cost of building the REZ. Priority access on the other hand implies some form of ranking, and synthetic priority dispatch right to connecting VRE generators (i.e. presumably in the order of entry: last-in, first-out of the dispatch process) in the REZ, despite equal charging for access. These two regimes produce strikingly different outcomes given Australia's NEM Design. Of utmost importance to the analysis here are the points of intersection in Fig.6a and 6b.

- In an electricity market in which the inherent design observes ***average curtailment*** as the relevant metric (e.g. zonal market, non-firm open access), in equilibrium, our model produced a result 2,300MW of installed wind capacity with an average cost (given fleet-wide curtailment rates) and market prices of A$72.5/MWh, with zero average profits (consistent with free entry).

- Conversely, in a market design which observes ***marginal curtailment***, (e.g. zonal market with priority access, or a nodal market with allocated REZ financial transmission rights), in equilibrium the market may be expected to deliver 1,650MW of wind capacity at equivalent prices, but with economic rents given average cost reflects minimal curtailment.

Parallel results can be observed in Fig.6b for solar PV. That is, for ***average curtailment*** (e.g. zonal market, non-firm open access), in equilibrium, our model produced a result of A$65/MWh with investment in solar capacity trending towards 860MW. Conversely, with ***marginal curtailment*** (e.g. priority access), in equilibrium our model delivered ~540MW of solar PV capacity at broadly equivalent prices.

Above all are the implications for consumer welfare. The only basis upon which a zonal market with priority access might achieve 2,300MW of investment in wind capacity (i.e. the non-firm access result) would be to force producers up the Long Run Marginal Cost curve, with clearing prices rising from A$72.5 to A$96/MWh. And similarly, the only basis upon which priority access would deliver 860MW of solar PV capacity (i.e. the non-firm access result) would be if dispatch weighted prices for solar rose from A$65 to A$91/MWh. Combining the results from Fig.6 and Tables 5-6, the changes in welfare are therefore as follows:

- A decision to move from ***non-firm access*** to ***priority access*** would reduce consumer welfare for the ~1,500MW REZ by **A$169 million per annum –** a surprisingly large result for a single asset. These results are readily calculable through the data in Tables 5-6 and Fig.6.[9]

[9] The annual average change in wind and solar energy (Tab.5 Lines 2 and 22 *less* Tab.6 Lines 2 and 22, *divided by* 5 - being the number of years in Tab.5-6) multiplied by the difference in clearing prices at 2300MW of wind and 860MW of solar in Fig.6 at long run average and long run marginal costs.

- Equilibrium under ***non-firm open access*** was found to be 2,300MW of wind and 860MW of solar with annual production of 8,400GWh pa (see Tab.5) or 14% of Queensland demand. Conversely, equilibrium under ***priority access*** was found to be 1,650MW of wind and 540MW of solar with annual production of ~6,100GWh pa (see Table 6) or 10% of Queensland's aggregate final demand. Consequently, the productivity of the priority access REZ is materially (-27%) lower.
- The productivity of each REZ matters. Our model results exhibited higher output under a non-firm access regime. When this outcome is scaled across the power system, *more is achieved with less.* For example, reaching Queensland's 2032 target of 70% renewables could be achieved with **five fully subscribed REZs** under the existing non-firm access regime. Under priority access, **seven fully subscribed REZs** would be required to achieve the same result. That means two more REZs and two more episodes of navigating the complexity of encroaching on private land, risks of disturbing sites of cultural significance, competing with other environmental (i.e. biodiversity) objectives, and above all, enduring backlash from two more directly affected communities (see Simshauser, 2024), quite apart from being a theoretically inefficient solution (Newbery, 2024).
- Aggregate impacts on producer surplus are also material. There should be no question that investor 'equity rates of return' are maximised, and prima facie incumbent investor risks minimised, through *priority access*. But this comes with an important caveat. Renewable investors, as a class, are better-off under non-firm access because the available and tractable producer surplus (cf. priority access) expands by **A$107 million** per annum in net terms in each REZ, (i.e. A$172 million gross, albeit with the loss of A$65 million of *Economic Profits* in Table 6) at our preferred costs of equity and debt capital outlined in Table 2. Furthermore, while an investor may perceive priority access to be more desirable for near-term pending investments, most renewable developers have multiple sites across the NEM, and latter VRE development propositions face a naturally higher 'stranding risk' with priority access – as it discriminates in favour of early entrants over latter entrants.

7. Policy implications: non-firm vs priority access

Given the welfare implications arising from our model results, how do they translate to policy? Our results need to be interpreted very carefully. They apply to a specific market setup - Australia's NEM. The NEM comprises a multi-zonal, energy-only gross pool electricity market whereby the 5-minute dispatch algorithm includes a representation of the transmission network and consequently there is no 're-dispatch' required. Furthermore, generator access is non-firm – there are no side payments for spilled energy from VRE plant. This is inherent in the NEM's spot market design and in the market conventions underpinning the over-the-counter forward market for swaps, caps, Power Purchase Agreements (PPAs) and Contracts-for-Differences (CfDs). Finally, and crucially, all investors in Queensland REZ pay the pro-rata cost of the REZ and its access to the main transmission system, which logically (and theoretically) entitles them to pro-rata access rights (Newbery, 2024).

In short, in the NEM the full economic burden of paying for the REZ and experiencing the subsequent curtailment resides with renewable investors, who may continue to enter until excess profits fall to zero. Furthermore, even though the NEM presents as a zonal market, it comprises an acute higher-resolution locational signal or *spot price multiplier* through the ~1,400 site-specific Marginal Loss Factors (MLFs). A renewable generator with a CfD is paid as follows:

Spot Revenue = (*MWh exported* x *MLF*) x Spot Price (6)
Contract Revenue = (MWh exported x MLF) x (CfD Price – Spot Price) (7)
Total Revenue = Spot Revenue + Contract Revenue (8)

Again note there are no *side payments* for curtailment. Furthermore, it is a default market convention that forward instruments reference the zonal price at the relevant reference node.[10] This means the risk of subsequent changes to a renewable plant's site-specific MLF also resides with renewable investors.

Renewable investors therefore face two dimensions of locational signals and risk which tends to regulate entry. The first dimension is congestion / curtailment risk, and the second is the NEM's locational signal, the (multi-) zonal spot prices and site-specific MLFs ascribed to each bulk supply point.[11] As Eicke et el. (2020) explain, the combination of these latter two variables (i.e. zonal prices and MLFs) transmit amongst the strongest locational signals of the world's major electricity markets, including well known nodal markets such as PJM and ERCOT (Eicke, Khanna and Hirth, 2020).

Given the NEM market setup and market conventions, our model results and associated welfare implications are therefore clear cut. Prices may remain lower, quantities supplied higher, and consumer welfare maximised through maintaining non-firm access in which average curtailment rates are observed.

However, these same recommendations do not apply universally. For example, in Great Britain renewable generators enter with a form of synthetic *firm access* in a zonal market setup in which annual grid charges vary by zone. Renewable generators are paid for energy produced, and when curtailed for any reason, are also compensated for lost profits. The burden of curtailment risk is allocated to, and funded by, consumers. A similar setup exists in Germany, for example.

With a single zonal wholesale price, no Marginal Loss Factors and curtailment risks borne by consumers – unsurprisingly – there has been excess entry in the north of GB (and in the north of Germany) where wind resources exceed network transfer capacity to the south, where major load centres are located. In GB, entry has continued in the north (Scotland) in the presence of known and rising network congestion, and the cost of re-dispatch and curtailment-payments frequently run to as much as 10-30% of market volumes, with estimates of the 'balancing mechanism uplift' trending towards £4-6 billion per annum (Gowdy, 2022; Newbery, 2023a).

To put this situation into perspective by reference to Fig.6, market conditions in Great Britain (and Germany) are the equivalent of producers facing the expansion path of the Long Run Average Cost curve, while consumer prices follow the trajectory of the

[10] That is, Queensland, New South Wales, Victoria, South Australia or Tasmania.
[11] MLFs are adjusted each year to their expected (year-ahead) value and will fall with increasing current as capacity increased.

steep, upward sloping Long Run Marginal Cost curves. These market conventions have resulted in research into altering the contracting arrangements (Newbery, 2023a). The Australian case is of course the *exact opposite*.

8. Concluding Remarks

A decision to change access rights from non-firm to priority for new entrant projects in Australia's NEM would guide renewable curtailment to marginal rates. This would have the effect of underutilising a scarce resource (i.e. VRE transmission network hosting capacity), constraining entry across critical locations and raising prices. In economics, marginal costs and prices are generally thought to be more efficient than average but it is preferable to consider both the REZ cost and curtailment together where if the first is pro-rata then so should be the second. Under other access and charging regimes (e.g. on European markets with all transmission charges allocated to load so there are no locational signals for access) then priority access can counteract that inefficiency. Even then priority access assumes that the transmission system can be expanded endlessly to accommodate entry.

But this is not the environment that Australian policymakers are facing. Even in a vast geographic state like Queensland, there are constraints on rolling out additional (and arguably unnecessary) REZs. There are limits to development in every jurisdiction. The efficient market principle of setting price signals at marginal cost assumes that all other relevant services (e.g. transmission access) are efficiently priced. There are many applied examples where the underlying assumptions which drive the efficiency of the classic microeconomics result break down, at which point policymakers and regulators step in to guide markets to maximise welfare over the free market solution (economic regulation of monopoly electricity network utilities being a case in point).

To summarise results, non-firm access in our REZ led to 2,300MW of wind capacity in at A$72.5/MWh. A priority access regime requires a clearing price of A$97/MWh to achieve the same result. Maximising welfare therefore arises with the non-firm open access regime and a pro-rata REZ charging regime. In addition, non-firm access (average curtailment) has the advantage of extracting economic rent from early entrants, thereby reducing costs to consumers.

For VRE producers, the risk of curtailment is as it has always been – a forecastable risk. The extent of this risk in any given location will be regulated by equity investors and risk-averse project banks after accounting for expected (zonal) spot and forward prices, forecasts of Marginal Loss Factors, future entry until the last entrant makes zero surplus profit given the likely resulting network congestion of the current location and in the context of the broader market.

For new entrants, curtailment rates should rise in line with average curves. PPAs are time-limited and on maturity, resets will no doubt incorporate prevailing expectations of curtailment-adjusted new entrant costs. And as Gohdes et al., (2022, 2023) recently observed, equity Internal Rates of Return associated with renewable projects in the NEM present as efficient, stable and with investors increasingly taking on some element of merchant exposure – a risk-adjusting mechanism to accommodate the array of uncertainties facing all generation projects.

By comparison to priority access, it would seem the NEM's existing non-firm, open access regime maximises welfare with two important caveats.

1. policymakers may need to consider whether some form of time-limited, aggregate capacity restriction is placed over a REZ and/or nearby transmission assets to guide (i.e. limit) cumulative curtailment rates for the investor market to limit the risk of material over-investment in capacity; and
2. There may be some unintended residual risk in the NEM's dispatch algorithm in which a connecting generator 'just downstream' of a REZ may be inadvertently gifted with a favourable constraint coefficient, which in turn simulates some element of priority dispatch. One out-working of this article is that NEM policy advisors should work towards better risk sharing than worse, for example, by 'rounding' constraint coefficients and equations so as to avoid *false precision* in the real-time dispatch of zero marginal cost resources.

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Appendix I

Table A1 – Goncalves & Menezes (2021) NEM spot price coefficients

Hour	Wind			Solar		
	Min95	Est.	Max95	Min95	Est.	Max95
0	-0.00021	-0.00028	-0.00033	0.00350	-0.00067	-0.00095
1	-0.00020	-0.00030	-0.00033	0.00325	-0.00056	-0.00073
2	-0.00019	-0.00033	-0.00036	0.00555	-0.00051	-0.00076
3	-0.00024	-0.00035	-0.00039	0.00421	-0.00041	-0.00061
4	-0.00027	-0.00038	-0.00042	0.00252	-0.00041	-0.00057
5	-0.00028	-0.00038	-0.00044	0.00412	-0.00032	-0.00050
6	-0.00019	-0.00031	-0.00040	0.00534	-0.00015	-0.00070
7	-0.00015	-0.00039	-0.00049	0.00861	-0.00113	-0.00161
8	-0.00023	-0.00029	-0.00034	0.00507	-0.00104	-0.00130
9	-0.00015	-0.00022	-0.00032	0.00456	-0.00082	-0.00116
10	-0.00010	-0.00029	-0.00035	0.00673	-0.00093	-0.00129
11	-0.00009	-0.00033	-0.00040	0.00696	-0.00079	-0.00119
12	-0.00015	-0.00033	-0.00039	0.00903	-0.00086	-0.00119
13	-0.00009	-0.00032	-0.00038	0.00610	-0.00067	-0.00104
14	0.00004	-0.00022	-0.00031	0.00679	-0.00056	-0.00124
15	0.00029	-0.00005	-0.00019	0.01042	0.00013	-0.00105
16	0.00048	0.00003	-0.00018	0.01389	-0.00015	-0.00150
17	0.00066	-0.00001	-0.00026	0.01916	0.00049	-0.00101
18	0.00021	-0.00044	-0.00061	0.01114	0.00074	-0.00045
19	0.00030	-0.00038	-0.00053	0.00941	0.00040	-0.00094
20	0.00005	-0.00028	-0.00033	0.00527	-0.00060	-0.00094
21	-0.00008	-0.00024	-0.00028	0.00348	-0.00068	-0.00092
22	-0.00021	-0.00026	-0.00029	0.00480	-0.00074	-0.00092
23	-0.00017	-0.00024	-0.00028	0.00495	-0.00071	-0.00090

Table A2 – Spot Prices Average Curtailment Equilibrium (2300MW Wind, 860MW Solar PV)

	Spot Prices		2017	2018	2019	2020	2021	Total
1	Time Weighted Average	($/MWh)	102.1	74.5	71.5	40.9	87.4	75.3
2	Wind Dispatch Weighted	($/MWh)	96.7	76.0	74.8	43.9	91.4	76.3
3	Wind % of Average Spot	(%)	95%	102%	105%	107%	105%	101%
4	Solar Dispatch Weighted	($/MWh)	110.1	70.8	65.4	37.2	57.0	69.6
5	Solar % of Average Spot	(%)	108%	95%	92%	91%	65%	92%
6	95th Percentile Price	($/MWh)	47.5	46.3	28.6	4.3	-5.2	18.1
7	5th Percentile Price	($/MWh)	147.1	125.1	127.0	78.4	194.0	134.3
8	Negative Price Events	(Hrs)	13	114	4,413	453	4,799	9,792
9	Coefficient of Variation		2.9	0.5	0.6	1.2	4.2	2.8
10	Kutosis		634	358	531	308	637	1,568
11	Skewness		23	14	10	14	22	34
12	Mininum Spot Price	($/MWh)	-176	-144	-674	-546	-1,000	-1,000
13	Maximum Spot Price	($/MWh)	10,618	1,289	2,145	1,275	15,000	15,000