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Competition vs. coordination: Optimising wind, solar and batteries in renewable energy zones

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ABSTRACT

Decarbonising Australia's power system requires high market shares of variable renewable energy. An important policy initiative to achieve this is the establishment of Renewable Energy Zones (REZs). As renewable market share increases, curtailment within REZs is predictable. Curtailment occurs due to low utilisation rates or high peak-to-average output ratios of intermittent renewables (being ~3:1), largely inelastic aggregate final electricity demand, and the economic limits of REZ network transfer capacity. In an open access, multi-zonal market setup, an intuitive response by policymakers may be to undertake connection reform (i.e. priority access) and underwrite storage assets to alleviate the worst effects of curtailment. Prima facie, curtailment and lines congestion may be reduced and wind and solar capacity increased through the deployment of battery storage. However, as model results in this article reveal, priority access can make multi-zonal markets more sensitive to curtailment, and competitive batteries within a REZ can aggravate congestion. Further, early entrant batteries may oversize their MW capacity and crowd-out renewables. All these cases harm welfare within a REZ. Optimally sized and coordinated 'portfolio' batteries alleviate congestion because they don't compete for scarce REZ transfer capacity.

1. Introduction

Renewable Energy Zones or 'REZs' have become a key policy initiative of the State Governments that comprise Australia's National Electricity Market (NEM). Stylised on the Texas / ERCOT Competitive REZs, they are a means by which to create the necessary network hosting capacity needed to increase renewable market share and better coordinate decentralised generation investments (Doshi and Du, 2020; Jang, 2020). Two or three rival and sequentially located renewable investors, acting independently, may trigger multiple network augmentations to the transmission backbone. By contrast, a REZ entails a single set of connection assets traversing sequentially located projects.[1] REZs may therefore avoid needless network duplication, minimise community impacts, and by connecting multiple sequential renewable proponents, better utilise shared assets and lower total connection costs.

In the NEM's Queensland region, REZs are developed by the transmission utility under a semi-merchant model where user charges are levied on the connecting generators.[2] Development of renewable energy projects is notoriously difficult, and multiple projects reaching financial close simultaneously to underwrite an entire REZ could only happen by chance. Accordingly, and under the right conditions, the transmission utility will *'salami slice'* REZ user charges across anchor- and latter-entrant projects to minimise renewable plant entry costs (Simshauser, 2021). Under this approach, the transmission utility warehouses some level of (ex ante transient) idle REZ capacity to provide the necessary time for multiple projects to reach financial close. Understandably, both renewable developers and consumer groups support the model – with the latter especially supportive given the REZ transmission assets don't *'default'* into the consumer-funded Regulatory Asset Base.

In a deregulated market such as the NEM, renewable generators

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[1] The REZ envisaged in this article is a radial extending from the transmission backbone, and through an area containing high quality renewable energy resources. However as one reviewer noted, this can be simplified and generalised to an area of high potential renewable resources with a bottleneck in transmission network capacity.

[2] If REZ user charges are likely to exceed the capacity of connecting generators to pay, Qld has legislation which enables any residual asset value to be recovered through 'prescribed user charges' (i.e. to end-use consumers) subject to usual cost-benefit practices.

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operate in an intensely competitive environment. REZ assets and associated user charges must therefore be optimised to ensure minimum cost is achieved, and the economics of connecting generators are within existing market parameters. Sizing transmission investments is a straightforward process once potential renewable projects, quality of renewable investors, renewable resource complementarity, and the implications of renewable utilisation rates are understood.

This latter concept, 'renewable utilisation rates', are low by comparison to baseload plant, with solar typically spanning the range of 20–32 %, and wind from 30 to 45 %. But renewable utilisation rates also mean there will be high *peak-to-average output ratios* associated with the plant designed to replace baseload machines, and unlike peaking plant, output is not well correlated to aggregate final demand. This has very significant implications for power system planning, transmission utilisation and market design.

As Newbery explains in his numerous articles on the topic,[3] a 100 MW solar farm has a low utilisation rate of ~25 % but is also expected to reach its maximum output on a regular basis. It thus has a peak-to-average output ratio' of ~4:1 and for wind it is ~3:1. The NEM's renewable generators are therefore very different to the base load coal plants they are replacing. Low utilisation rates means that unconstrained network access for renewables is particularly inefficient. To generalise, minimum system cost necessitates that REZs be purposefully oversubscribed with wind and solar PV plant capacity – meaning some level of curtailment is inevitable, efficient and therefore desirable.

Well before optimal levels of Variable Renewable Energy (VRE) plant capacity enter a REZ, some level of congestion-driven curtailment arises. And as entry continues and the fleet-wide average rate of curtailment rises, the Annual Capacity Factor of renewable projects within the REZ begins to fall – ultimately reaching a tipping point of *"bankability*[4]". Critically, the marginal rate of curtailment arising from transmission line congestion will rise at 3–4 times the average rate of curtailment (Newbery and Biggar, 2024; Simshauser and Newbery, 2024). This means the final MW of wind capacity installed in a congested REZ may produce as little as 40 % of the first MW of wind capacity installed. The implication of these dynamics for (i) transmission access policy, and (ii) the role of storage, is material.

The purpose of this article is to identify the process for identifying the optimal mix of complementary VRE plant capacity in a REZ under two different access regimes, with and without short duration battery storage in a multi-zonal electricity market setup. While optimising complementary REZ plant capacity has previously been examined (see Simshauser et al., 2022; Simshauser, 2024b; Simshauser and Newbery, 2024) – prior research excluded the impact of battery storage. This article aims to fill that gap.

The focus on short duration battery storage (cf. emergent long duration storage technologies) reflects the fact that such investment commitments in Australia's NEM are surging (see Table 1). At the time of writing, almost 1800 MW of batteries across 30 sites were operational, with a further 26 projects at financial close or under construction, taking the total to more than 8000 MW (with a further 10,947 MW approved for development) in a 35GW system. In the Queensland region, 2000+ MW have reached irreversible commitment and interestingly, none have been underwritten by government-initiated CfDs – each battery entered by way of bilateral, on-market transactions.

Table 1
Battery storage projects (NEM and Queensland region).

NEM	Count	Capacity (MW)	Storage (MWh)	Duration (Hrs)
Operating	30	1767	2671	1.5
Construction	22	5233	12,663	2.4
Financial Close	4	1340	5910	4.4
Committed	56	8340	21,244	2.5
Approved	41	10,947	47,823	4.4
QLD				
Operating	8	437	818	1.9
Construction	7	1655	4510	2.7
Financial Close	0	–	–	–
Committed	15	2092	5328	2.5
Approved	21	7260	39,900	5.5

Source: Rystad Energy, Powerlink.

Underpinning NEM battery entry are market dynamics associated with a 'solar-rich' power system, combined with largely inelastic aggregate final electricity demand and inflexible baseload plant. Collectively these characteristics have produced some of the highest intra-day price spreads across the worlds' major electricity markets over the period 2021–2024 (i.e. negative price events for charging, and evening price spikes during post-solar periods for dispatch).[5]

Given the extraordinary level of investor interest in short duration battery storage, it is appropriate to explore the welfare implications of battery additions *within a REZ* under varying access arrangements (open vs. priority) and industrial organisation (coordination vs. competition). For this purpose, the REZ Optimisation Model from Simshauser and Newbery (2024) has been modified, thus drawing on renewable resources and market data from the NEM's Queensland region.

REZ Optimisation Model analyses of access arrangements and industrial organisation reveal striking results. To summarise these, Queensland wind and solar are complementary resources, and so a ~ 1500 MW transmission line will host vastly more installed wind and solar capacity than 1500 MW. The outer-bound of *"bankable"* complementary VRE capacity is invariably regulated by capital markets *tolerances* for curtailment. Second, in a multi-zonal market setup, open access (cf. priority access with financial access rights) proves welfare enhancing because of the low utilisation rates of VRE plant. And finally, and perhaps (prima facie) counterintuitively, competitive battery entrants or oversized early-entrant batteries *within a REZ* harm welfare in deregulated markets. This occurs in either an open access or a priority access regime. Rival batteries compete for scarce REZ network access and crowd-out VRE entry, thereby damaging productivity. Conversely, coordinated *portfolio batteries* within a REZ increase productivity and welfare.

This article is structured as follows. Section 2 provides a brief review of literature. Section 3 introduces the REZ Optimisation Model and associated data. Section 4 provides a short primer on access regimes and REZs. Section 5 presents model results. Policy implications and concluding remarks follow.

2. Review of literature

Progressively adding VRE capacity to a power system introduces different challenges as the market share of intermittent plant rises. In the early deployment phase (during the 2000s), scale and cost were the main problems to be solved. These were overcome by policy priming, viz. renewable portfolio standards and certificated schemes, centrally

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[3] (Newbery, 2021, 2023c, 2023b; Newbery and Biggar, 2024; Simshauser and Newbery, 2024)

[4] As one reviewer noted, for a project to be 'bankable' it must have adequate risk mitigation measures in place across a range of dimensions including the technology selected, expected construction costs, the adequacy (or degree of certainty) of expected future revenues and asset-related management and maintenance plans – ex ante. In this research, the focus is on the adequacy of expected future revenues with a special focus on forecastable curtailment effects – with all other variables (technology, capex costs, asset maintenance) assumed to be satisfactorily dealt with.

[5] Rystad Energy recently analysed 39 international electricity markets (2021–2024) and the NEM regions of Queensland, South Australia and New South Wales consistently exhibited (by far) the highest intraday spreads.

auctioned Contracts-for-Differences, and Feed-in Tariffs (Buckman and Diesendorf, 2010; Nelson et al., 2013; Schelly, 2014; Nelson, 2015; Nelson et al., 2022; Newbery, 2023b; Newbery, 2023a).

When VRE market share further increased to ~20 % (during the 2010s), merit order effects were revealed. Merit order effects were accompanied by rising episodes of negative prices (Sensfuß et al., 2008; Felder, 2011; Forrest and MacGill, 2013; McConnell et al., 2013; Cludius et al., 2014; Antweiler and Muesgens, 2021).

International dynamics arising from multilateral agreements (e.g. Paris Agreement), jurisdictional policy initiatives (e.g. Inflation Reduction Act) and global energy shocks (e.g. Russia-Ukraine War) led to rapidly surging investment in renewables (Nelson, 2020; Simshauser and Gilmore, 2022; Fabra, 2023; Pollitt, 2023a). In certain power systems, VRE plant capacity rising beyond ~30 % led to a third wave of challenges – those associated with system strength shortfalls (Badrzadeh et al., 2020; Hardt et al., 2021; Qays et al., 2023), deteriorating inertia (Newbery, 2021), falling minimum loads (Billimoria and Poudineh, 2019; Billimoria and Simshauser, 2023; Simshauser and Wild, 2025) and in some instances, disorderly thermal plant exit (Nelson, 2018; Nelson et al., 2018; Dodd and Nelson, 2019; Rai and Nelson, 2021; Flottmann, 2024).

Holding all else constant, rising levels of VRE will be accompanied by ever-increasing curtailment rates. As noted above, Professor Newbery explains why this is the case –*peak-to-average output ratios* of VRE (Newbery, 2021, 2023b; Newbery, 2023a; Newbery, 2023c; Newbery and Biggar, 2024). The synchronicity of a large wind fleet, and of solar PV, results in *curtailment*, which arises from two distinct sources:

(i) *production curtailment* due to network congestion, where localised aggregate VRE output exceeds the transfer limits of the transmission network (McDonald, 2023, 2024); and
(ii) *economic curtailment* due to market imbalances, which occurs when aggregate VRE output exceeds inelastic aggregate final electricity demand (Newbery, 2023b), signalled by negative spot price events (Rai and Nunn, 2020).

Within industry circles, it is broadly accepted that one of the key constraints to VRE development is the adequacy of network hosting capacity (Kim et al., 2023; Simshauser, 2024). Rising levels of production curtailment amongst renewable producers signals an increasingly constrained power system, at which point capital markets will begin to regulate new investment (Gohdes, 2023; Gohdes et al., 2023; Simshauser and Newbery, 2024). If the cause of curtailment is rising network congestion, it is not until additional network hosting capacity arrives that further VRE investment is possible. One of the earliest observations of this cycle occurred in the Texas // ERCOT market (see Jang, 2020; Gowdy, 2022; Du, 2023). Renewable investment cycles were visibly apparent either-side of 'anticipatory investments' in ERCOT's Competitive REZ (Du and Rubin, 2018). Conversely, battery storage may be capable of alleviating some level of *economic curtailment* (Billimoria and Simshauser, 2023).

REZs have become an important policy initiative in Australia's NEM (McDonald, 2024; Simshauser, 2024). By definition, REZs involve network augmentations adjacent to the existing transmission backbone to connect multiple VRE proponents that may otherwise act, and connect, independently (Simshauser, 2021; McDonald, 2023; Newbery and Biggar, 2024). In theory at least, REZ should have the effect of minimising the risk of duplicate network investments and falling network productivity (Simshauser et al., 2022; McDonald, 2024). However, such outcomes are contingent upon some level of risk taking by a benevolent network planner (Simshauser, 2021), exploiting the complementarity of renewable resources (McDonald, 2023) and ensuring the access regime maximises welfare (Simshauser and Newbery, 2024). Intuitively, adding storage to a REZ should enhance the productivity and efficiency of a REZ (Newbery, 2018, 2023c; Billimoria and Simshauser, 2023) by reducing the worst economic effects of curtailment. But as subsequent modelling in Section 4 reveals, the prevailing transmission access regime, and the timing and industrial form of battery entrants, is vitally important.

3. REZ data and models

The modelling suite that follows draws directly from Simshauser and Newbery (2024) and extends this prior research by including multiple equilibria and short duration battery storage.[6] Full details are set out below but to summarise, modelling commences with a Project Finance Model to derive commercial wind, solar and battery plant costs. A REZ Optimisation Model then identifies the optimal investment mix (planning timeframes) and dispatch (operational timeframes) of VRE and battery storage. Historic hourly weather, matched to hourly NEM spot price data over a five-year period 2017–2021, forms the backdrop. Spot prices are dynamically adjusted vis-a-vis merit order effects by drawing on the work of Gonçalves and Menezes (2022), resulting in a rich set of investment outcomes in equilibrium (thus necessitating simulation iterations).

3.1. *Entry costs of wind, solar PV and battery storage*

The 'PF Model' is a conventional multi-period project and corporate finance program capable of simulating multiple generation technologies under a range of organisational structures and structured financing options. The PF Model produces generalised post-tax, post-financing Levelized Cost of Electricity estimates where structured finance and taxation variables are co-optimised endogenously. Inputs appear in Tables 2–3 and are consistent with Gohdes et al. (2022, 2023).

Project financings are 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's NEM.

As the model logic is set out in considerable detail in Appendix I of Simshauser (2024), it is not reproduced here. Critical PF Model outputs used in subsequent REZ Optimisation Modelling are as follows:

- Entry Cost of Wind \$93/MWh (incl. REZ user charges, ACF = 35 %)
- Entry Cost of Solar PV \$68/MWh (incl. REZ user charges, ACF = 26.5 %)
- Entry Cost of Batteries[7] \$11.0/MW/h for the 1st hour storage and \$4.5/MW/h for each subsequent hour of storage.

Table 2
PF Model parameters (pre-connection costs).

Variable Renewable Energy		Wind	Solar	Battery
Nominal Capacity	(MW)	1000	500	200
Overnight Capital Cost	($/kW)	2800	1600	525
Storage Cost	($/kW)			380
Cycles per Day				1
Annual Capacity Factor	(%)	35.0 %	26.5 %	–
Curtailment Limit	(ppt)	5	8	–
Auxillary Load	(%)	1.0 %	1.0 %	1.0 %
Marginal Loss Factor	(MLF)	0.980	0.970	0.980
Fixed O&M	($/MW/a)	29,940	20,000	10,000
Variable O&M	($/MWh)	0	0	Eqs. (8)–(9)
Useful Life	(Yrs)	35	25	20
Ancillary Services Costs	(% Rev)	−1.0 %	−1.0 %	30.0 %

Source: Gohdes et al., 2022, Gohdes, 2023.

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[6] Long duration technologies are beyond the scope of this research, and may produce quite different results.

[7] These represent the "carrying cost" of the battery. To determining the annual fixed and sunk costs of a 200 MW, 400MWh battery is therefore as follows: (\$11 + \$4.5) x 200 × 8760 h = \$27.2 million pa.

Table 3
PF Model parameters (financial).

Renewable Project Finance		
Debt Sizing Constraints		
- DSCR	(times)	1.25
- Gearing Limit	(%)	82.5 %
- 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	(%)	4.12 %
- Term Loan B Spread	(bps)	180
- Term Loan A Swap	(%)	4.23 %
- Term Loan A Spread	(bps)	209
- Refinancing Rate	(%)	6.2 %
Expected Equity Returns	(%)	8.0 %

Source: Gohdes et al., 2022, Gohdes, 2023, Bloomberg.

3.2. Overview of REZ optimisation model setup

The REZ Optimisation Model setup is structured as a Stackelberg game along similar lines to Hassanzadeh Moghimi et al. (2024). A benevolent welfare maximising transmission utility forms the leader. Renewable developers are the followers. In the upper level, the transmission utility endogenously determines the REZ network capacity and user charges. In the lower-level, Nash-Cournot games amongst profit-maximising renewable developers occur over two timeframes. First, *competition for the market* occurs in planning timeframes (i.e. plant investment commitments). Second, *competition in the market* occurs in operational timeframes (i.e. dynamic dispatch, hourly resolution, five-year period). Investment commitment and subsequent dispatch of the VRE and storage fleet is assessed under two transmission access regimes in a multi-zonal market setup:

1. Non-firm ‘open access’ (the NEM’s current format); and
2. ‘priority access’ (involving REZ access rights).

As subsequent modelling reveals, the welfare implications of these opposing access regimes are material (see also Simshauser and Newbery, 2024). In all scenarios, REZ transmission infrastructure is assumed to be *merchant,* meaning committed entrants are liable for REZ user charges. The transmission planner seeks to optimise plant connections for a given access regime, bounded by REZ network capacity limits, *tolerable* VRE curtailment rates, and the requirement to ultimately recover its infrastructure costs and returns on committed capital. Tolerable curtailment rates for wind and solar plant means they must be *“bankable”* – the levels of which are set by project banks and equity investors (Gohdes, 2023; Gohdes et al., 2023). *Bankable* curtailment rates are set exogenously in, and managed within, the REZ Optimisation Model with ’$wind \ngtr 5\%$ *lost production*’ and ’*solar PV*$\ngtr$8% *lost production*’.

VRE plant are exposed to negative price events, which drives *economic curtailment.* As noted earlier, this is a separate category of production losses and is inherently uncertain, ex ante. To illustrate the cumulative effect of curtailment, using wind with an ex-ante 35 % Annual Capacity Factor as a simple example, is as follows:

$$\textbf{Potential Wind Output} = 35.0\ \%\ \text{ACF}$$
$$\textit{Less curtailment from congestion}(\ngtr 5\%\textit{production losses or } 1.8\%\textit{ACF}.)$$
$$\textbf{Practical Wind Output} = 33.2\ \%\ \text{ACF}$$
$$\textit{Less economic curtailment, negative prices } (e.g.0.2\%\textit{lost production})$$
$$\textbf{Economic Wind Output} = 33.0\ \%\ \text{ACF}$$

Scenarios will examine, and isolate, impacts of battery storage under distinctly different industrial organisation involving ‘rival entrants’, and (non-rivalrous) ‘co-ordinated portfolio entrants’.

3.3. Wind and solar data

The specific area (and weather data) being modelled is the Western Downs REZ in the NEM’s Queensland region (Fig. 1). The diurnal pattern of VRE on Queensland’s Western Downs exhibits a level of complementarity, with average wind output rising either side of solar PV output (see Fig. 2). Seasonal average correlation of wind and solar ranges from −0.75 in spring to −0.69 in winter. It is this complementarity which helps explain the intuition behind subsequent quantitative results, viz. a priori expectation that combined VRE plant capacity will exceed REZ transmission line transfer limits. However, hourly weather data exhibits much greater variability than seasonal averages (with the correlation reducing to −0.28) meaning high-resolution modelling is required to identify the true extent of portfolio diversity, and consequential impacts of energy storage.

The REZ Optimisation Model seeks to identify the optimal mix of VRE plant capacity given Western Downs renewable resource options, specified network transfer capacity, and five years of historic hourly weather reanalysis from 2017 to 2021 (drawn from Gilmore et al., 2022). A statistical summary of the appropriately matched spot price data over the same period appears in Table 4, including the time-weighted average (Line 1) and selected statistics (Lines 2–13).

Optimisations introduce differing levels of wind and solar plant capacity, which implies variations arising from merit order effects. Consequently, use of historic spot prices needs to be adjusted. As Bushnell and Novan (2021) and Gonçalves and Menezes (2022) show in the case of California and Australia respectively, variations in wind and solar PV plant capacity impact hourly prices differentially – both downwards (renewables on) and upwards (renewables off). Accordingly, and consistent with the modelling approach in Simshauser and Newbery (2024), the REZ Optimisation Model internalises the hourly wind and solar PV regression coefficients from Gonçalves and Menezes (2022), which in turn allows the model to dynamically adjust prevailing spot prices as VRE capacity levels are varied, noting that, for example, more solar has a price impressing effect during daylight hours, and an inverse effect during non-solar hours. The coefficients appear in Appendix I.

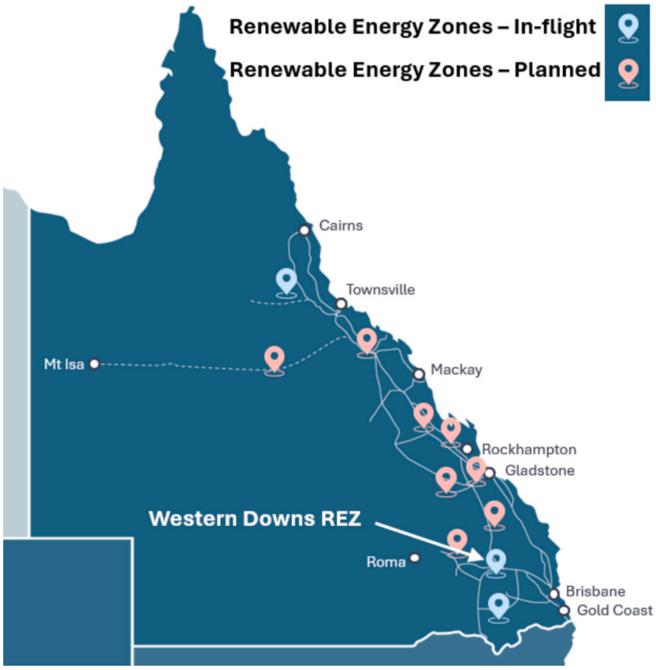

Figure 1. Renewable energy zones in Queensland.

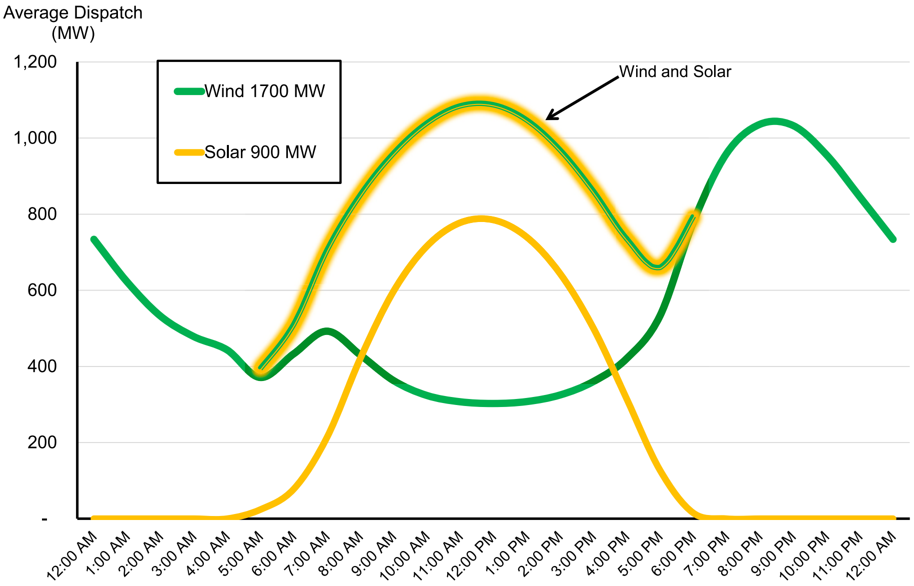

Figure 2. Average summer wind and solar PV output (Western Downs).

Table 4
Statistical summary of spot prices and dispatch-weighted prices (2023$).

	Spot Prices		2017	2018	2019	2020	2021	Total
1	Time Weighted Average	($/MWh)	126.8	90.9	85.9	48.5	104.2	91.2
2	Wind Dispatch Weighted	($/MWh)	119.7	91.1	88.8	51.8	107.1	91.7
3	Wind % of Avg Spot	(%)	94 %	100 %	103 %	107 %	103 %	101 %
4	Solar Dispatch Weighted	($/MWh)	136.0	85.5	78.0	44.5	67.9	84.1
5	Solar % of Avg Spot	(%)	107 %	94 %	91 %	92 %	65 %	92 %
6	90th Percentile Price	($/MWh)	69.7	62.1	48.8	20.4	21.1	35.0
7	Standard Deviation	($/MWh)	360.4	47.3	54.2	58.7	435.3	257.4
8	Negative Price Events	(Hrs)	13	14	129	333	507	996
9	Coefficient of Variation		2.8	0.5	0.6	1.2	4.2	2.8
10	Kurtosis	($/MWh)	634.2	358.5	532.1	308.7	636.1	1543.5
11	Skewness	($/MWh)	23.2	13.6	9.8	14.2	22.0	34.3
12	Mininum Spot Price	($/MWh)	−217	−174	−805	−641	−1000	−1000
13	Maximum Spot Price	($/MWh)	13,145	1566	2563	1499	16,600	16,600

Source: Australian Energy Market Operator.

3.4. Structure of the REZ optimisation model

REZ Optimisation comprises a structural LP Model, commencing with a double circuit 275 kV radial connection on Queensland's Western Downs linking back to the transmission backbone (Fig. 1). The radial REZ network comprises multiple generator connection points. REZ transfer limits are driven by conductor type, allowable operating temperatures with normal seasonal line ratings (~200 km from Australia's coastline). Seasonal transfer limits, capital cost and annual users charges are set out in Table 5.

The REZ Optimisation Model seeks to maximise either aggregate output or profit, subject to a series of nominated constraints as set out below. The model is grounded firmly in welfare economics with optimisations measuring changes to consumer and producer surplus:

Table 5
Double circuit 275 kV REZ, seasonal transfer limits and costs.

	Normal Rating (MW)
Summer	1536
Autumn/Spring	1756
Winter	1916
REZ Capital Costs	$450 million
REZ User Charges	$45 million pa

Let $g \in G$ be the set of potential renewable generators (i.e. wind and solar PV), each with installed capacity K_g, connecting to the REZ which has seasonal line ratings REZ^s. Let $C_{g,t}$ be the perfectly divisible unit cost of each renewable generation technology at any scale ($/MWh) as derived by the PF Model. Let $t \in T$ be the set of hourly dispatch intervals with plant availability in period t being $\beta_{g,t}$. Let $q_{g,t}$ be the output of generator g in trading interval t with the relevant spot price received for output being $p_{g,t}$. At this point, the objective function for maximising welfare becomes a relatively straight-forward one:

$$OBJ_W = Max\left(\sum_{t \in T}\sum_{g \in G} q_{g,t}\right), \tag{1}$$

S.T.

$$\sum_{g \in G} q_{g,t} \leq K_g \bullet \beta_{g,t} \forall g \in G, t \in T, \tag{2}$$

$$\sum_{g \in G} q_{g,t} \leq REZ_t^s \forall t \in T, \tag{3}$$

$$\left(\sum_{t \in T}\sum_{g \in G} q_{g,t}\right) \geq \left[\sum_{t \in T}\sum_{g \in G}(1-\delta_g) \bullet e\left(q_{g,t}\right)\right], \tag{4}$$

$$\left(\sum_{t\in T}\sum_{g\in G}q_{g,t}\bullet p_{g,t}\right)-\left(\sum_{t\in T}\sum_{g\in G}K_g\bullet C_{g,t}\right)\geq 0. \tag{5}$$

Eq. (1) sets the Objective Function for maximising Production. VRE resources are assumed to bid their output into the market at their marginal running cost (i.e. $0/MWh with tied bids allocating line capacity on a volume weighted basis). Eq. (2) limits generation dispatch to available capacity $K_g \bullet \beta_{g,t}$. Eq. (3) constrains total generation in each dispatch interval $t \in T$ to the seasonal transmission line flow limits of the Renewable Energy Zone REZ_t^s in accordance Table 3. Eq. (4) ensures wind and solar curtailment (δ_g) impacting expected output $e\left(q_{g,t}\right)$ of the optimised VRE fleet does not exceed exogenously determined *bankability limits* associated with contemporary project financings. And Eq. (5) ensures all production maximising solutions achieve a normal return, with revenue derived by production output $q_{g,t}$ at the relevant spot price $p_{g,t}$ with a level of normal profit being determined when entry costs of plant, $C_{g,t}$, equal revenues. Any level above this represents supernormal profits, since entry costs arising from the PF Model include normal returns to equity. The objective function for profit maximising scenarios (OBJ_{EP}) is similarly straight forward:

$$OBJ_{EP}=Max\left[\left(\sum_{t\in T}\sum_{g\in G}q_{g,t}\bullet p_{g,t}\right)-\left(\sum_{t\in T}\sum_{g\in G}K_g\bullet C_{g,t}\right)\right], \tag{6}$$

S.T. Eqs. (2)–(4).

In specific scenarios, short duration battery storage h is made available to form part of the potential fleet of REZ-connected generators $h,g \in G$. Batteries may be *'competitive rivals'* within the REZ, or may form part of a *'coordinated portfolio'* of VRE assets.[8] Regardless of whether the model seeks to maximise production Eq. (1) or profit Eq. (6), *rival batteries* always seek to maximise arbitrage profit each day (Arb_d) for any given level of storage, *n*. Batteries achieve this by discharging $\left(q_{h,t}\right)$ during the maximum daily spot price events $(pmax_t)$, and recharging $\left(-q_{h,t}\right)$ during minimum daily spot price events $(pmin_t)$, such that $q_{h,t}\in[-K_h,+K_h]$. Batteries are strictly limited to one cycle per day with the optimisation ensuring the diurnal storage balance $\left(\sum_{t=1}^{n}q_{h,t}=0\right)$ is met. How this is formally implemented in the model is with perfect foresight of spot prices (24 h ahead), with daily bids and offers changing dynamically to meet the objective function[9]:

$$Arb_{h,d}=\left(\left(\sum_{t=1}^{n}pmax_{h,t}\bullet q_{h,t}\right)+\left(\sum_{t=1}^{n}pmin_{h,t}\bullet -q_{h,t}\right)\right) \tag{7}$$

Charging and dispatch of coordinated portfolio batteries is subtly different. In any trading interval where aggregate VRE output $q_{g,t}$ is expected to exceed REZ_t^s seasonal transmission line ratings, the prevailing spot price $\left(p_{h,t}\right)$ is deemed to be zero for the battery $\left(\widehat{p}_{h,t}=0\right)$ such that:

$$Arb_{h,d}=\left(\left(\sum_{t=1}^{n}\widehat{p}max_{h,t}\bullet q_{h,t}\right)+\left(\sum_{t=1}^{n}\widehat{p}min_{h,t}\bullet -q_{h,t}\right)\middle|if\left\{\begin{array}{l}\sum_{g=1}^{G}q_{g,t}\geq REZ_t^s,\widehat{p}_{h,t}=0\\ \sum_{g=1}^{G}q_{g,t}<REZ_t^s,\widehat{p}_{h,t}=p_{h,t}\end{array}\right.\right). \tag{8}$$

The point of distinction between Eq. (7) and Eq. (8) is:

- *rival batteries* via Eq. (7) maximise profit given prevailing spot prices p_t;
- *portfolio batteries* via Eq. (8) treat transmission line congestion events as an opportunity to recharge at a 'deemed' zero price[10] and avoid further aggravating congestion and adjust output to work around wind and solar PV dispatch.

4. Primer on transmission access and REZs

Before proceeding to model results and the impact of batteries inside a REZ, it is worth examining the fundamentals of curtailment and transmission access, as these variables drive variations in the optimal plant mix.

4.1. On the theory of average vs marginal rates of curtailment

A distinguishing feature of any renewables-intensive grid is the inevitability of wind and solar curtailment. Curtailment in any dispatch interval may occur either because of transmission congestion, or because aggregate renewable supply exceeds aggregate final demand including storages.

Understanding the distinction between the *average rate of curtailment* and the *marginal rate of curtailment* is critical to understanding the subsequent analysis and the associated policy implications as they relate to Australia's NEM. This difference was examined in considerable detail in Simshauser and Newbery (2024) and so is not reproduced here. (For those not familiar with the distinction between average and marginal rates of curtailment, Appendix II provides a concise overview and illustration involving REZ Optimisation Model simulations). To summarise, given the NEM's multi-zonal market setup and open access regime, new plant commitments within a REZ are exposed to *average rates of curtailment*. If access in the NEM was changed to 'priority access' as has been proposed from time to time, new entrant plant would face the *marginal rate of curtailment*, as occurs in nodal markets as financial transmission rights are allocated.

4.2. On 'open access' vs 'priority access' in a zonal market

In a multi-zonal market setup like Australia's NEM, different access arrangements induce different rates of curtailment for renewable plant. Model simulations in Section 4.3 will illustrate this by contrasting optimal outcomes for the existing open access regime with priority access. And, simulating a priority access regime within the NEM's multi-zonal market broadly parallels locational marginal pricing with financial transmission rights. Specifically:

1. **Open Access:** Simulating the NEM's existing 'open access' regime in the REZ Optimisation Model formally occurs through Eq.(1) in which renewable plant face the average rate of curtailment along with all

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[8] As one reviewer noted, longer duration and seasonal storage would present different possibilities for a REZ.

[9] It is to be noted that in a zonal market setup when congestion occurs and inframarginal rents are available given prevailing spot prices, generators behind a constraint may each bid below their marginal cost in order to create tied-bids, in which case their output will be dispatched on a volume-weighted basis. This is a known distortion in zonal market setups, and primarily impacts producer welfare and may adversely impact resource costs.

[10] While deeming the spot price at zero during congestion events, it does not discount the possibility of choosing to recharge at negative prices instead in order to maximise profit.

entrants in the REZ, as is the case in zonal markets. The objective function therefore maximises production subject to the technical, bankability and profitability constraints (Eqs. (2)–(5)). Here, new VRE plant enter continuously until economic rents are competed away, or to the bounds of tolerable curtailment rates (Table 2, Line 5). To be clear, in an open access regime, the burden of curtailment is shared amongst REZ entrants on a volume-weighted basis. And as is convention in the NEM's forward markets, there are no side-payments to compensate renewable plant for curtailment - the risk lies with investors.

2. **Priority Access:** Simulating priority access in the REZ Optimisation Model formally occurs through Eq. (6) in which renewable plant face the marginal rate of curtailment, as occurs in nodal markets as financial transmission rights are allocated. The objective function is to maximise profit subject to the same technical, bankability and profit constraints. The intuition behind Eq. (6) is priority access establishes a strict entry order. Once marginal economic profits fall to zero, which occurs as transmission line transfer capacity has been fully subscribed (and financial transmission rights are notionally fully allocated), entry will have reached its *'bankability nadir'* – at which point investment ceases. That is, curtailment is strictly ranked according to entry order.

Prior to exploring the simulation results as they relate to Australia's NEM, it is worth noting the differences between zonal markets and markets with locational marginal pricing. And, within zonal markets it is also worth noting the spectrum of designs that exist – some are significantly closer to nodal markets than others. With respect to nodal markets:

- First, it is to be noted that locational marginal pricing has long been acknowledged as the gold standard in market design for large thermal power systems. As Pollitt (2023b) explains, more location-specific prices can be taken to be more efficient than less.

- Second, while zonal markets aggregate a series of nodes to maximise forward market liquidity (cf. intra-regional basis risk), the design frequently carries an inherent inefficiency with dispatch. An expansive literature quantifies static dispatch inefficiencies that span the range 0.5–2.8 % (Green, 2007; Leuthold et al., 2008; van der Weijde and Hobbs, 2011; Oggioni and Smeers, 2012; Neuhoff et al., 2013; Oggioni et al., 2014; Abrell and Kunz, 2015; Aravena and Papavasiliou, 2017; Holmberg and Tangeras, 2023).
- Third, locational marginal prices are thought to better coordinate investment location decision-making.[11] Conversely, in certain zonal markets (e.g. Germany, Great Britain), the absence of locational prices has induced continuous suboptimal locational renewable investment decisions which further raises costs above the efficient level. Engelhorn and Müsgens (2021) find the cost of wind in Germany is 20 % higher due to the market's zonal design. In Great Britain, Gowdy (2022) and Newbery (2023a) identify spot market re-dispatch of 10–30 % of market volumes, once again owing to poor locational investment commitments.

- Indeed, locational signals in the German and British markets have historically been negligible. And the absence of locational signals had been amplified through the design of renewable PPAs and Contracts-for-Differences – with the main problem being side-payments or compensation for curtailment. That is, renewable plant were either priority dispatched, or guaranteed payments if curtailed, amplifying consumer costs and further muting locational signals. And repeated investments caused ever rising curtailment payments, from consumers to poorly located VRE generators.

Zonal market outcomes in Germany and Great Britain evidently do not accord with efficient results. However, while pronounced differences exist between US nodal and European zonal market designs, there are also pronounced differences amongst zonal markets. Australia's NEM sits somewhere between the US nodal and European zonal market spectrum. While a zonal market, the NEM has important locational features within its design that distinguish it from European models, specifically:

- First, Australia's NEM is a multi-zonal market, and zones reflect the historic build-up of regional transmission systems.

- Second, Australia's NEM applies Marginal Loss Factors (MLF) to each of the 1400 bulk supply points or nodes, based on forecast *marginal transmission losses,* ex ante with annual revision. And as Eicke et al. (2020) note, despite of its zonal design, the combination of the multi-regional prices and nodal MLFs means locational signals in Australia's NEM are amongst the strongest of 12 of the worlds' major electricity markets – with locational differentials equivalent to those observed in nodal markets such as PJM, ERCOT and CAISO (Simshauser, 2024).

- Third, security-constrained dispatch in Australia's NEM is in fact undertaken on a real-time nodal basis, and locational marginal prices are available within the dispatch engine – but in a practical sense the market design is multi-zonal (which has the effect of providing generators with a non-firm volume-based financial transmission hedge to the central nodal price). While this may seem a granular distinction, it explains why there is no 're-dispatch' in Australia's five-minute real-time spot market, viz. economic dispatch aligns with physical engineering constraints.

- Fourth, noting the NEM's representation of nodal constraints, generator bids cleared by the Market Operator in real time are adjusted by locational MLFs, meaning the five zonal prices reflect loss-adjusted, least cost bids whilst faithfully representing the transmission network. Zonal market dispatch inefficiencies still exist, but are estimated to be at the lower end of the stated 0.5–2.8 % range (i.e. ~0.8–1.0 %[12]). And unlike European zonal designs, inefficiencies associated with NEM dispatch are generally borne by plant investors (i.e. through resource cost misallocation) rather than elevated consumer prices because there is no re-dispatch.

- Finally, and above all, market convention for all PPAs in Australia's NEM excludes side-payments or compensation for curtailed output.[13] Consequently, poor investment location decisions by wind and solar PV investors will result in very severe financial losses, first through declining MLFs, compounded by curtailment without compensation.

4.3. REZ: Open access vs priority access in Australia's NEM

Recall from Section 4.1 that open access reflects the NEM's current design, and priority access is the equivalent of a nodal price setup with

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[11] This is thought to be the case for generation but is less clear for transmission. Congestion rents are known to fall within the range of 10–30 % of augmentation costs, and as (Eicke et al., 2020) and Joskow (2022) observe nodal pricing *has not* been responsible for large transmission augmentations in US markets.

[12] Modelling work undertaken by Roam Consulting in 2015 and NERA in 2020 on behalf of the Australian Energy Market Commission for 'CoGaTI' and predecessor projects.

[13] On-market over-the-counter transactions may deviate from this from time to time with the agreement of both counterparties.

financial transmission rights allocated. To see how these two transmission access regimes interact in Australia's NEM with a renewables fleet, the REZ Optimisation Modelling commences without storage. Recall also from Section 3 the structure of the REZ Optimisation Model involves iterating scenarios (50 iterations per scenario) because multiple credible equilibria exist for any given objective function. This is due to the rich variation in renewable resources and associated merit order effects. Simulation iteration results for the two access regimes are depicted by scatterplots in Figs. 3–4.

Fig. 3 highlights the wide array of viable wind (y-axis) and solar PV (x-axis) portfolio combinations in the open access regime – with the dominant portfolio (larger dot) comprising ~2050 MW of wind and ~ 1400 MW of solar, with aggregate output of 8700 GWh/a. For priority access, the dominant portfolio comprises ~1750 MW of wind and ~ 950 MW of solar, with annual output of 7100 GWh. To be clear, while a dominant portfolio has been identified, all reported 'dots' from each simulation iteration present credible investment outcomes, with energy output being ±2 % of the median.

Fig. 4 draws on the same dataset but presents the results in a slightly different way by measuring output on the y-axis, and the combined wind and solar PV capacity on the x-axis. Note the tight range of modelled annual output (y-axis result) against combined wind and solar PV plant capacity for each of the 50 iterations in each access regime. Above all, open access results in consistently higher VRE investment, and output, while meeting all REZ Optimisation Model constraints.

Table 6 presents the welfare analysis arising from the two scenarios. It can be observed that consumers prefer the REZ open access regime (8700GWh/a) as it results in 23 % more output than the REZ priority access regime for the same level of transmission infrastructure. Note specifically in Table 6 that consumer welfare improves by $71 m through open access (Line 1).

In Table 6, changes in producer surplus arising from access policy depend on entry timing. Early entrants prefer priority access ($61 m, Line 5). Indeed, in all priority access scenarios that follow, supernormal profits are a feature. The NEMs open access regime sees these supernormal profits competed away by latter entrants. Specifically, open access allows latter entrants to proceed to market and remain inside *bankable curtailment rates* because the burden of curtailment is shared across all entrants, including early entrants. Latter entrants would otherwise be *stranded* under priority access. Consequently, while early entrants lose economic profits, open access expands producer surplus by +$133 m, split between wind (+58 m, Line 2) and solar (+$75 m, Line 3). The net gain to producers amounts to +$72 m (Line 6) and the total change in welfare amounts to $143 m. Full model results underpinning Table 6 appear in Appendix II.

Prima facie, Figs. 3–4 and Table 6 present an unexpected set of results because it implies that the NEM's open access zonal market, rather than locational marginal prices, maximises welfare with respect to REZs. However, there are a critical list of caveats that comes with interpreting this result:

1. First, it is to be noted the same 'end state' achieved in Figs. 3–4 and Table 6 can also be replicated in a nodal market through the allocation of non-firm or 'shared curtailment' financial transmission rights – meaning either market design is capable of producing the same welfare maximising result.
2. Second, and above all, the implicit assumptions underpinning all results in this research is that (1) transmission is assumed to be costly, and (2) the ongoing development of transmission is assumed to be constrained due to the limits of community acceptance – and therefore minimising the transmission footprint is important. Maximum network utilisation of a radial REZ infrastructure, to the envelope of renewable plant bankability, therefore represents optimality.
3. The very low utilisation factors of renewable plant and their stochastic production output – output which not correlated to aggregate final demand - means sharing the burden of curtailment is more efficient than ranking curtailment to maximise output and REZ utilisation (noting point 2 above). This is a critical distinction from a large thermal power system, where plant output *is correlated* with demand, and sharing of curtailment (especially amongst base plant) may be inherently inefficient and may therefore harm welfare.
4. The conditions of the NEM's multi-zonal market design have been incorporated, including a representation of nodal constraints, locational MLFs, and crucially, the Australia's prevailing PPA market convention – no side-payments for curtailed energy.
5. In the model, capital markets are assumed to be rational, can accurately forecast curtailment risk, and therefore self-regulate entry to the limits of bankability.

Each of these caveats (2–5 in particular) are critically important to the modelled outcomes, and any deviation from may reverse welfare results in favour of locational marginal pricing. This leads us to an examination of storage within a NEM Renewable Energy Zone – where the inefficiencies of a zonal market setup are more likely to arise.

5. Adding merchant batteries inside renewable energy zones

The objective of this research is to identify the optimal mix of wind and solar resources under two states of storage, (1) a competitive 'rival' battery vs. (2) a coordinated 'portfolio' battery. Prima facie, we should anticipate significant differences between a rival battery and a portfolio battery:

- A stand-alone 'rival' battery will compete for transmission line access during its discharging cycle (see Eq. (7)); whereas
- A portfolio battery is assumed to be horizontally integrated with existing wind and solar within the REZ, and as outlined in Eq. (8), adjusts its operating regime around wind and solar output.

This leads to the eight simulations outlined in Table 7:

The eight simulations collapse down to four scenarios (1 & 2, 3 & 4 etc) which contrast Open Access vs. Priority Access. The first scenario (simulations 1 & 2) identify the impact of a portfolio battery while the second (simulations 3 & 4) identify the impact of a rival battery. The third scenario (simulations 5 & 6) examines the impacts of a large, short duration early entrant battery on total REZ productivity, while the final set of simulations (7 & 8) assess a large, longer duration early entrant battery. Each scenario produces subtly different insights for policymaking.

Why is access regime, battery size and entry timing important? Ultimately, REZ network transfer capacity is a scarce resource. Rising curtailment within a REZ harms VRE producer profits. It places hard limits on bankable renewable plant entry, at ~2050 MW of wind, and ~ 1400 MW of solar PV, as Figs. 3–4 noted.

Prima facie, it seems logical that adding battery storage within a *fully subscribed* REZ would improve VRE investor prospects. When a battery charges during REZ network congestion events (i.e. creating local demand), it may enable more wind and solar PV plant capacity to enter profitably since curtailment rates in the post-battery environment will have reduced back below the *'bankability threshold'*. However, as modelling results subsequently reveal, and regardless of whether the market is zonal or nodal, outcomes hinge critically on industrial organisation and entry timing – and whether batteries relieve or amplify congestion.

In the following simulations, the REZ Optimisation Model was allowed to choose any combination of wind, solar and battery storage that would maximise the objective function for open access Eq. (1) and priority access Eq. (6). When entering as a *competitive rival*, the battery strictly follows Eq. (7) – viz. seeking to maximise arbitrage revenues given prevailing spot prices. By contrast, *coordinated portfolio battery* entrants follow Eq. (8). This allows the battery to re-charge given

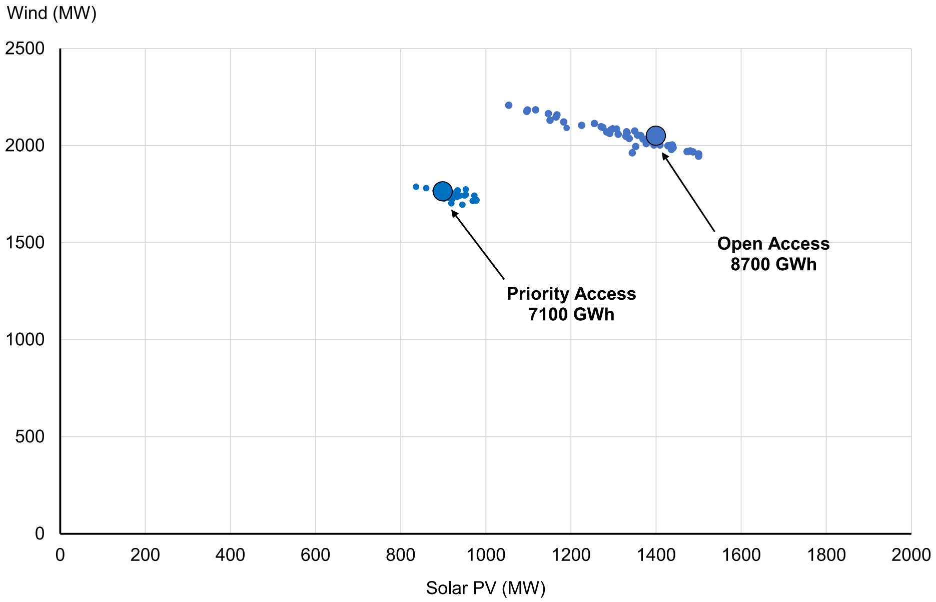

Figure 3. Optimal wind and solar capacity: Open access vs priority access.

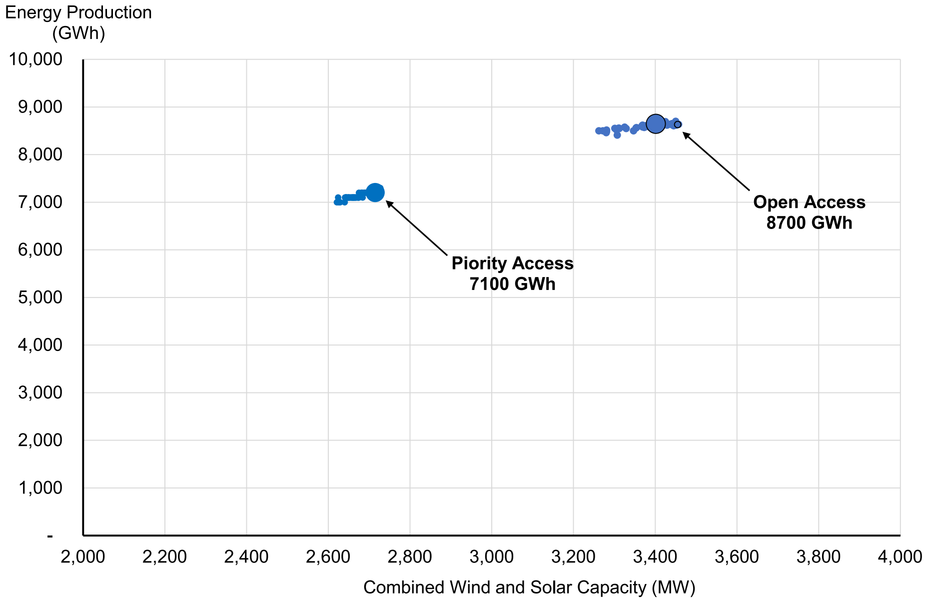

Figure 4. Optimal wind and solar production: Open access vs priority access.

Table 6
Welfare implications - open access vs priority access.

–		(Open - Priority Access) ($ Million pa)
1	Chg in Consumer Surplus	$71
2	Chg in Producer Surplus (Wind)	$58
3	Chg in Producer Surplus (Solar)	$75
4	Gross Chg in Producer Surplus	$133
5	*Lost Economic Profits* (Priority Access)	($61)
6	Net Chg in Producer Surplus	$72
7	Net Chg in Total Welfare	$143

Table 7
Simulation scenarios.

Scenario	Battery	Battery Industrial Form	Access Regime
1 VRE + Battery	Co-optimised	Portfolio Battery	Open Access
2 VRE + Battery	Co-optimised	Portfolio Battery	Priority Access
3 VRE + Battery	Competitor	Rival Entrant	Open Access
4 VRE + Battery	Competitor	Rival Entrant	Priority Access
5 VRE + Battery	Early Entrant	Portfolio Battery	Open Access
6 VRE + Battery	Early Entrant	Rival Entrant	Priority Access
7 VRE + Battery	Government CfD	Rival Entrant	Open Access
8 VRE + Battery	Government CfD	Rival Entrant	Priority Access

prevailing spot prices, or during localised REZ congestion events within the REZ if this is more profitable. Dispatch of coordinated batteries also avoids producing during congestion events.

Battery results are presented in Figs. 5–6. Fig. 5 presents four sets of results, commencing with the ‘no battery’ scatterplots (reproduced from Fig. 3, light grey dots), and then layers-in the 2 × 50 iterations from the REZ Optimisation Model for battery storage for each access regime (dark

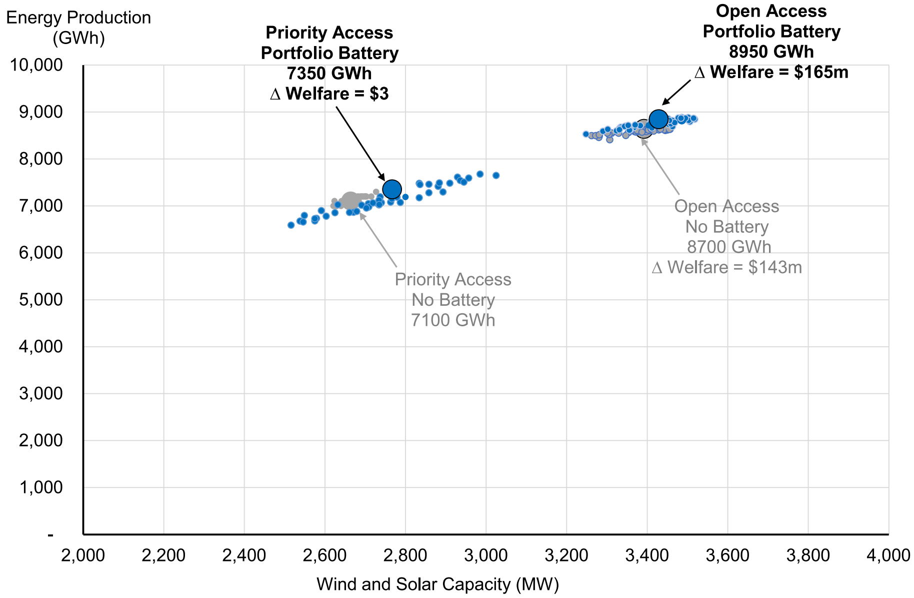

Figure 5. Impact of portfolio batteries.

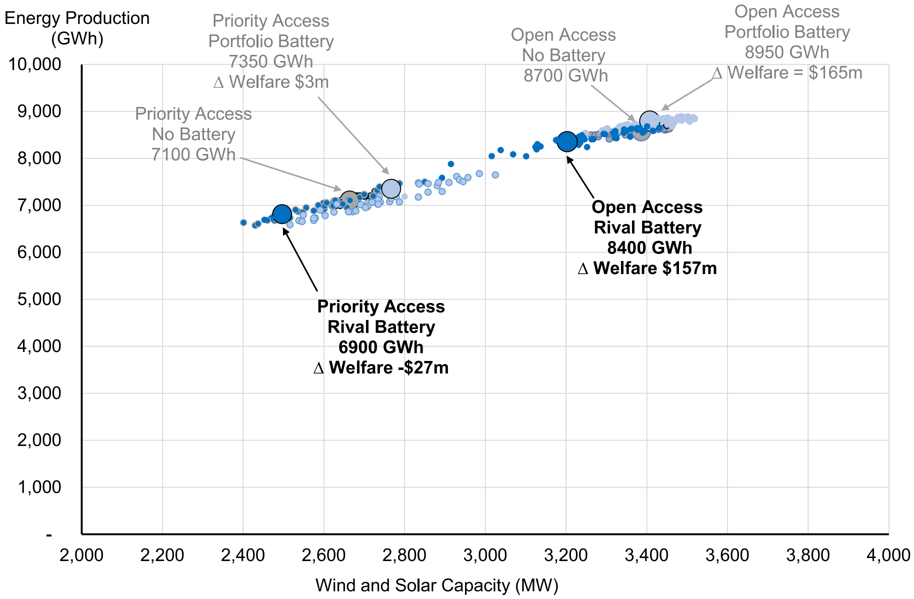

Figure 6. Impact of batteries by access regime and industrial form.

blue dots). Note under both access regimes, battery storage boosts annual output modestly (~250 GWh) and increases welfare by $3 m in priority access, and $22 m in open access in comparison to the 'Priority Access – No Battery' scenario (note that the 'Priority Access – No Battery' scenario forms the base case for the purposes of all welfare analyses in Figs. 3–6 and Figs. 9–10). How this is achieved is subtly different by access regime.

For open access, the optimal battery size tends to be smaller (260 MW) with longer duration (4 Hr) by comparison to the priority access battery (345 MW, 3 Hr). These results are intuitive. Priority access places a heavy burden of congestion on the marginal MW (see Appendix II, Fig. A2). Consequently with priority access, battery MW are prioritised over MWh. Conversely for the open access regime, the burden of curtailment is shared and therefore battery MWh are prioritised over MW.

Fig. 6 introduces rival batteries (dark blue dots). The Fig. 5 results reappear as light grey and light blue dots. The same relative pattern of battery configuration prevails. Open access induces smaller batteries (MW) with a longer duration (4 Hr), whereas priority access optimises with higher MW (260 MW) and lower duration (2 Hr), with reductions in welfare – with a summary provided in Table 8. In Fig. 6, the contrasting results between 'competitive rival' and 'coordinated portfolio' battery iterations are striking. Regardless of open or priority access, the *rival battery* produces results which reduce REZ productivity and welfare by comparison to a (non-rivalrous) portfolio battery.

To summarise the 300× iterations of simulations, Table 8 presents the dominant asset mix and output (10th percentile result). Note that battery impacts on VRE portfolio weightings differ subtly by access regime and industrial organisation. For open access, a portfolio battery induces additional wind (+100 MW) at the expense of solar (-50 MW) whereas a rival battery induces less wind (-50 MW) and solar capacity (-225 MW). For priority access, portfolio batteries materially reduce

Table 8
Portfolio allocation by access regime and industrial form (portfolio, rival).

Open Access		No Battery	Portfolio	Rival
Wind	MW	2050	2150	2100
Solar	MW	1400	1350	1125
Battery	MW	0	260	150
Hrs	MWh	0	4	4
Output	GWh/a	8700	8950	8400
Δ Welfare	$m	143	165	157
Priority Access		No Battery	Portfolio	Rival
Wind	MW	1775	1565	1755
Solar	MW	950	1290	800
Battery	MW	0	345	260
Hrs	MWh	0	3	2
Output	GWh/a	7100	7350	6900
Δ Welfare	$m	0	−3	−27

wind and increase considerably more solar, whereas the rival battery reduces both wind and solar.

To illustrate the evolution of the optimal portfolio battery in an open access regime, Fig. 7 runs the REZ Optimisation Model for a 4-h battery from 1 MW through to 260 MW (x-axis) with the REZ pre-populated with 2150 MW of wind and 1350 MW of solar (per Table 8). Total plant supernormal profits are measured on the LHS y-axis, while REZ congestion costs, which effectively measures the value of curtailed energy, is measured on the RHS y-axis.

Fig. 8 presents the battery size simulation scatterplots for the four scenarios, that is, by access regime and by industrial organisation (50 iterations per scenario). As the scatterplots tend to indicate, there is considerable variation in the optimal battery size for any given access regime and industrial form. But to summarise, priority access batteries cluster at higher MW capacity (average 305 MW across the 2 × 50 iterations) but with lower storage duration (average 2.7 h). Open access batteries tend to cluster at lower capacity (190 MW average across the 2 × 50 iterations) but with higher storage (average 4.1 h). It is also to be noted that entirely different renewable resources, or a material change to expected intraday price spreads, would invariably alter these findings.

Finally in Fig. 8, note that a 5th scenario has been highlighted – the *'Early Entrant'* battery at 585 MW and 3 h storage (by far the largest battery by capacity). This was a specific simulation generated by the REZ Optimisation Model under conditions of an under-subscribed REZ in which the anchor tenants were assumed to comprise 1400 MW wind, and 520 MW solar PV (i.e. the opening scenario used in Appendix II). This specific asset configuration was selected because with this level of VRE capacity, the REZ would operate in an unconstrained state (i.e. no congestion).

In this unconstrained state, the Model derived the optimal battery given sunk wind and solar plant capacity commitments of 1400 and 520 MW, respectively. With wind and solar constrained to these fixed MW capacities, the REZ Optimisation Model consistently selected a battery of 3 h duration, and with very little capacity variation (90th percentile 540–585 MW). This leads to an analysis of whether entry timing matters, in Section 5.2.

5.1. *Entry timing: Early vs. late entrant within a REZ*

An important insight from Section 5.1 Fig. 6 was that *rival batteries* within a REZ approaching its capacity limits competes with, and therefore may potentially crowd-out, new entrant VRE capacity. Another insight Section 5.1was *coordinated portfolio batteries* were smaller in capacity (MW) with more storage (MWh) than rival batteries. This raises a subsequent line of inquiry vis-à-vis entry timing. What are the welfare implications of early battery entrants? After all, battery development and entry times are a fraction of solar or wind projects (Clapin and Longden, 2024). Recall from Fig. 8 the optimal size of an early entrant, profit maximising battery under open or priority access was 585 MW, with 3 h duration under the following conditions:

- 1400 MW of wind (0 % curtailment),
- 520 MW of solar PV (0 % curtailment), and therefore,
- 585 MW, 3 Hour battery (0 % curtailment).

Using this zero-constrained plant stock as the starting point, the REZ Optimisation Model then explored two follow-on scenarios:

- Optimise VRE within the REZ under an open access regime, given the 585 MW, 3 Hour committed battery as a *coordinated (portfolio) asset*; and

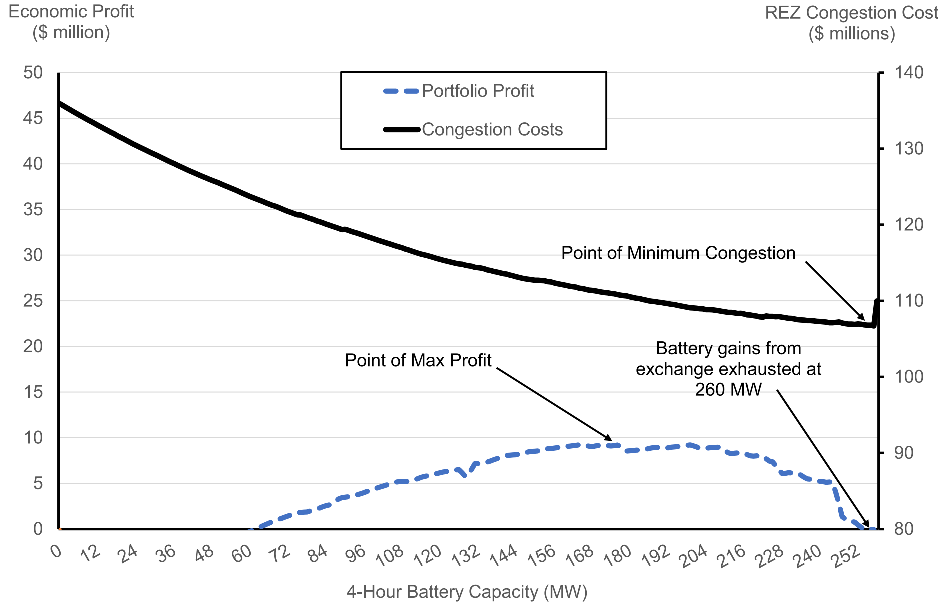

Figure 7. Evolution of 4 Hr portfolio battery (LHS) vs congestion costs (RHS).
Note in Fig. 7 economic profit is maximised at ~180 MW and is competed away as the battery approaches 260 MW. If the battery increases in capacity beyond 260 MW, it begins to contribute to (rather than relieve) congestion – the sharp jump in the congestion cost curve is clearly visible at the end of the x-axis.

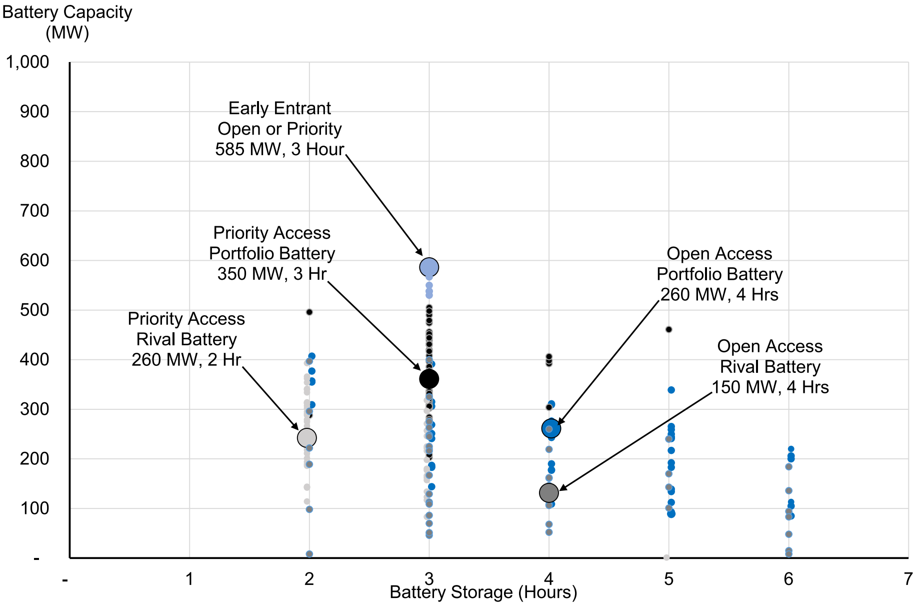

Figure 8. Battery size by access regime and industrial form.

- Optimise VRE within the REZ under a priority access regime, given the 585 MW, 3 Hour committed battery as a *rival entrant*.

These two scenarios were selected as they would provide bookends of early entrant results. As might be expected, results in Fig. 9 illustrate the early entrant battery crowds-out VRE plant capacity from its optimal state in either access regime. The intuition here is straightforward enough. Under an open access regime, the co-optimised battery tends to be smaller and longer in duration. An early entrant battery finds it profitable to *'oversizes itself'* in capacity (MW) compared to optimality, since there is unconstrained REZ line transfer capacity available. Furthermore, it under-sizes itself in storage (MWh) compared to optimality because there is no curtailed energy to arbitrage. This reduces welfare by ~$40 m per annum.

The intuition behind the priority access regime is similarly intuitive. The early entrant battery is larger in both capacity (MW) and storage (MWh) and in a priority access regime, crowds-out potential VRE entrants, with welfare once again deteriorating by ~$13 m per annum.

5.2. *Bilateral on-market transactions vs. government-initiated CfD transactions*

The final set of simulation iterations focus on policy implications for government-initiated CfD auctions. The Commonwealth Government of Australia initiated a policy known as the *Capacity Investment Scheme* or 'CIS' with its current form emerging in late-2023. The stated policy intent is to underwrite 27GW of wind, solar and dispatchable (storage) capacity to reach 82 % renewable market share in Australia's NEM by 2030. Thus far, successful CIS battery proponents have typically been 2–4 h in duration.

Storage in all its formats will become increasingly important for the NEM as system-wide curtailment rates rise. Storage of 6–8 h (and beyond) will be required (Gilmore, 2024). Accordingly, the final scenario set-up involves a benevolent government underwriting a 600 MW, 6-h battery within a REZ through the taxpayer-funded CIS.

To briefly summarise the workings of the CIS, like all other government-initiated CfD schemes, it is designed to underwrite revenues of a power project asset to enable proponents to optimise project finance. Risk averse project banks prefer government-initiated CfDs given the credit rating of sovereigns, which in turn can minimise credit spreads and maximise debt sizing (see Gohdes et al., 2022[14]).

In the Australian case, the CIS achieves such outcomes by awarding successful auction proponents with (taxpayer funded) put- and call option derivatives over the annual profitability of the asset-level 'Special Purpose Vehicle' – in this simulation, a battery. But because the CIS operates at the asset level, any CIS-sponsored battery will typically be a rival entrant because there is no basis upon which to originate the asset as a portfolio – the CIS operates at the SPV level and crucially - is exposed to a call option over profits[15]. Accordingly, government-initiated CfDs extracts such assets portfolio coordination. Simulation iterations for CIS-awarded batteries under the two access regimes are presented in Fig. 10, and contrast with smaller bilateral (on-market) portfolio battery transactions (reproduced from Fig. 5). Note in either access regime, a CIS battery reduces REZ productivity and welfare.

While not apparent from the data presented in Fig. 10, the annual profitability of the 600 MW, 6 Hour battery performs poorly compared to the 585 MW, 3 Hour early entrant. The early entrant earns supernormal profits of ~$4 m per annum. If the early entrant battery was increased from 3 to 6 h duration, profitability deteriorates to a -$22 m annual loss. Consequently, a CIS battery under these conditions requires taxpayer underwriting of -$22 m per annum given price data in Table 4.

However, in an open access regime profitable entry by wind and solar remains plausible but at the expense of the CIS-awarded battery. As wind and solar enter and approach their optimal levels (~2045 MW wind, ~1380 MW solar), the CIS battery incurs annual losses of -$33 m per annum. In this instance, consumers are worse off compared to the on-market result of 8950GWh/a as Fig. 10 illustrates. Furthermore, taxpayers are worse off through the -$33 m annualised losses associated with the CIS battery.

Such results suggest the location of any CIS battery auction transaction is critical in minimising near-term taxpayer losses (i.e. subsidies).

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[14] Although as Gohdes et al. (2022) note, whether this is optimal for taxpayers (where alternative BBB-rated on-market transactions exist) is an open question.

[15] A call option over profits makes sense when the put option is being funded by taxpayers. Nonetheless, the asset or SPV becomes a highly imperfect hedge for a portfolio.

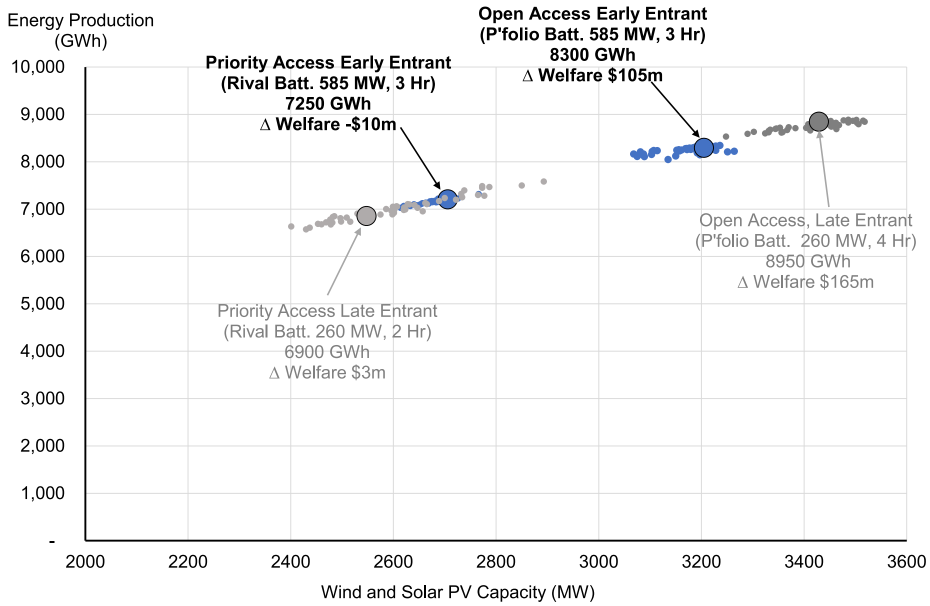

Figure 9. Early entrant battery vs. late entrant battery.

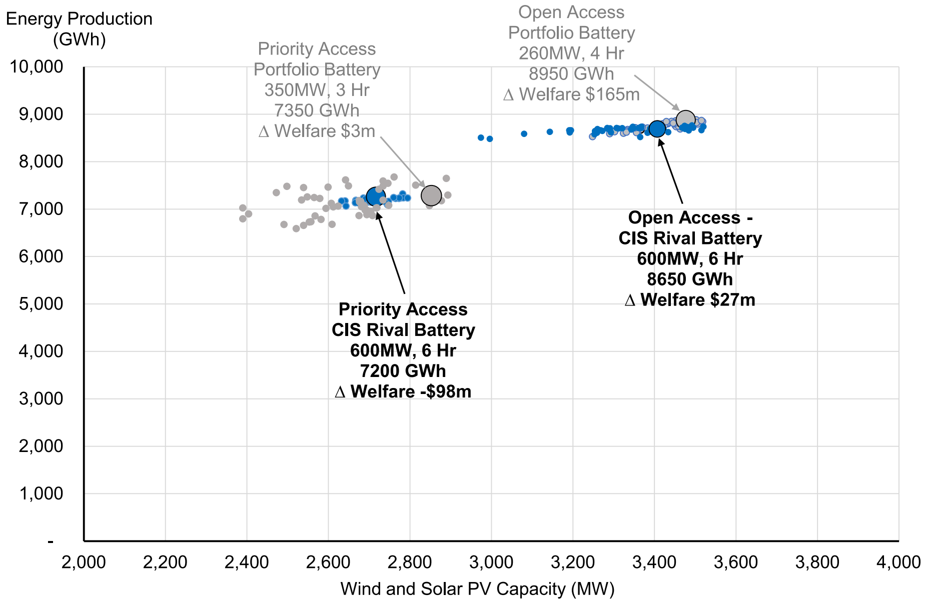

Figure 10. Govt-initiated CIS battery vs on-market portfolio batteries.

Locating the same CIS asset in an unconstrained area of the network, where wind and solar PV cannot be located, will produce better results and be more effective in reducing curtailment without crowding-out local VRE plant capacity.

6. Policy implications

There are four important implications for policymakers, and REZ investors, arising from the simulation scenarios presented throughout Section 4–5, as follows.

First, as an absolute general conclusion for a multi-zonal market setup like Australia's NEM, open access maximises welfare provided entry is regulated by capital markets at the efficient level. While results in Table 6 were unambiguous on this point, Fig. 6 helped further clarify this outcome across scenarios by comparing various combinations of optimised VRE and battery storage – including the changes in total welfare. Fig. 11 provides further weight by contrasting the REZ productivity of various scenarios, and reveals open access achieves materially higher output at the same unit cost (+/− \$1/MWh). The intuition here is that aggregate congestion under priority access (marginal rates of curtailment) is demonstrably lower than under open access (average rates of curtailment.

While at first glance it would seem logical that wind and solar average unit costs are minimised when congestion is minimised, such calculations exclude connection costs – and these are minimised when output is maximised. Accordingly, when the fixed and sunk costs of REZ transmission infrastructure are incorporated under a priority access regime, lower VRE unit costs are largely offset by higher (total) connection costs.

The second policy implication arising from Sections 4–5 is coordinated portfolio batteries are preferred to competitive rival batteries *within a REZ* regardless of access regime. Rival batteries compete for

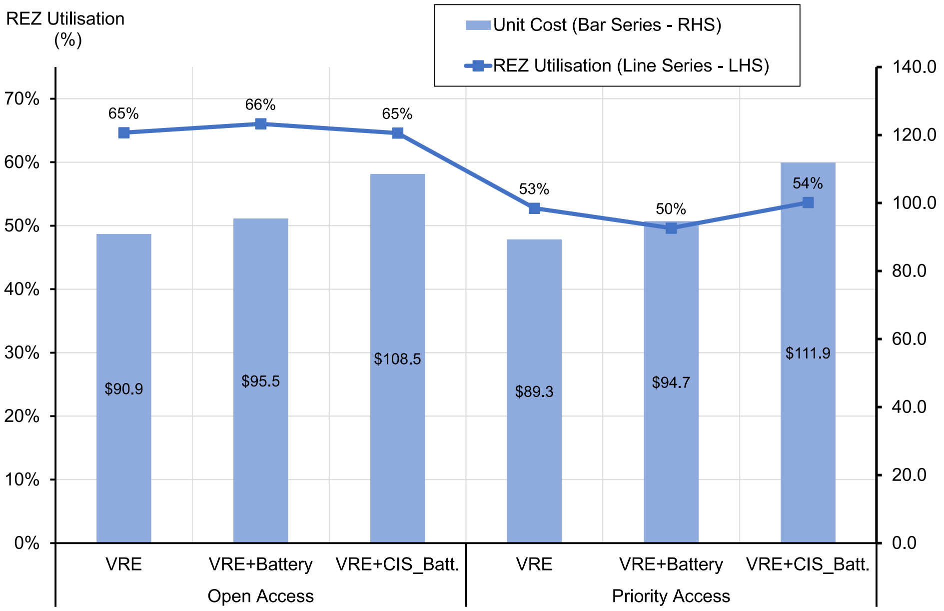

Figure 11. Comparison of REZ utilisation rates and unit costs.

scarce REZ transmission transfer capacity and aggravate congestion. Portfolio batteries would be sized, and scheduled, to alleviate congestion. Portfolio batteries do so by opportunistically charging during congestion events, and withholding dispatch during congestion events in either zonal or nodal market setups.

Third, early entrant batteries within an (uncongested) REZ may harm welfare through oversizing, ex ante, and crowding-out latter-entrant VRE plant. This is the case whether the entrant is a *coordinated portfolio battery*, or *competitive rival battery,* and regardless of access regime. The intuition here is that batteries do not generate renewable energy, they merely help move intermittent output through time. An oversized battery may drive reverse flows into a REZ during renewable lulls, and visibly compete for REZ line access during dispatch cycles. Either way, the effect may be the *crowding-out* of otherwise optimal levels of wind and solar plant capacity within a REZ.

The final policy implication relates to differences between on-market batteries, and government-initiated CfD auctions for batteries within a Special Purpose Vehicle (or single asset company). The scheme design constrains seamless internal transfers into portfolios. Consequently, CfD auctions of this type at the asset level *replicate* a rival battery. And as the second policy implication noted, rival batteries within a REZ are likely to harm welfare through aggravating congestion and crowding-out the optimal mix of wind and solar PV plant capacity regardless of access regime. Ironically, while wind and solar PV may fall short of their optimum, they may still enter at a rate that degenerates the profits of the government-initiated CfD battery, leaving both electricity consumers, and taxpayers, worse-off by comparison to on-market battery entrants within a REZ.

These policy implications need to be interpreted thoughtfully and in the context of the renewable resources (Fig. 2) and prices (Table 4). It is to be noted that the four policy implications outlined above were carefully caveated with the words *"within a REZ"* and in a multi-zonal market setup where it is assumed credible VRE resources exceed available transfer capacity. Yet as one reviewer noted, these same conditions exist for any closed VRE system with a bottleneck in transmission. Either way, the model insights *should not* be generalised or interpreted as suggesting all batteries, in all locations, and in all markets, should be coordinated – and that competition amongst battery proponents should somehow be eliminated.

The issue here is that REZs in Australia's NEM are designed, and declared, because they are locations which exhibit favourable wind and solar resources. Consequently optimising, and indeed maximising, the mix of wind and solar PV plant capacity should take priority *within a REZ*. There is nothing in Section 5 which suggests such a policy should apply across an entire multi-zonal (or nodal) market. And these findings need to be tempered for single zone or nodal market setups and the rich variation in spot market prices that can be expected to emerge as the plant stock changes over time. Axiomatically, competition amongst battery proponents is important. But batteries can be located throughout the wider transmission network locations.

7. Conclusion

REZs are an important policy initiative of NEM jurisdictional governments, designed to create the necessary hosting capacity for new VRE plant. Renewable proponents acting independently may otherwise drive duplicate network augmentations, which may raise costs above the minimum obtainable and over-activate community tension compared to a well-designed REZ. There should be no question that, even in a vast NEM region such as Queensland, there will be binding constraints to transmission developments due to the (*understandable*) limits of community acceptance. This is why REZ economics matters at all. It also means when a REZ is developed, optimal productivity should be well planned, and ideally achieved.

In this context, access regimes and the role of battery storage were analysed. The NEM's existing multi-zonal, 'open access' market setup was found to facilitate higher levels of VRE investment within the bounds of *'bankable'* levels of curtailment compared to a priority access regime. Open access shares the burden of curtailed energy with all plant facing the average rate of curtailment. Priority access ranks entry with plant following the marginal rate of curtailment.

Deriving the optimal plant stock within a REZ formed the balance of analysis, and the key insight was that as VRE investments approach the limits of lines transfer capacity, the role of battery storage needs to be considered carefully. If transfer capacity is congested, battery storage within the REZ may help by moving otherwise curtailed energy through space (transmission) and time (battery). What is less obvious is that rival batteries can aggravate congestion, or early-entrant portfolio batteries may be oversized – in either case crowding-out incremental VRE investments. Consequently, portfolio batteries are preferred to rivals, and latter-entrant batteries are preferred to early entrants *within a REZ*.

CRediT authorship contribution statement

Paul Simshauser: Writing – review & editing, Writing – original draft, Visualization, Validation, Software, Methodology, Investigation, Formal analysis, Data curation, Conceptualization.

Appendix I - Gonçalves and Menezes (2022) 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

Appendix II - The 'Average Rate of Curtailment' versus the 'Marginal Rate of Curtailment'

In order to illustrate the difference between the average rate and marginal rate of curtailment, the REZ Optimisation Model has been setup to simulate the outcomes for wind and for solar, as follows:

- Incumbent generation in the Model arbitrarily commences at 1400 MW wind and 520 MW solar PV. These levels have been selected because with this mix, REZ transmission line congestion is zero;
- The REZ Optimisation Model then iterates 300 times, with each iteration progressively increasing the combined installed VRE plant capacity from 1400 to 2200 MW (wind), and 520-1150 MW (solar PV).

Model results for each of wind and solar, illustrating the difference between fleet potential, fleet average, and fleet marginal Annual Capacity Factors, appear in Figs. A1 and A2. respectively. In each, the y-axis depicts Annual Capacity Factor and the x-axis measures installed capacity.

Focusing on Fig. A1 at the origin (where installed wind capacity = 1400 MW), output is unconstrained and as a result, potential output of 35 % ACF exactly equals practical output. However, as wind capacity progressively increases from 1400 to 2200 MW along the x-axis, average curtailment slowly increases due to transmission line congestion. Average production losses culminate at ~5 % of output by the end of the data series at 2200 MW, meaning the fleetwide *average ACF* has reduced by 5 %, from 35.0 % to 33.2 % as marked. To be clear, this is the *'average rate of curtailment'*.

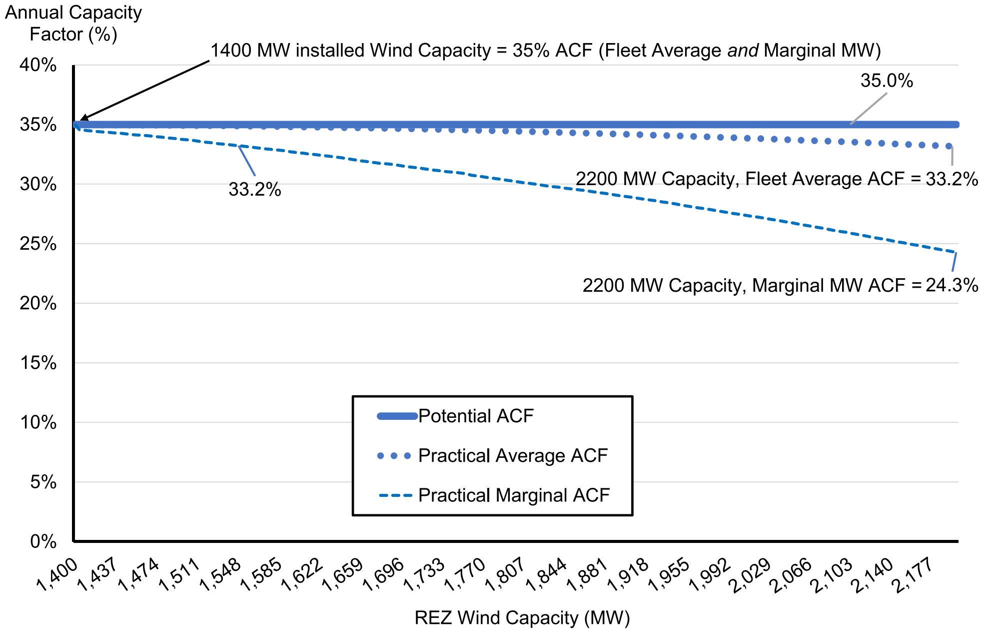

Fig. A1. Wind average vs. marginal rate of curtailment.

Now consider the productivity of the marginal MW installed in Fig. A1. The very last MW added along the x-axis incurs marginal production losses of ~30 % of output, with an ACF of 24.3 % as marked. In this sense, the 2200th MW is only 70 % as productive as the first 1400 MW added. Equivalent results can be seen for solar PV in Fig. A2.

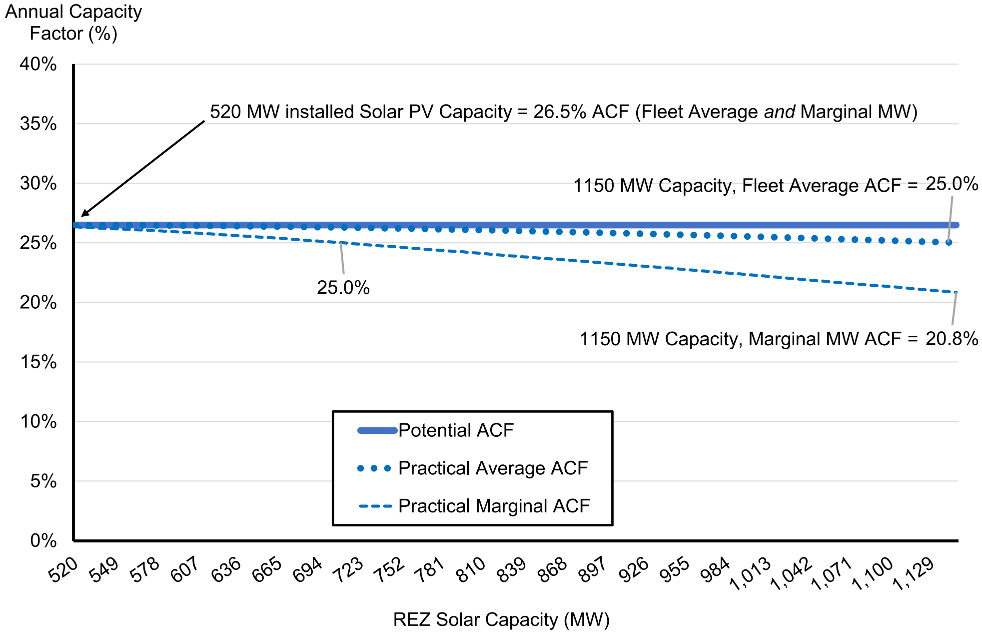

Fig. A2. Solar PV average vs. marginal rate of curtailment.

What are the policy implications of these results? In a multi-zonal market setup with an open access regime like Australia's NEM, the burden of VRE curtailment is shared amongst producers and so it is the *average rate of curtailment* that matters for renewable plant investors. If the NEM switched to a priority access regime, the burden of curtailment would switch and follow a strict rank order according to entry timing (i.e. last-in, first-off), and so it would be the *marginal rate of curtailment* that would matter for renewable investors (which is analogous to Locational Marginal Prices with long-dated Financial Transmission Rights). Recall, it is assumed entry is regulated by the capital markets and in particular, risk averse project banks and their tolerance for curtailment.

In practical terms, in a multi-zonal market setup, open access facilitates more VRE investment within a REZ, the extent of which is regulated by capital markets. Fig. A1 highlights the point at which curtailment reaches 5 % of output (or ~ 33.2 % ACF). If 5 % lost production is the curtailment rate that capital markets will tolerate, and Power Purchase Agreements (PPAs) are priced efficiently at the margins, open access implies 2200 MW of 'bankable wind' investments in the Western Downs REZ as illustrated by the thick dotted line series. Conversely, Fig. A1 suggests for a priority access regime (marginal rate of curtailment), only 1550 MW of wind is bankable as illustrated by the thin dashed line series. Again, equivalent results can be seen for solar with Fig. A2.

Appendix III

Optimal wind & solar PV capacity – 'open access'

	Wind	2050 MW	2017	2018	2019	2020	2021	TOTAL
1	Potential Wind Output	(GWh)	5837	6714	6362	6289	6214	31,417
2	Practical Wind Output	(GWh)	5581	6275	6002	6020	5925	29,802
3	REZ Congestion	(GWh)	257	439	359	270	289	1614
4	Energy Curtailed	(% of Prod)	4.4 %	6.5%	5.7 %	4.3 %	4.7 %	5.1 %
5	Economic Wind Output	(GWh)	5574	6267	5952	5853	5668	29,314
6	Spill -ve spot prices	(GWh)	7	7	50	167	257	488
7	Energy Spilled	(%)	0	0	0	0	0	0
8	Total Curtail & Spill	(GWh)	264	447	410	437	546	2102
9	Total Curtail & Spill	(% of Prod)	4.5%	6.7 %	6.4 %	6.9 %	8.8 %	6.7 %
10	Potential ACF	(% - ACF)	32.5 %	37.4 %	35.4 %	35.0 %	34.6 %	35.0 %
11	Economic ACF	(% - ACF)	31.0 %	34.9 %	33.1 %	32.6 %	31.6 %	32.6 %
12	ACF Loss	(% - ACF)	1.5 %	2.5 %	2.3 %	2.4 %	3.0 %	2.3 %
13	Revenue	$m	677.2	589.0	542.2	312.3	623.2	2743.9
14	Costs	$m	518.4	518.4	518.4	518.4	518.4	2591.9
15	REZ Charges	$m	30.3	30.3	30.3	30.3	30.3	151.6
16	Economic Profit	$m	128.5	40.3	−6.5	−236.4	74.5	0.4
17	Unit Revenue	($/MWh)	121.5	94.0	91.1	53.4	109.9	93.6
18	Unit Cost	($/MWh)	93.0	82.7	87.1	88.6	91.4	88.4
19	REZ Cost	($/MWh)	5.4	4.8	5.1	5.2	5.3	5.2
20	Economic Profit	($/MWh)	23.1	6.4	−1.1	−40.4	13.1	0.0
	Solar PV	**1400 MW**	2017	2018	2019	2020	2021	TOTAL
21	Potential Solar Output	(GWh)	3266	3342	3326	3184	3140	16,258
22	Practical Solar Output	(GWh)	3092	3042	3077	3001	2934	15,146
23	REZ Congestion	(GWh)	174	300	249	183	206	1111
24	Energy Curtailed	(% of Prod)	5.3 %	9.0 %	7.5%	5.7 %	6.6 %	6.8%
25	Economic Solar Output	(GWh)	3087	3033	2945	2672	2449	14,186
26	Spill -ve spot prices	(GWh)	4	9	132	329	485	960
27	Energy Spilled	(%)	0	0	0	0	0	0
28	Total Curtail & Spill	(GWh)	178	309	381	512	691	2071
29	Total Curtail & Spill	(% of Prod)	5.5%	9.3 %	11.4 %	16.1 %	22.0 %	12.7 %
30	Potential ACF	(% - ACF)	26.6 %	27.3 %	27.1 %	26.0 %	25.6 %	26.5 %
31	Economic ACF	(% - ACF)	25.2 %	24.7 %	24.0 %	21.8 %	20.0 %	23.1 %
32	ACF Loss	(% - ACF)	1.5 %	2.5 %	3.1 %	4.2 %	5.6 %	3.4 %
33	Revenue	$m	426.6	265.3	233.4	120.2	168.8	1214.3
34	Costs	$m	227.6	227.6	227.6	227.6	227.6	1138.0
35	REZ Charges	$m	14.7	14.7	14.7	14.7	14.7	73.4
36	Economic Profit	$m	184.4	23.0	−8.9	−122.1	−73.5	2.9
37	Unit Revenue	($/MWh)	138.2	87.5	79.2	45.0	68.9	85.6
38	Unit Cost	($/MWh)	73.7	75.0	77.3	85.2	93.0	80.2
39	REZ Cost	($/MWh)	4.8	4.8	5.0	5.5	6.0	5.2
40	Economic Profit	($/MWh)	59.7	7.6	−3.0	−45.7	−30.0	0.2
41	Portfolio Output (Line 5 + 25)	(GWh)	8661	9300	8898	8525	8117	43,501
42	Portfolio Profit (Lines 6 + 36)	$m	312.9	63.3	−15.4	−358.5	1.0	3.3

Optimal wind & solar PV capacity – 'priority access'

	Wind	1775 MW	2017	2018	2019	2020	2021	TOTAL
1	Potential Wind Output	(GWh)	5054	5813	5508	5446	5381	27,202
2	Practical Wind Output	(GWh)	4983	5662	5400	5364	5289	26,698
3	REZ Congestion	(GWh)	71	152	109	81	92	505
4	Energy Curtailed	(% of Prod)	1.4 %	2.6 %	2.0 %	1.5%	1.7 %	1.9 %
5	Economic Wind Output	(GWh)	4977	5655	5350	5200	5031	26,214
6	Spill -ve spot prices	(GWh)	6	6	50	164	257	483
7	Energy Spilled	(%)	0	0	0	0	0	0
8	Total Curtail & Spill	(GWh)	77	158	159	245	349	988
9	Total Curtail & Spill	(% of Prod)	1.5%	2.7 %	2.9 %	4.5%	6.5%	3.6 %
10	Potential ACF	(% - ACF)	32.5%	37.4 %	35.4 %	35.0 %	34.6 %	35.0 %
11	Economic ACF	(% - ACF)	32.0 %	36.4 %	34.4 %	33.4 %	32.4 %	33.7 %
12	ACF Loss	(% - ACF)	0.5 %	1.0 %	1.0 %	1.6 %	2.2%	1.3 %
13	Revenue	$m	605.7	531.1	485.2	276.4	547.9	2446.3
14	Costs	$m	448.8	448.8	448.8	448.8	448.8	2244.2
15	REZ Charges	$m	32.5	32.5	32.5	32.5	32.5	162.5
16	Economic Profit	$m	124.4	49.8	3.9	−204.9	66.5	39.6
17	Unit Revenue	($/MWh)	121.7	93.9	90.7	53.2	108.9	93.3
18	Unit Cost	($/MWh)	90.2	79.4	83.9	86.3	89.2	85.6

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	Wind	1775 MW	2017	2018	2019	2020	2021	TOTAL
19	REZ Cost	($/MWh)	6.5	5.7	6.1	6.2	6.5	6.2
20	Economic Profit	($/MWh)	25.0	8.8	0.7	−39.4	13.2	1.5
	Solar PV	**950 MW**	2017	2018	2019	2020	2021	TOTAL
21	Potential Solar Output	(GWh)	2216	2268	2257	2161	2131	11,032
22	Practical Solar Output	(GWh)	2181	2190	2201	2120	2082	10,774
23	REZ Congestion	(GWh)	35	78	56	40	49	258
24	Energy Curtailed	(% of Prod)	1.6 %	3.4 %	2.5%	1.9 %	2.3 %	2.3 %
25	Economic Solar Output	(GWh)	2178	2184	2106	1883	1728	10,079
26	Spill -ve spot prices	(GWh)	3	6	94	237	354	695
27	Energy Spilled	(%)	0	0	0	0	0	0
28	Total Curtail & Spill	(GWh)	38	84	150	278	403	953
29	Total Curtail & Spill	(% of Prod)	1.7 %	3.7 %	6.7 %	12.9 %	18.9 %	8.6 %
30	Potential ACF	(% - ACF)	26.6 %	27.3 %	27.1 %	26.0 %	25.6 %	26.5%
31	Economic ACF	(% - ACF)	26.2%	26.2%	25.3 %	22.6 %	20.8%	24.2%
32	ACF Loss	(% - ACF)	0.5%	1.0 %	1.8%	3.3 %	4.8%	2.3 %
33	Revenue	$m	299.0	191.1	166.4	84.4	118.2	859.1
34	Costs	$m	154.4	154.4	154.4	154.4	154.4	772.2
35	REZ Charges	$m	12.5	12.5	12.5	12.5	12.5	62.5
36	Economic Profit	$m	132.1	24.1	−0.5	−82.6	−48.7	24.3
37	Unit Revenue	($/MWh)	137.3	87.5	79.0	44.8	68.4	85.2
38	Unit Cost	($/MWh)	70.9	70.7	73.3	82.0	89.4	76.6
39	REZ Cost	($/MWh)	5.7	5.7	5.9	6.6	7.2	6.2
40	Economic Profit	($/MWh)	60.6	11.0	−0.3	−43.8	−28.2	2.4
41	Portfolio Output (Line 5 + 25)	(GWh)	7155	7839	7456	7083	6759	36,293
42	Portfolio Profit (Lines 6 + 36)	$m	256.4	73.9	3.3	−287.5	17.8	64.0

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