Electricity storage and decarbonisation of electricity supply: the case of South Australia

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Abstract

In 2023 the State of South Australia (SA) had twice as much variable renewable electricity (VRE) in its electricity mix as the country (Portugal) with the highest proportion globally. Electricity storage is also growing quickly but is not yet meaningful in decarbonising electricity supply. More VRE and much more storage is needed to achieve policy objectives. Will it be affordable and economically sensible? This paper develops a time-series analysis assuming storage is operated to maximise the displacement of dispatchable fossil fuel generation. The analysis suggests that raising VRE penetration in SA to around 90% of end use consumption, through VRE expansion and storage, will be affordable and economically sensible. However, the declining yield from storage suggests that displacement of the last 10% of fossil fuel by storing and later using renewable electricity, will be achieved at implied carbon abatement costs far above contemporary estimates of the Social Cost of Carbon. Neither will it be affordable. Very large amounts of storage are needed to come close to fully decarbonising supply, because most of the storage is very seldomly used. A 20-fold reduction in the currently expected cheapest long duration storage cost is needed to make full decarbonisation through storage affordable and economically sensible. Since such a steep decline is unforeseeable now, policy might be expected to prioritise decarbonisation in other parts of the economy before pursuing the final 10 % of electricity decarbonisation, through storage. Actively pursuing other (non-storage) avenues for decarbonisation will also be valuable. This includes encouraging a stronger temporal association between electricity demand and VRE supply, pursuing low or zero carbon dispatchable generation and seeking to harness storage in electric vehicles for use in the electricity grid.

Keywords: electricity storage; variable renewable electricity; decarbonisation of electricity supply

JEL Classifications: C22, C41, C63, L52, Q41, Q48, Q51, Q55

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1. Introduction

In 2023 76% of the electricity produced in South Australia (SA), one of five regional markets that together make up the National Electricity Market (NEM) in Australia, came from variable renewable energy (VRE): wind farms, rooftop solar and solar farms, in that order[i]. SA's VRE share is more than double that of the next highest state in Australia (Victoria) and more than double that in the country with the highest proportion globally (Portugal).[ii]

SA also has sufficient storage, in lithium batteries, to meet about one-sixth of its annual peak demand. Storage is growing rapidly: five time as much lithium storage as in the first grid-connected lithium battery commissioned in SA in 2018 (which was the largest of such batteries globally when commission) is operational. While storage in SA is now providing useful frequency response services to the power system and insurances services to transmission networks and is used to a small extent on customers' premises, it still has an inconsequential role in decarbonisation of electricity in SA: gas- and diesel-powered generation in SA and coal-fired generation in neighbouring Victoria remains essential in compensating for the variability of VRE in SA.

Further decarbonisation of electricity supply in SA will require more VRE, and also much more storage to displace (dispatchable) fossil-fuel generation. The South Australian Government's aspiration is 100% "net" renewables by 2030[iii] and the Australian Government has announced major policy support for continued expansion of VRE and storage[iv]. But how much dispatchable generation will additional storage displace, and will it be affordable and economically sensible to build it? This paper presents a time-series analysis of storage and VRE expansion in SA, motivated by these questions.

There is a rich optimisation-focussed literature concentrating mainly on the United States and Europe, on the role of storage in the decarbonisation of electricity supply. A common conclusion from this literature is that storage power capacity is linear in VRE penetration, but storage energy capacity is exponential in VRE penetration (Cebulla et al., 2018). Apriori this is expected: as VRE penetration increases, storage becomes useful not just for regular daily shifting of solar surpluses to meet night-time demands, but also for shifting VRE from times of seasonal surplus to times of seasonal scarcity. While small amounts of storage can regularly deliver diurnal shifts, large amounts of rarely used storage is needed to compensate for seasonal variability in VRE supply. Nevertheless, the literature presents widely different conclusions on the nature of the exponential relationship. This reflects differences in methodology, in the studies' many input assumptions and in VRE availability and the profile of electrical demand of the specific regions that are examined.

In this analysis, storage is assumed to be operated to maximise the displacement of fossil fuel generation. This means that if VRE exceeds demand, the surplus is stored until the storage is full; and stored electricity is drawn upon in preference to fossil-fuelled generation or imports, whenever VRE falls short of demand. This assumption reflects the selection of commercially available chemical storage (which dominates existing and proposed storage facilities) and which has low round-trip losses. VRE and storage technology costs used here are based on official estimates from Australia's National Science Agency (see (Graham et al., 2023)).

SA's already high VRE penetration means plausible projections of VRE production can be made by proportionately expanding existing VRE capacity, eliminating the uncertainty associated with primary resource modelling.

The analysis here avers model-based optimisation (the literature shows this can yield widely varying results) in favour of estimating outcomes (decarbonisation contribution and cost) associated with different VRE and storage expansion scenarios, and assuming unchanged end-use demand. This time-series analysis makes visible the storage outcomes and consequential impacts on the substitution of fossil fuel generation for storage, in hourly, 8 hourly, 7 day and monthly time slots. Outcomes are valued in terms of incremental annual costs and implicit carbon abatement costs. Policy implications are drawn in some respects using the Social Cost of Carbon (SCC, - see (Environmental Protection Agency (U.S.), 2022) as the measure.

Various arguments can be made as to why the estimates derived in this analysis either under-estimate or over-estimate the effect of storage on decarbonisation and the consequential costs and implied abatement cost. On balance, the arguments on under-estimation seem more plausible.

The main conclusion from this analysis is that expansion of VRE and storage so that VRE produced in SA accounts for around 90% of SA end-use electrical demand (up from 71% in 2023) is possible at implied carbon abatement costs below the SCC. Nonetheless substantial policy support will be needed to deliver this outcome since spot markets are unlikely to provide sufficient revenues to compensate very rarely used storage. Beyond 90% VRE penetration, very large amounts of rarely used storage is needed for seasonal displacement of fossil fuel generation.

The paper is set out as follows: the next section describes the South Australian wholesale electricity market covering supply, demand, interconnection, storage, and prices; Section 3 reviews relevant literature followed by a description of the analytical method; Section 5 presents the main results followed by a discussion of those results. The final section concludes and draws out policy implications.

2. Description of the South Australian wholesale electricity market

The description here draws on demand, supply and price data published by AEMO[v] and extracted from data portal www.v-nem.org.

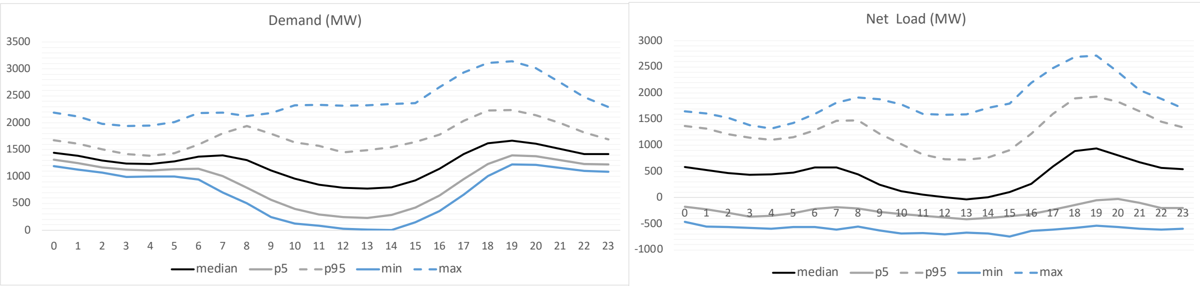
Operational Demand and Net Load

Figure 1a and 1b below presents on hourly statistical measures of Operational Demand[vi] (OD) and Net Load (Operational Demand less Variable Renewable Energy) for the 8760 values of these variables in each hour of the year ending 31 August 2023. Net Load (NL) measures the demand left to be supplied by a dispatchable generating source such as hydro, gas, diesel, or batteries.

While the median hourly OD does not vary widely, it is notable that the minimum hourly OD reached just 5 MW at 14h00 as behind-the-meter rooftop solar almost met the entire South Australian demand. By contrast the maximum demand reached 3,141 MW at 19h00 when rooftop solar would have had no effect in reducing OD.

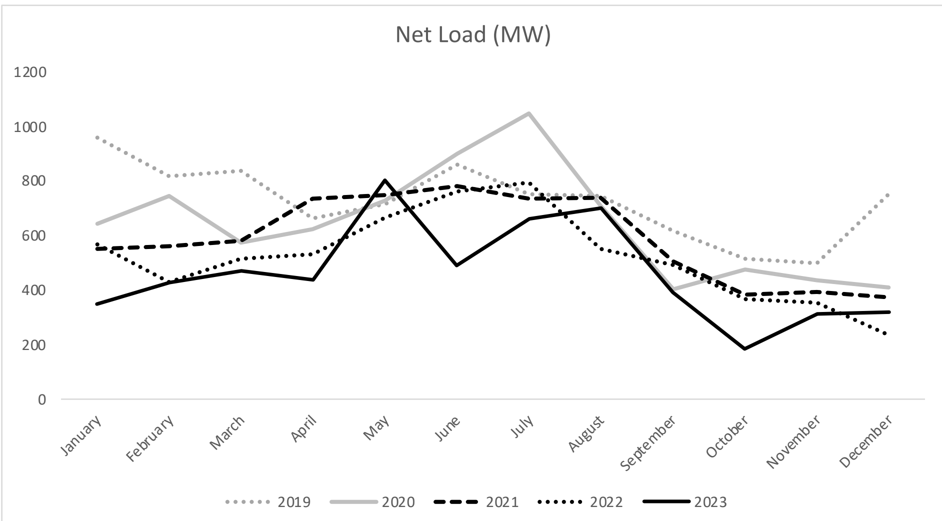
Figure 1b shows that the minimum hourly Net Load was negative for all hours and reached a minimum of -744 MW at 15h00. By contrast the maximum hourly value of NL was 2,690 MW at 18h00. The median NL was -29 MW at 13h00 and just 4 MW for the hours either side of it.

Figure 1a and 1b. Hourly statistics on Operational Demand (1a) and Net Load (1b) for year to 31 August 2023



As renewable electricity has expanded in South Australia, so NL has declined. The minimum annual value of NL was positive in 2013. Since then, it has declined to a minimum value of -862 MW in 2023. This trend can also be seen in Figure 2 which shows the median monthly value of NL in each year from 2019 to 2023, normalised by the highest median monthly NL. In 2023, NL was at its lowest ever monthly level in 9 of the 12 months of that year. In 2022, NL was then at its lowest ever monthly level in 10 of the 12 months of that year. The monthly pattern of NL is reasonably consistent: rising in the last months of autumn (May) and then high for the three months of winter (June to August) declining for spring and summer until early/mid-autumn. Nevertheless, reasonable levels of monthly variation are visible: in 2023, NL peaked in May, above the level of the previous 5 years but was then way below the level of the previous 5 years in June.

Figure 2. Median monthly Net Load normalised by highest median monthly Net Load 2019 to 2023



Comparing the 5-minute Operational Demand in South Australia with that in Victoria reveals a correlation (Pearson Product Moment) of 74%. NL, at 61%, is less highly correlated. The difference is likely to mainly reflect the much higher proportion of renewable electricity in South Australia (71% of South Australian end use demand) compared to 37% in Victoria in 2023.

Supply

Figure 3a and 3b presents hourly statistics on electricity production from VRE and gas, which together accounted for 98.6% (75.1% and 23.5% respectively) of the electricity produced in South Australia in 2023. Batteries (0.5%) and diesel generation (0.2%) accounted for the remainder. There were 23 operational wind farms, with no single farm significantly larger than others. There were 20 operational solar farms, but just four accounted for 90% of production. South Australia has the highest per capita penetration of rooftop solar in Australia and by far the highest share expressed as a percentage of grid demand (25% in South Australia compared to 14%/11%/11% and 3% in Queensland/New South Wales/Victoria/Tasmania respectively).

Figure 3a shows stable median VRE values from 18h00 to 6h00 at around 800 MW, and then a parabolic bulge during the day because of, mainly, rooftop solar generation. However, the hourly p5 and p95 values show a big, but consistent difference of around 1,600 MW from 18h00. The biggest difference in VRE production in any hour of the day was 3,026 MW, at 11am.

Figure 3b shows gas generation typically running down to very low levels from 10h00 to 15h00 but rising to meet evening peaks and then running down to low but reasonable constant levels until 10am. Like VRE, there is a big difference between the p5 and p95 levels, but unlike VRE it is not consistent across hours – the median during the evening peaks is about twice its level in the rest of the day.

Figure 3a and 3b. Hourly statistics on variable renewable electricity (VRE) (3a) and gas generation (3b) for year to 31 August 2023

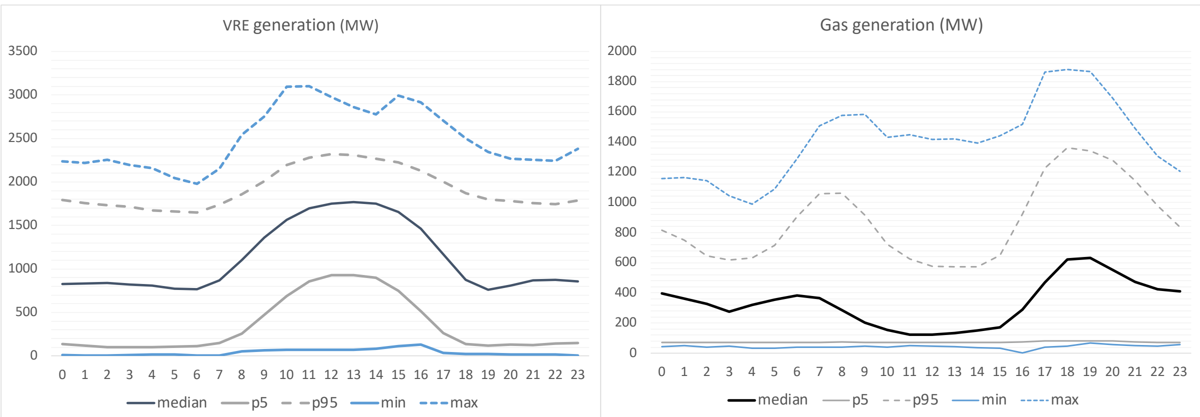
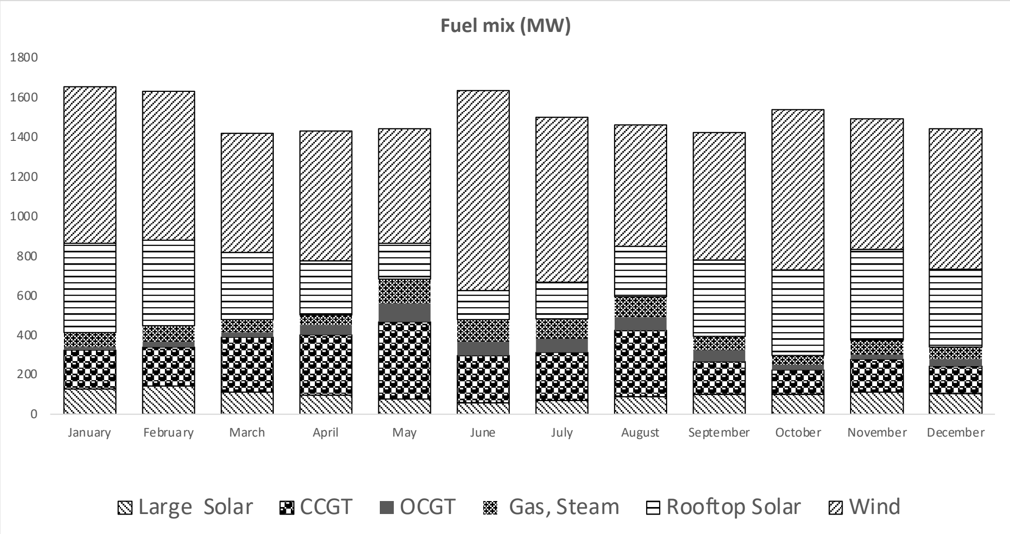


Figure 4 shows a clear seasonal variation in solar generation (winter months are about a third of summer months), approximately offset by gas generation (winter months about twice summer months). Wind generation does not show strong summer/winter difference, but wind generation is clearly lower in autumn than other seasons.

Figure 4. Monthly average production by fuel type in 2023

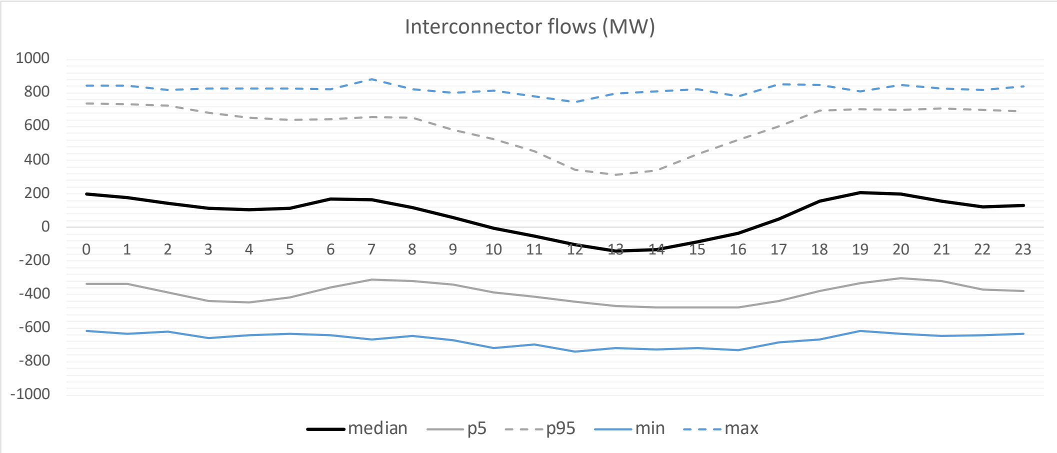


Diesel generation accounted for 31 GWh (0.2% of total production) with 12 units able to produce electricity from diesel (some of which are co-fired with gas). While diesel has a small role in energy production it played a large role in the provision of power with monthly peak production ranging between 150 MW and 410 MW usually at the time of the evening peak.

Interconnection

South Australia is connected to Victoria through a 200 kV DC interconnector (Murraylink) and a 500 kV AC interconnector (Heywood). A third interconnector to NSW (EnergyConnect) is currently under construction. Figure 5 presents hourly statistic on the net interconnector flows for the year to 31 August 2023 (positive values are imports). The chart shows that SA typically (median) exports from 10h00 to 16h00 and imports in the remaining hours. Average hourly net import in 2023 was 50 MW on Murraylink and 44 MW on Heywood giving annual net import of 94 MW. This is 7.3% of South Australian average OD in 2023 (1,282 MW). However, at times of peak hourly import (around 800 MW) or peak hourly export (around 650 MW) the interconnectors have evidently had a much bigger role in South Australia's supply and demand. Examination of the 5-minute data reveals that aggregate annual net import was 780 GWh (imports of 1868 GWh against export of 1087 GWh)[vii]**.** As might be expected considering SA spot prices (see Figure 7) the weighted average price received for exports was $4/MWh, but the weighted average price received for imports was $139/MWh.

Figure 5. Hourly statistics on interconnector flows for year to 31 August 2023



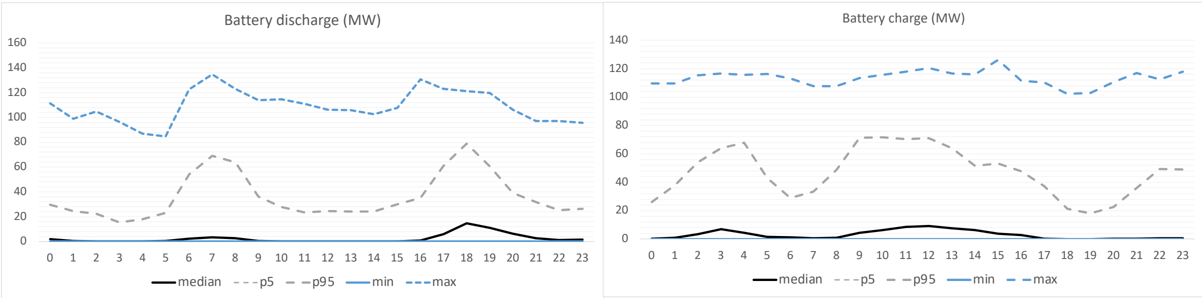
Correlating demand, wind generation, solar generation, VRE and prices in SA with demand, wind generation, solar generation, VRE and prices in Victoria (adjusted for the 30-minute time difference) reveals high correlation in 5-minute values of demand (74%), reasonable correlation in wind (55%), extremely high correlation in solar generation (89%) and high correlation in VRE (69%) and weak correlation in prices (33%). However, there is an extremely high correlation of the median / average hourly price for the 24 hours in a day in SA and Victoria (99%/97%).

Storage

South Australia became the focus of global interest in 2017 with the rapid development of the first stage (100 MW) of the Hornsdale Power Reserve ("Tesla big battery"), at that time the largest such battery globally, and which was commissioned just 63 days after the grid connection agreement was signed[viii]. Since that time, it has been expanded 50% and a further seven batteries built (of which 4 are embedded batteries smaller than 6 MW and one has power capacity equal to 251 MW) so that total storage power capacity at the end of 2023 was 471MW and energy capacity of 521MWh. At the time of writing one battery (42 MW/84 MWh) has been "committed" to be developed and a further 3 batteries (320MW/701 MWh) are "anticipated" and 39 batteries (5,589 MW/6,634MWh) have been "publicly announced"[ix].

Figure 6 presents hourly statistics on battery discharge and charge (excluding the 250 MW Torrens Island BESS which is operational and in testing but had not yet been commissioned by the end of the study period). The median shows the expected charging when prices are likely to be low (at night and when solar is abundant) and discharging when high (when fossil fuel generation is abundant).

Figure 6. Hourly statistics on battery discharge and charge for the year to 31 August 2023

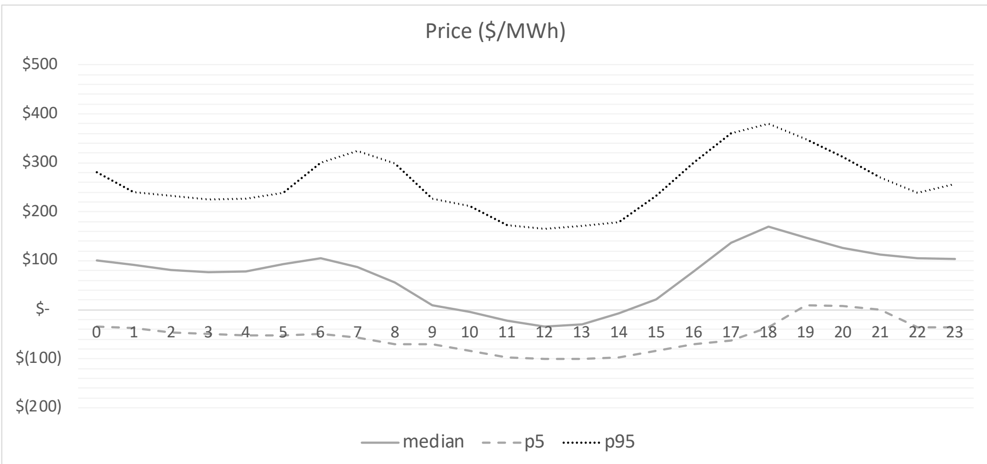


Wholesale prices

Wholesale (spot) prices are determined every five minutes in the mandatory (for generators bigger than 30 MW) spot market. A single price is paid for production source from the transmission system and paid to all grid-connected generators in South Australia that are dispatched by AEMO. Formally the price is calculated as the highest price of the generator dispatched to meet demand at the Adelaide Regional Reference Node.

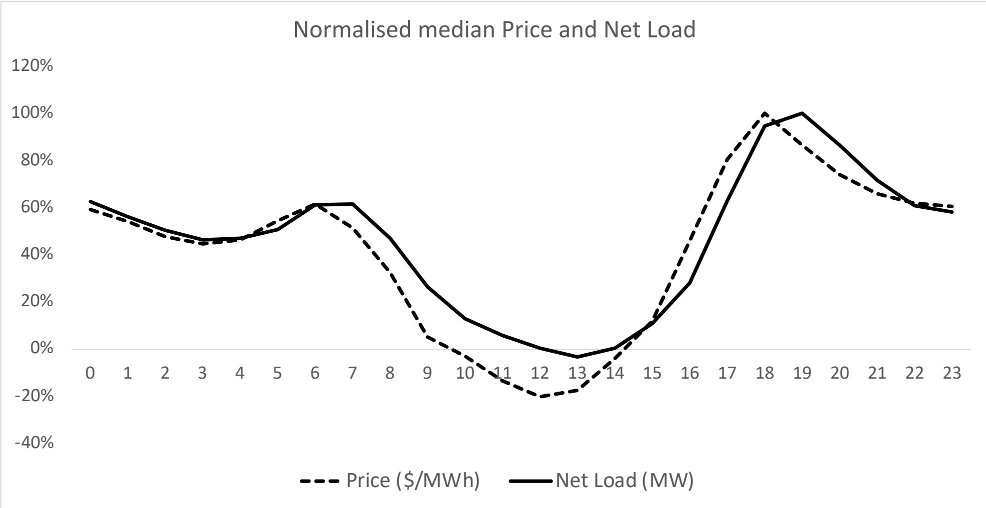
Figure 7 presents statistics on the South Australian spot price for the year to 31 August 2023. The minimum hourly price is typically around $-1000/MWh, and the maximum hourly price is rises to $16,600/MWh for several hours and is not less than $1000/MWh in any hour. The maximum and minimum hourly values are not shown, as the scaling would hide the information on prices between p5 and p95. Most notably, the median price from 10h00 to 14h00 is negative, corresponding to the periods of low NL, as shown in Figure 1b.

Figure 7. Hourly statistics on spot price ($/MWh) for year to 31 August 2023



The 5-minute values of NL are reasonably strongly correlated with Price (55%). However the hourly median values of NL and price are very strongly correlated as shown in Figure 8, and the average price during the 24,527 five minute intervals when NL was negative was negative $18/MWh (it was positive for 8,575 of the 24,527 five minute intervals when NL was negative and the average price in these times was $17/MWh)

Figure 8. Hourly statistics of average spot price ($/MWh) and Net Load (normalised by hourly maxima) for year to 31 August 2023



3. Relevant literature

In a survey of the (mainly) optimisation-based research on the relationship between VRE penetration and storage (Cebulla et al., 2018) concludes that (storage) power capacity is linear in VRE penetration but exponential in energy capacity. (Cebulla et al., 2017) explains the exponential relationship as attributable to the increasing demand for storage as VRE grows: for systems with very high renewable shares, storage needs to cover predictable diurnal variation but also extended periods of low renewable production. However, views on the nature of the exponential relationship vary widely. For example, in the 17 studies cited in (Cebulla et al., 2018), for a VRE share of around 80%, storage requirements range from 15 to 530 GW (0.2 to 6 TWh) for the United States, 10 to 350GW (0.2 to 22 TWh) for Europe, and 8 to 140 GW (0.05 to 83 TWh) for Germany.

In Australia (Rey-Costa et al., 2023) apply an optimisation model of the NEM to conclude that no storage will be needed if VRE is expanded to be able to produce three times (energy) demand over their study period (i.e. two thirds of VRE production is spilled) and they ignore transmission. Only expanding VRE production to twice (energy) demand will, they conclude, require just 128 GWh of storage for full decarbonisation. In a series of weekly updated posts on Twitter, industry executive David Osmond presents time-series modelling of the NEM that concludes that with suitable scaling of renewable electricity "just" 120 GWh (24 GW) of storage is needed to fully decarbonise electricity supply[x]. As with Rey-Costa et al and many of the optimisation studies in Europe and the United States included in the review in (Cebulla et al., 2018), infinite transmission - "brass plate" - (or, equivalently, costless transmission expansion) is assumed. Yet it is now clear in Australia, as elsewhere, that transmission expansion is a major impediment to the expansion of renewable electricity, even in those parts of the world where limited renewable investment has so far occurred (International Energy Agency, 2023).

The Australian Energy Market Operator estimates that 650 GWh of storage will be needed in the NEM in a fully decarbonised system (AEMO, 2022), although a large part of this is the potential energy in stored water in the upper reservoir of a pumped hydro facility, "Snowy 2.0", currently being developed.

(Houssainy & Livingood, 2021) suggests the main conclusion in the literature on the relationship between VRE penetration and storage requirement is that storage requirement is linear in power capacity and exponential in energy capacity but concludes that there is no consensus on the required energy storage capacity for operating and maintaining a 100% renewable energy portfolio. Comprehensive modelling of multi-scale energy storage technologies remains a major challenge towards achieving complete understanding of the value of storage technologies in achieving carbon-free or high renewable power systems (Guerra, 2021).

A survey of the literature identifies many methodological, assumption, conceptual and contextual differences to explain the widely varying conclusions on the quantity of storage needed to ensure reliable supply in systems dominated by VRE. In their study of the German power system (Ruhnau & Qvist, 2022) conclude that storage requirement estimates positively relate to the study period (number of years of historic data). Similarly, (Dowling et al., 2020) conclude that dependence on long duration storage increases when the system is optimized over more years. In a survey of storage requirement and storage costs studies (Schmidt et al., 2019) conclude that costs are not commonly defined; there is not a common treatment of performance parameters, such as capacity degradation; only a small number of storage applications are included; industry reports lack transparency on costing methodologies while industry reports and academic studies fail to adjust for future cost changes. (Beuse et al., 2020) conclude that storage cost estimates lack meaningful models to assess alternative market and technology scenarios.

The nature and extent of inclusion of substitutes and complements to storage also greatly affect model results. This includes, amongst others: the treatment of interconnection (Cebulla et al., 2017),(Newbery, 2018) sector-coupling (heat, hydrogen, mobility "power to x") (Zerrahn et al., 2018); VRE curtailment (see in particular (Schill & Zerrahn, 2018) versus (Sinn, 2017); demand flexibility (Denholm et al., 2010), (Schill & Zerrahn, 2018); the extent of electric vehicle integration (Newbery, 2018); the relative mix of wind and solar (Cebulla et al., 2018); and building energy efficiency (Houssainy & Livingood, 2021).

With respect to modelling techniques (Guerra et al., 2020) identify limitations in temporal representations commonly applied to models, for example time slices or representative days for capacity planning models, or the usage of short optimization windows in production cost models — typically 48 hours. (Sioshansi et al., 2022) reiterates this concern and in their wider review of resource adequacy, capacity expansion, strategic behaviour, production cost and price taking models they conclude that there is not a 'one-size-fits-all' approach to modelling energy storage. They suggest that the value of modelling approaches differ depending upon the technology and decision maker's perspective.

There is a smaller literature focussed on the economics of storage in power systems with high VRE. Various metrics are used to measure the economics of storage. Though not easily comparable, the various studies suggest long duration storage cost estimates over a reasonably wide range. (Ziegler et al., 2019b) considered wind/solar and storage at the individual facility level and assessed cost and duration requirements to produce a consistent 'baseload' power output. They concluded that a combination of power and energy capacity costs of US$1,000 per kW and US$20 per kWh and a duration of 100 h is sufficient to enable steady power output 100% of the time (see also (Ziegler et al., 2019a)).

(Guerra et al., 2020) look far ahead (they specify 2050–2070 timeframe) in the Western United States assuming 83.4% renewable electricity (61% VRE) to estimate energy costs for storage discharge durations of 1 week, 2 weeks and 1 month contingent on round-trip efficiency and asset life and power-related costs. They conclude, inter alia, that a storage technology with a power-related cost of US$500 per kW would be cost-effective in the 2050–2070 timeframe for discharge durations of 1 week, 2 weeks, and 1 month if energy-related cost is less than US$6.9 per kWh, US$3.5 per kWh and US$1.6 per kWh respectively.

(Albertus et al., 2020) suggest storage costs must be reduced to $3/kWh (for a duration of 100 h), $7/kWh (for a duration of 50 h), or 40 $/kWh (for a duration of 10 h) to be profitable in the United States. (Sepulveda et al., 2021) estimate storage costs needed to be competitive with nuclear, gas with CCS or blue hydrogen in Texas and New England. They conclude that for storage to displace nuclear (for the least competitive firm technology) an energy storage capacity cost of ≤US$10 per kWh is required. Energy capacity costs of ≤US$1 per kWh as well as high efficiencies (low round trip losses) are required to displace firm technologies characterised by lower fixed costs and higher variable costs, for example, natural gas with CCS and hydrogen combustion turbines.

(Houssainy & Livingood, 2021) consider fully renewable electrical systems in five separate regions of the United States regarding the scope to reduce storage requirements through building energy efficiency, load flexibility and optimal overgeneration. They suggest storage energy capacity costs of $43 to $73/kWh in three of the five regions, and even higher than this in the remaining two regions are needed. They also suggest that a combination of optimally mixed renewable portfolios, oversized generation capacities, and building energy efficiency investments can eliminate the need for long-duration energy storage in three of the five regions.

4. Methodology

The objective of this analysis is to understand the relationship between Net Load (NL), variable renewable electricity production and storage. VRE is assumed to be dispatched whenever it is available, and surplus VRE that is not consumed is stored until the storage is full. If the storage is not depleted, it is discharged to meet demand if there is not sufficient VRE. Any amount of demand that is not met by VRE or electricity produced from storage, is assumed to be met by dispatchable generation.

The analysis also assumes, for the cases of 5 GWh or less of storage, that the duration of storage (the number of hours at which peak charge or discharge rates can be sustained) is not less than two hours (5GWh divided by 2 hours is 2.5 GW per hour and hourly peak NL almost never exceeds 2.5). This assumption is made to eliminate charge and discharge rate constraints. It also reflects the observed reality in Australia, as elsewhere, of the predominance of shorter duration storage in early storage development[xi].

For simplicity there are assumed to be no constraints on the minimum storage level and round-trip losses are assumed to be zero. No constraints on the transmission and distribution of VRE are assumed, so that any VRE surplus is assumed to be stored rather than curtailed (unless storage is full in which case it is curtailed or assumed to be exported at an assumed price of $0/MWh – consistent with the observation of average prices when SA exports).

Formally, the logic is as follows:

For t = 1 to 8,760

$If\ NL_t \geq 0\ then,$

$\quad if\ Bat_{t-1} > 0,$

$$NL_{t,a} = NL_t + \text{maximum}\left(NL_{t-1} - Bat_{t-1}, 0\right)$$

$\quad otherwise$

$$NL_{t,a} = NL_t$$

$If\ NL_t < 0\ then,$

$\quad if\ \ Bat_{t-1} > 0,$

$$NL_{t,a} = NL_t + \text{minimum}\left(-NL_t, Bat_{i,0} - Bat_{i,t-1}\right)$$

$\quad otherwise$

$$NL_{t,a} = minimum(0, Bat_{i,0} + NL_t)$$

$$Bat_t = NL_{t,a} - NL_t + Bat_{t-1}$$

where

- $NL_{t,a}$ is the calculated Net Load in hour (t), after the effect of storage charge or discharge as the case may be

- $NL_t = \sum_{k=1}^{12} [OD_{k,t} + (\alpha - 1) * RTS_{k,t} - \alpha * (LSS_{k,t} + Wind_{k,t})]/1000$, is the Net Load (measured in Giga-Watt hours (GWh) in each five minute trading interval, k, for each hour, t, from 00h00 on 31 August 2022 until 00h00 on 31 August 2023

- $OD_{k,t}, RTS_{k,t}, LSS_{k,t}, Wind_{k,t}$ is the Operating Demand, Rooftop (small scale) Solar, Large Scale Solar and Wind for each generating units in each five minute trading period, k, for each hour, t, from 00h00 on 31 August 2022 until 00h00 on 31 August 2023 in the South Australia region of the National Electricity Market. These data originate in NEMWeb (www.aemo.com.au/nemweb) and have been obtained from www.v-nem.org.

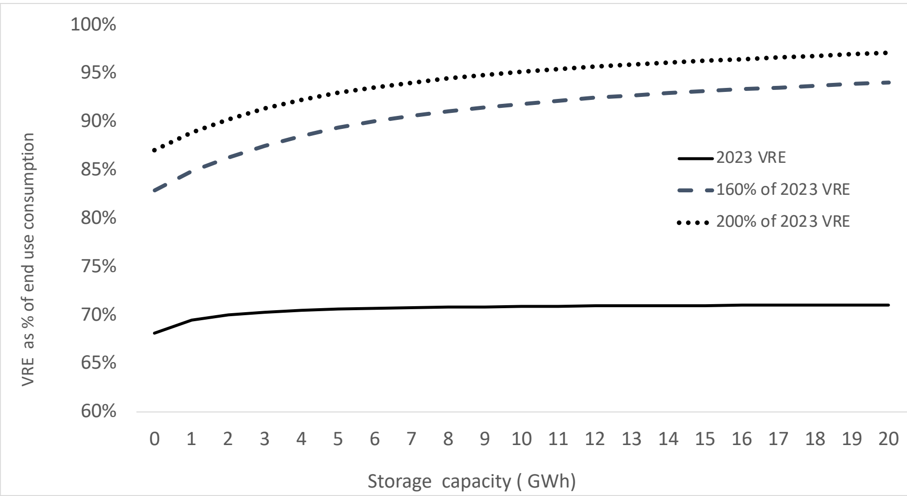
- $Bat_{i,0}$ is a user-specified quantity of storage specified in Giga-Watt-hours (GWh)

- α can take the value of 1 or 1.6.

The analysis has two VRE assumptions: the status quo to 31 August 2023 “2023 VRE”, ($\alpha = 1$) and an expanded VRE case equal to 160% of 2023 VRE, in which wind farms, rooftop solar and large scale solar are all expanded by 60% of their 2023 level ($\alpha = 1.6$).

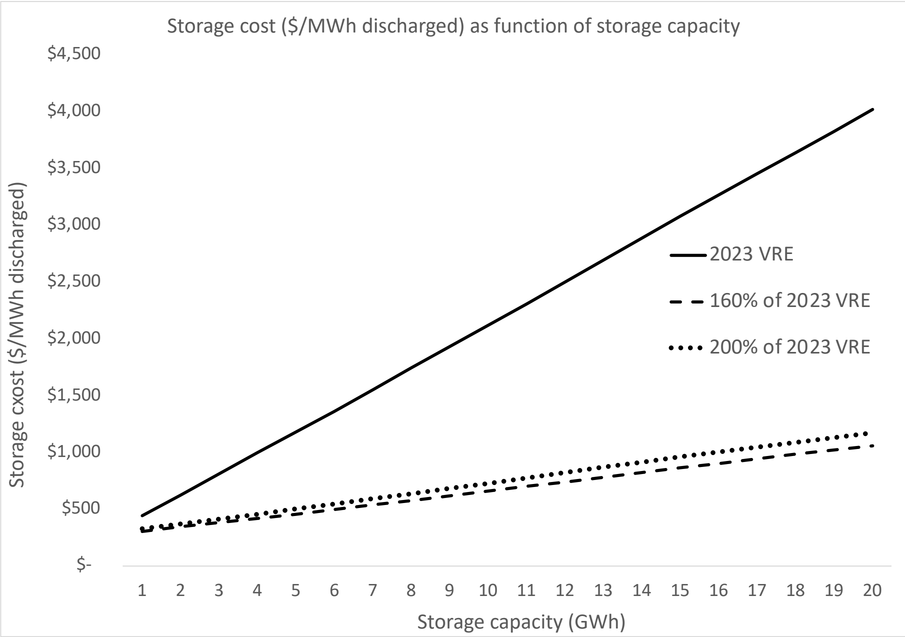
This 160% assumption followed a heuristic search. Noting that this study is not seeking to optimise, this assumption nonetheless bears justification: why not assume substantially more or less than this? The objective of this analysis to understand the relationship between storage and VRE penetration and the consequential costs. Figure 9 presents the results of the analysis, using the battery operation logic described above. It shows that without expanding VRE adding more than 1 GWh of storage makes little difference to VRE penetration. This is because there is not enough VRE surplus to store and subsequently reproduce to displace fossil fuel generation. By comparison, the chart shows that adding a further 60% VRE makes storage much more productive in displacing fossil fuels, particularly for the first 5 GWh of storage (the relationship is concave and quickly asymptotes). Doubling 2023 VRE shows the same relationship to storage as 160% of 2023 VRE, but it is clear from the chart that the additional 40% VRE only makes a small (circa 5%) difference to VRE penetration (most of the additional VRE will be curtailed) and that the VRE penetration gap between 160% and 200% narrows with the addition of storage.

Figure 9. Renewable electricity as percent of end use consumption for different assumptions of storage capacity and VRE expansion



Might it nonetheless be the case that the additional cost of 40% more VRE (i.e. the difference between 200% and 160% of 2023 VRE) is offset by the need for less storage to deliver the same decarbonisation? This was tested by establishing the annual storage cost for the 2023 VRE, 160% of 2023 VRE and 200% of 2023 VRE assumptions for storage capacity ranging between 0 and 20 GWh, as shown in Figure 10. As is clear from this chart, the average storage cost in fact increases for the 200% of 2023 VRE cases because it is used less intensively than for the 160% of 2023 VRE cases. For these reasons we have rejected the inclusion of the 200% VRE assumption.

Figure 10. Annual storage cost ($/MWh discharged) as a function of storage capacity and VRE assumptions.

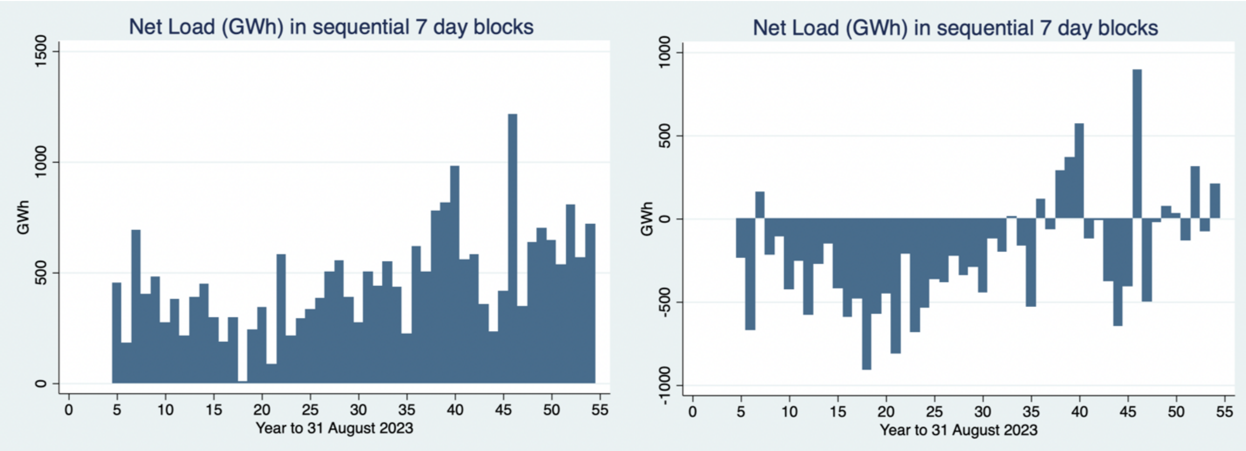


Finally, the analysis considers four storage cases: 1 GWh, 5 GWh, 20 GWh and 200 GWh. The 1 GWh case is selected to show the effect, assuming no VRE expansion, of relatively small storage expansion (1GWh is twice the 0.5 GWh already installed). However, it is clear from Figure 9 that very much more than 1 GWh will be needed to meaningfully displace fossil fuel generation. 5 GWh is chosen from the observation in Figure 9 of the approximate threshold at which marginal increases in VRE penetration occur at an appreciable lower rate. 20 GWh and 200 GWh were chosen as multiples of 4 of 40 on the base of 5 GWh, reflecting the strongly diminishing returns to scale evident in Figure 9 and as expected *apriori* and from observation in the literature. As it has turned out, as shown in the next section these storage increments deliver approximately equal increases in VRE penetration.

5. Results

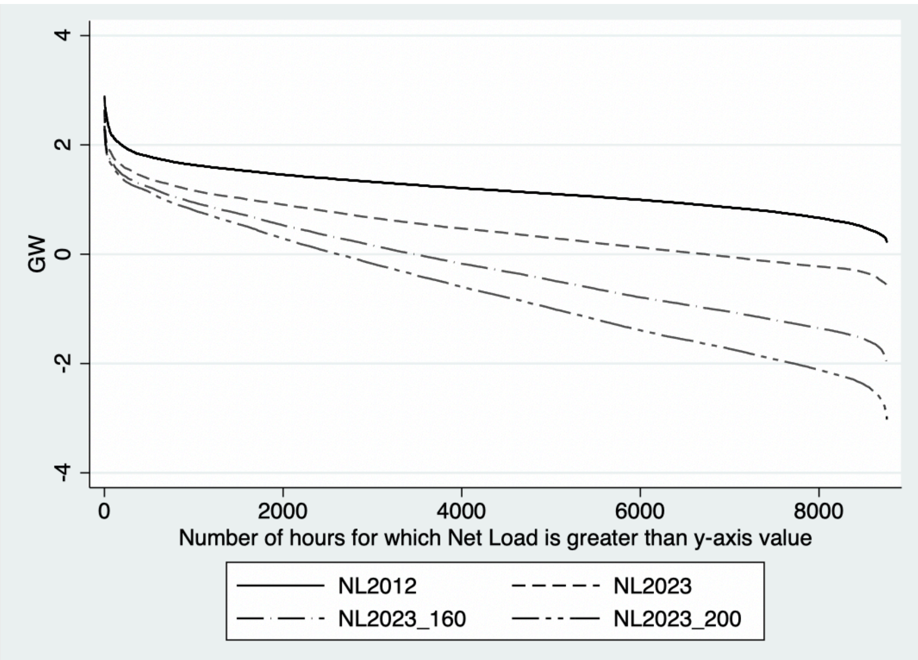
Figure 11a and 11b show the Net Load in sequential 7 day blocks for the period to 31 August 2023 (“2023 VRE”) and then assuming 160% of the 2023 variable renewable electricity “160% of 2023 VRE”. Comparing Figure 11b with Figure 11a it is clear that, as expected, the expansion of VRE to 160% of its 2023 value results in many more 7-day blocks of negative NL. Appendix A, B and C presents charts of Operating Demand, Net Load and Dispatchable Generation Requirement (i.e. the positive values of Net Load) for sequential 7-day, 8 hour and 1 hour blocks), comparing the 2023 VRE and 160% of 2023 VRE cases.

Figure 11a and 11b. Net Load in sequential 7 day blocks assuming 2023 VRE (9a – left hand), and 160% of 2023 VRE (9b – right hand).



Duration curves of the hourly Net Load over the year to 31 August 2023 show the effect of increasing VRE. Figure 12 shows duration curves of the hourly Net Load in 2012, 2023 (year to 31 August 2023), and assuming 160% of 2023 VRE and 200% of 2023 VRE. In 2012, the minimum hourly average NL was 223 MW, by 2023 (year to 31 August 2023) VRE as a proportion of SA Operating Demand had more than doubled and so the minimum hourly average NL had fallen to -599MW and NL was negative for 2,029 (out of 8760) hours over this period. If VRE expands to 160% of its 2023 level, the hourly average minimum gets to -2,013 MW (and NL will be negative for 5,294 hours in the year). To reiterate, this assumes no VRE curtailment. VRE curtailment is unlikely to affect the number of hours of negative NL but will affect the extent to which VRE exceeds demand, when it does.

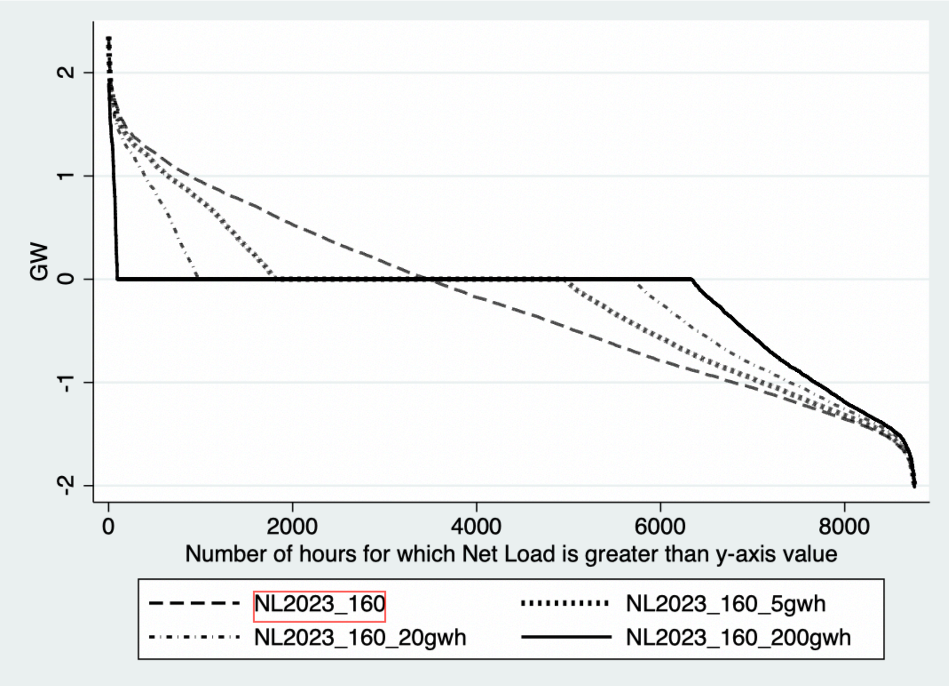
Figure 12. Hourly average Net Load duration curves for 2012, 2023, 160% of 2023VRE and 200% of 2023VRE



Turning now to the effect of storage on Net Load based on the logic described in the previous section, Figure 13 shows that in the case of 200 GWh storage this is sufficient to almost eliminate the need for dispatchable generation – there are just 94 hours (101 GWh) with positive NL (i.e. the need for dispatchable generation to meet demand). With 20 GWh the need for dispatchable generation rises to 974 hours (835 GWh) and with 5 GWh of storage it rises to 1814 hours (1489 GWh).

Comparing the areas bounded by the X-axis and the relevant NL curves, there is a rapidly diminishing return to storage: the first 5 GWh reduces the demand for dispatchable generation by about as much as the next 15 GWh. Likewise, those 15 GWh of storage reduce the demand for dispatchable generation by about as much as the next 180 GWh.

Figure 13. Hourly average Net Load duration curves assuming 160% of 2023VRE with 0, 5, 20, 200 GWh of storage



How can there be such a remarkable decline in the yield from storage? (Cebulla et al., 2017) explain it in general terms as attributable to greater need for storage to meet seasonal demands. This times series analysis provides a detailed explanation in the case of South Australia. Table 1 presents monthly data of Surplus VRE (total NL for all hours in the month when NL>0), Dispatchable Generation Requirement (before storage) (total NL for all hours in the month when NL>0) and then the monthly values of the charge, discharge and DGR after storage for the 5, 20 and 200 GWh storage cases. The data show seasonality in positive DGR (the average for the three summer months is about a third of the average for the winter months). One month – May (late autumn) – however sticks out as having appreciably higher DGR than other months. This is consistent with the information presented in Figure 2.

The results in the table show that 5 GWh storage is sufficient to reduce DGR to small amounts (15-47 GWh) but substantial winter DGR remains (168-244 GWh). Adding a further 15 GWh of storage reduces DGR to zero or close to zero from late spring through to early autumn, but again reasonable DGR still remains in the late autumn and winter period (112-277 GWh). Adding another 180 GWh of storage reduces DGR to zero in all months except May (101 GWh).

Comparing the charge and discharge numbers for each level of storage reveals small differences for the 5 GWh storage, slightly bigger differences for the 20 GWh storage, but much bigger differences for the 200 GWh case particularly in May where clear inter-month shifts are visible (a net 106 GWh was discharged). Only with 200 GWh of storage capacity is there sufficient storage to carry surpluses from spring and summer through to the following late autumn and winter, but even so not enough for the month of May.

Table 1. Monthly measurement of Surplus VRE (when VRE exceeds demand) before storage, Dispatchable Generation Requirement (DGR), storage charge, storage discharge and DGR after storage assuming 160% of 2023 VRE (GWh)

Month	Surplus VRE (GWh)	Dispatchable Generation Requirement (DGR) before storage	5 GWh storage			20 GWh storage			200 GWh storage		
			Charge	Dis-charge	DGR after storag	Charge	Dis-charge	DGR after storage	Charge	Dis-charge	DGR after storage
Sept	355	202	84	(84)	119	142	(138)	64	264	(202)	-
October	397	166	88	(86)	80	161	(155)	11	204	(166)	-
November	362	104	79	(79)	25	104	(104)	-	104	(104)	-
December	532	78	61	(61)	17	78	(78)	-	78	(78)	-
January	454	96	59	(59)	37	85	(93)	2	85	(96)	-
February	375	116	69	(69)	47	118	(109)	7	127	(116)	-
March	320	190	107	(110)	80	162	(180)	10	162	(190)	-
April	325	188	86	(88)	100	142	(144)	44	175	(188)	-
May	194	402	68	(63)	339	139	(125)	277	194	(301)	101
June	391	209	37	(42)	168	83	(97)	112	259	(209)	-
July	327	315	72	(72)	244	164	(153)	163	327	(315)	-
August	249	325	88	(88)	237	175	(174)	149	249	(323)	-
TOTAL	**4,281**	**2,392**	**897**	**(900)**	**1,492**	**1,553**	**(1,551)**	**838**	**2,228**	**(2,288)**	**101**

The corollary of the declining yield from storage is much lower capacity factors for the larger batteries. Whereas the 5 GWh battery has an average annual (discharge) capacity factor of 2.1%, the 20 GWh battery's capacity factors was 0.9% and the 200 GWh just 0.006%.

To get a sense of the meaning of these capacity factors, storage that is fully discharged once a day (once every 24 hours) every day for a year would have an (annual) capacity factor of 1/24 = 4.2%. Noting the 2.1% capacity for 5 GWh storage, this capacity factor can therefore be equivalent to discharging around half its capacity once each day (i.e. 2.1%/4.2%), on average. By comparison the 200 GWh storage has an annual capacity factor of 0.006% (101GWh/(8760 hours*200 GWh)) and so can be considered to be discharging just 0.001% of its capacity per day on average over a year. Yet, as Table 1 shows, even such a large amount of storage is still not able to fully meet dispatchable demand in all months in the year assuming aggregate renewable generation capacity that is 160 % larger than now which delivers an aggregate surplus (before storage) of 4.3 TWh or 30% of total end-use demand.

It should be stressed that the storage charge/discharge algorithm used here ignores round-trip losses and network constraints. It also assumes that batteries are charged whenever there is surplus renewable generation, until they are full. We also assume away possible power system constraints (voltage, system strength) that will affect the ability to move renewable electricity on the network. In the next section we discuss whether these (and other factors) might suggest this analysis is likely to under or over-estimate the effectiveness of storage in decarbonising electricity supply in SA.

6. Discussion

Australia has established renewable electricity targets for 2030 (82% of generation from renewable electricity) that will require a greater proportion of VRE in its electricity mix than in any other country in the G20, OECD or Asia Pacific[xii]. Within Australia, South Australia is leading other regions with a penetration of variable renewable electricity (76%) that is twice as high as the next highest jurisdiction in Australia. South Australia also has excellent wind resources with relatively small seasonal variation. Solar insolation has winter yields around third those in summer (rooftop solar) and half (solar farms) which is a level of seasonal variability that is lower than in most other rich countries. It may be expected therefore that South Australia should be able to achieve high levels of variable renewable electricity consumption with relatively less storage than in regions that do not share its access to high quality and relatively consistent VRE.

The analysis in this study, consistent with the broad direction of the literature is that storage yield declines sharply. In this case the first 5 GWh of storage displaces substantially more dispatchable generation than the next 15 GWh which in turn displaces about as much as the next 180 GWh of storage. With these results it is possible to proceed to answer our second set of questions: will it be affordable and economically sensible to build that additional storage?

Costing

Contemporary estimates of current and future storage and renewable electricity costs supplied by Australia's National Science Agency (see (Graham et al., 2023)) are used. The calculation here counts the net cost reduction from displacing expensive hydrocarbons (in SA, mainly gas generation) with relatively cheaper renewable electricity; the additional cost of the storage and the cost of the unused (curtailed) renewable electricity production[xiii].

Table 2 below uses official estimates of technology costs[xiv] to estimate the net additional annual cost, relative to the 2023 Baseline, of combinations of VRE expansion (160% of 2023 VRE) and storage expansion (1, 5, 20 and 200 GWh).

Table 2. Annual cost of additional VRE and storage relative to 2023 baseline

VRE assumption	Baseline (2023 VRE)		160% of 2023 VRE				
Storage assumption	No additional storage	+1 GWh	No additional storage	+1 GWh	+5 GWh	+ 20 GWh	+ 200 GWh
Additional annual cost of curtailed VRE ($m)		$ (12)	$ 255	$ 237	$ 196	$ 153	$ 109
Additional annual cost of storage ($m)		$ 60		$ 60	$ 298	$ 889	$ 8,586
Net annual cost reduction from displacement of gas generation ($m)		$ (17)	$ (192)	$ (217)	$ (276)	$ (337)	$ (405)
Net additional annual cost relative to Baseline ($m)		$ 30	$ 62	$ 79	$ 218	$ 705	$ 8,289
VRE as percentage of aggregate end-use demand	68%	69%	83%	85%	89%	94%	99%
Implied carbon price ($/tonne $CO_{2\text{-}e}$)		$ 320	$ 60	$ 38	$ 147	$ 389	$ 3,803

Table 2 shows for the Baseline in the second column that in 2023 (year to 31 August), 68% of SA's end-use demand was met from renewable electricity. The third column shows that adding 1 GWh of storage without expanding VRE, will increase VRE as a percentage of end-use demand by just 1%, at an implied carbon price of $320 per tonne $CO_{2\text{-}e}$. This reflects the combination of the small amount of storage capacity and the small amount of negative NL (surplus VRE) currently available the battery is under-used for want of VRE to charge it.

Expanding VRE to 160% of the 2023 level (fourth column) and not adding any additional storage has a small additional cost of $62m per year (the additional annual costs of the VRE is largely offset by the reduction in costs of producing electricity from fossil fuels) and will result in 83% of SA's end-use electricity being sourced from renewable generation. The implicit carbon price of expanding SA's VRE to 83% from its current 68% is estimated to be $60 per tonne of emissions abated from the fossil fuel generation.

The fifth column shows that adding 1 GWh of storage adds cost in storage but this is largely offset by reduced curtailment and the displacement of gas generation. Although 1 GWh of storage only increases VRE penetration by 2%, this is enough to reduce the implied abatement cost relative the case of only expanding VRE by 60% and not adding any storage.

The sixth column shows that adding 5 GWh of storage will increase the proportion of end-use demand met by renewables to 89% (6% more than expanding VRE to 160% of 2023 levels but with no storage), but this will add $298m per year of additional (storage) cost partial offset by less curtailment, and so the net cost has an implicit carbon abatement cost of $147/tonne CO_2.

Adding the next 15 GWh (seventh column) raises storage costs significantly so that the implicit carbon abatement cost rises to $389/ tonne $CO_{2\text{-}e}$. The implicit carbon price does not however rise in proportion to the additional storage because, with sufficient power capacity to ensure no charging or discharge rate constraints, we have assumed that much cheaper 8 hour storage is developed once the first 5 GWh is developed.

Adding the next 180 GWh (the eighth column) by expanding storage to 200 GWh, gets to 99% VRE share of end-user consumption at a roughly 10-fold increase in storage costs and implicit abatement cost relative to the 20 GWh case. The implicit abatement cost ($3,803 per tonne CO_2) is around 10 times the mid-point of the AUD208-AUD567 per tonne CO_2 in (Environmental Protection Agency (U.S.), 2022).

What about affordability? Expanding VRE in SA by 60% and adding 5 GWh of storage (0.04% of end user annual electricity consumption or about 10 times more storage than is already operational in SA) will add $218m per year to wholesale electricity costs (16% of the spot market cost of electricity in SA in the year to 31 August 2023). Adding a further 15 GWh of storage will have a total annual cost of $705m (so adding 53% to the spot market cost of electricity in SA in the year to 31 August 2023). Such a large increase is likely to require substantial policy support. Getting close to full decarbonisation, through VRE expansion and storage, will evidently require very large amounts of storage (400 times more than is already operational in SA or 0.3% of end-use annual consumption). This will raise the wholesale cost of electricity to be six times higher than now and so clearly not viable for consumers in the absence of very substantial policy support from taxpayers.

If storage costs decline around 20-fold from their currently projected estimates, it might be expected that storage will be able to displace fossil dispatchable generation at an implicit carbon cost below the Social Cost of Carbon.

Limitations

These estimates may be suggested to have overstated or understated storage requirements and/or its cost. It might be suggested the estimate storage requirement is overstated if it was assumed that demand becomes more elastic to VRE production, or storage in vehicles becomes abundant and available to grid or low/zero emission dispatchable generation became competitive. But this study seeks to use consensus (or at least officially endorsed) assumptions on the cheapest available storage. If better alternatives arise the challenges identified may be better met pursuing those alternatives. This is addressed in the concluding section.

It might also be suggested that the storage requirement is overstated on the basis that the study period (to 31 August) was more demanding than previous years, for example the extraordinarily high Net Load in May as shown in Figure 2. On the other hand, the very high Net Load in May was followed by the extraordinarily low Net Load in June. Figure 2 shows appreciably lower NL in most month than in previous suggesting a lower storage requirement than if earlier data was used. This is to be expected considering the growth in VRE. Scaling up previous years' NL data rather than the using the latest data but this would invite assumption errors in failing to account for the latest information on VRE expansion. On balance, we suggest the chosen period is plausible and unlikely to be biased to the extent that the central conclusion would change.

It may be suggested that assuming unchanged contribution from interconnection fails to account for interconnector expansion currently underway. On the other hand, the neighbouring states are themselves committed to rapid closure of their coal generation and thus the technology providing dispatchable support in SA (coal generation in Victoria) that is currently reducing the need for storage in SA is not likely to be able to continue to provide that service to SA. Further interconnection might reduce SA's need for its own storage and VRE expansion but neither VRE nor storage is more cheaply produced by SA's neighbours than in SA. In addition, the high correlation of VRE in SA with VRE production by its neighbours suggests interconnection is unlikely to present a cheaper option for decarbonisation in SA or its neighbours.

It might be suggested that the estimates in this study are understated in that they ignore round-trip losses and assume that storage is operated in such a way as to maximise its contribution to the usage of renewable electricity (by charging whenever there is a VRE surplus and discharging whenever these is a VRE shortfall relative to dispatchable (fossil) generation. The assumption of zero round trip losses will indeed understate the storage requirement, but it is not certain what affect this will have. For the larger storage cases (20 GWh and 200 GWh) the assumption of round-trip losses is not likely to be significant since, for the vast bulk of the year in both cases, a 10-15% reduction in storage capacity would not have a large effect on the greater use of renewable electricity, as evident in the results in Figure 13 and Table 1.

The assumption that storage is operated in such a way as to maximise the consumption of renewable electricity is support by observation of the data: as discussed earlier, in the year to 31 August 2023 the weighted average price when NL negative was -$18/MWh, suggesting powerful incentives to charge batteries when NL is negative. On the other hand, it was also noted that for 8,575 of the 24,527 five-minute intervals when NL was negative, the spot price was positive and the average price in these times was $17/MWh. If this pattern persists in future, then this undermines the assumption that storage will be operated in practice so as maximise the use of VRE, suggesting that this analysis is likely to understate the storage requirement.

Finally, the assumption that storage is operated in such a way as to maximise the consumption of renewable electricity rests on the premise that in future transmission or distribution constraints do not meaningfully affect storage operation. This is reasonable considering the powerful incentives on storage to locate at points in the (intra-regional) transmission and distribution networks where its operation is not likely to be constrained. Long distance transmission augmentation is unnecessary (indeed it is likely to be avoided) through the installation of storage as assumed here. The nature of chemical storage (small footprint, small ancillary infrastructure requirement) means that it can be expected to be able to respond effectively to such incentive.

7. Conclusions and policy implications

VRE already dominates supply in SA, and both the SA Government and the Australian Government are seeking further rapid decarbonisation. The development of storage will be essential if this to be achieved in the absence of low or zero emission dispatchable generation alternatives. But to what extent will storage displace dispatchable generation, and will it be viable for consumers, and economically sensible to build that additional storage?

In summary, this time series analysis suggests that raising VRE penetration in SA to around 90% of end use consumption through VRE expansion and storage will be viable for consumers and economically sensible. However, the analysis also finds that the declining yield from storage suggests that with current technologies, displacement of the last 10% of fossil fuel by storing and later using renewable electricity, will be achieved at implied carbon abatement costs far above contemporary estimates of the Social Cost of Carbon. It will also place such a large burden on consumers (getting to 99% VRE penetration will add annual wholesale cost by an equal to six times 2023 spot market cost) that such outcome is inconceivable without large amounts of support from taxpayers. This is because very large amounts of storage are needed to come close to fully decarbonising supply, but this storage is very seldomly used.

The conclusions are specific to SA, but of wider relevance in Australia and abroad. SA has excellent VRE resources with relatively low seasonal variation by the standards of other developed economies. This is likely to reduce the demand for storage in SA relative to that in other countries/regions. On the other hand, SA has inconsequential dispatchable renewable energy (hydro, geothermal or biomass) or emission free production (nuclear) and this will increase the requirement for storage in SA relative to countries/region with access to such resources. The time-series method used here provides a transparent assessment approach that can be adapted to account for local conditions.

Several policy implications might be anticipated. First relatively small storage expansion up to 10 times existing levels (up to 0.04% of end user annual consumption) will deliver VRE penetration of 90% (in tandem with an expansion of VRE capacity by 60%). Such outcome should therefore be affordable for consumers and economically sensible and is not likely to require inordinate amounts of policy support[xv].

Secondly, it does not seem to be sensible to commit to decarbonisation through storage for the last 10% of consumption unless it is expected that storage becomes very much cheaper than it is now (i.e. a 20-fold reduction on the currently expected cheapest long duration technology). Since such a steep decline is not currently foreseeable, policy might be expected to prioritise decarbonisation in other parts of the economy before pursuing the final 10 % through storage. Actively pursuing other (non-storage) avenues for decarbonisation of electricity supply will also be important. This includes encouraging a stronger temporal association between electricity demand and VRE supply, pursuing low or zero carbon dispatchable generation and harnessing storage in electric vehicles for use on the electrical grid.

Considering the (rapid) rate of technology change, keeping storage and zero emission dispatchable generation options open as far as this is reasonably possible is likely to be valuable.

Appendix A. Operating demand

Figure A.1 Operating Demand (2023 VRE) (a) and (160% of 2023 VRE) (b) in sequential 7 day blocks, year from 1 September 2022

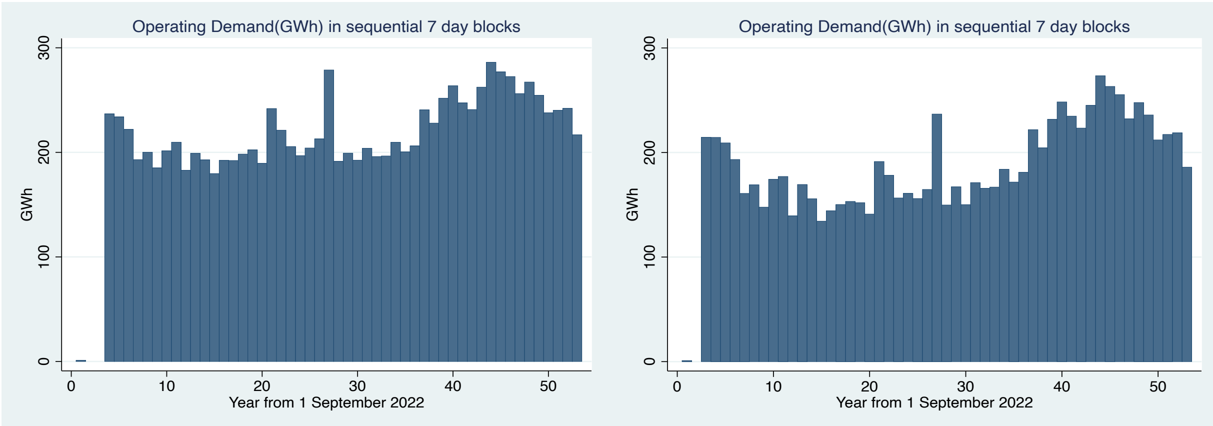


Figure A.2 Operating Demand (2023 VRE) (a) and (160% of 2023 VRE) (b) in sequential 8 hour blocks, year from 1 September 2022

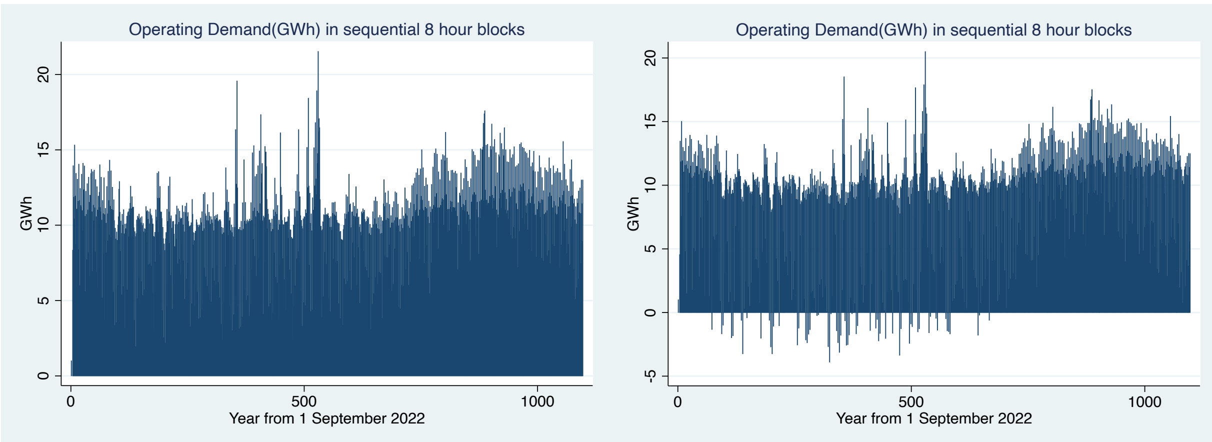
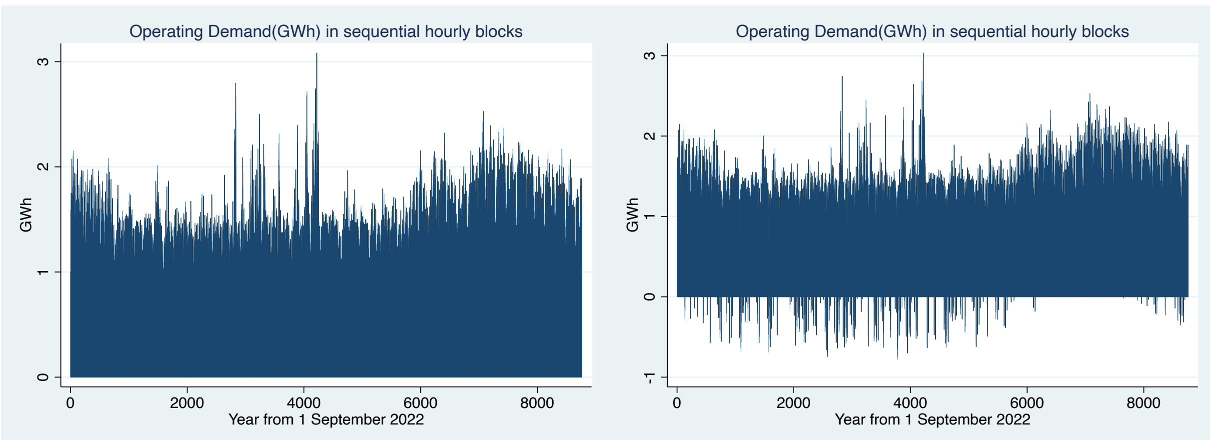


Figure A.3 Operating Demand (2023 VRE) (Figure A1(a) and (160% of 2023 VRE) (Figure A1(b)) in sequential hourly blocks, year from 1 September 2022



Appendix B. Net Load

Figure B.1 Net Load (2023 VRE) (a) and (160% of 2023 VRE) (b) in sequential 7 day blocks, year from 1 September 2022

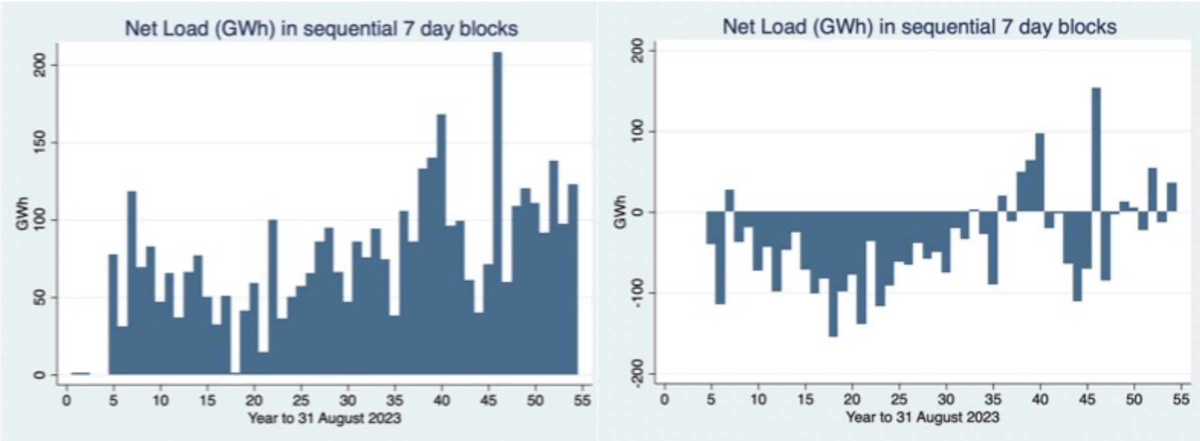


Figure B.2 Net Load (2023 VRE) (a) and (160% of 2023 VRE) (b) in sequential 8 hour blocks, year from 1 September 2022

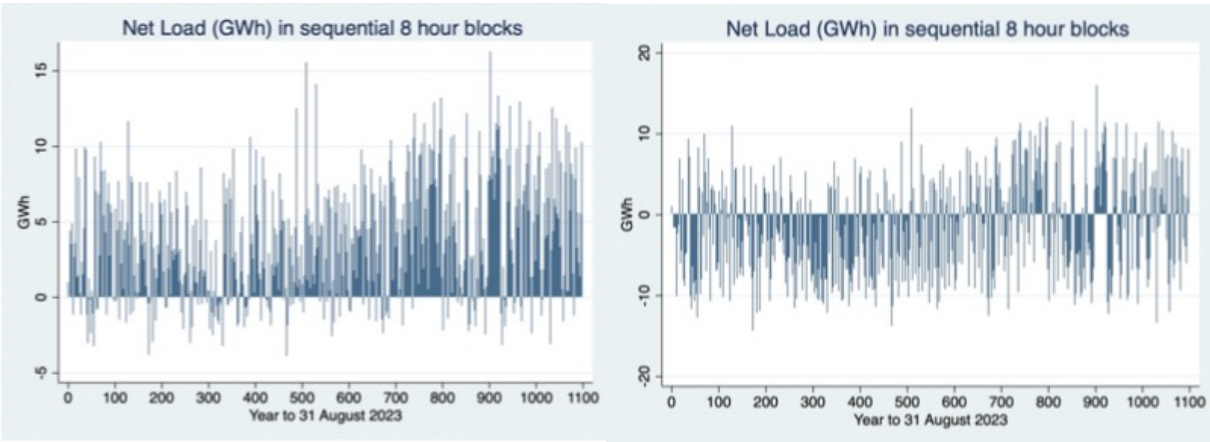
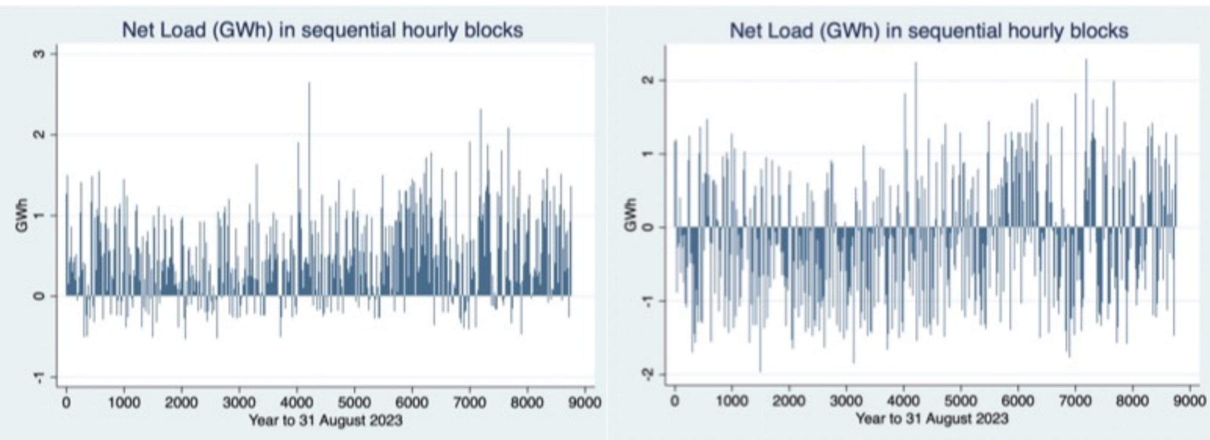


Figure B.3 Net Load (2023 VRE) (a) and (160% of 2023 VRE) (b) in sequential hourly blocks, year from 1 September 2022



Appendix C. Dispatchable Generation Requirement (DGR)

Figure C.1 DGR (2023 VRE) (a) and (160% of 2023 VRE) (b) in sequential 7 day blocks, year from 1 September 2022

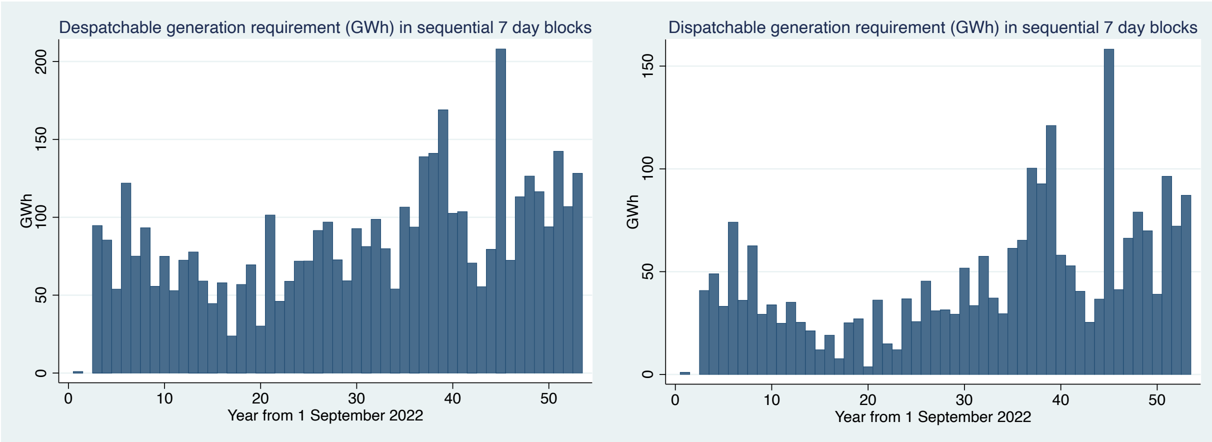


Figure C.2 DGR (2023 VRE) (a) and (160% of 2023 VRE) (b) in sequential 8 hour blocks, year from 1 September 2022

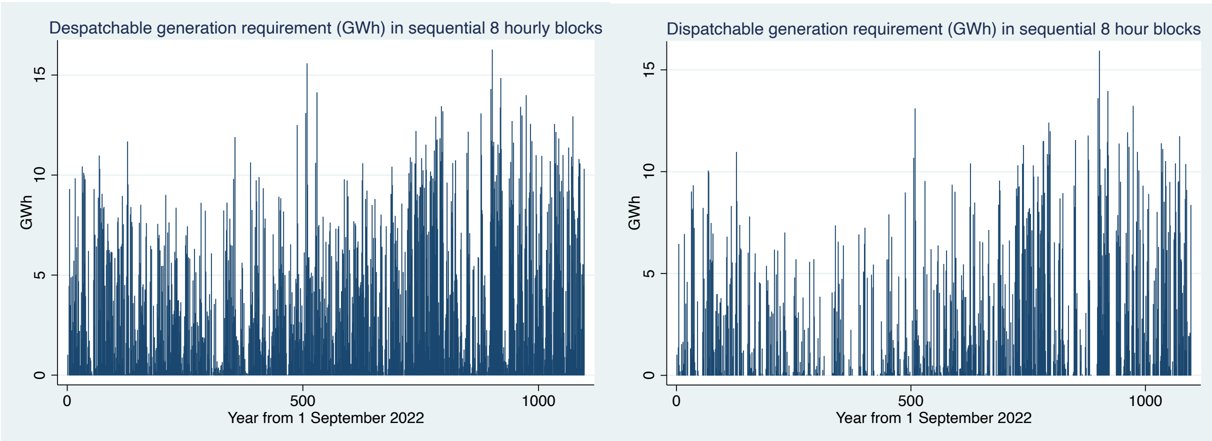
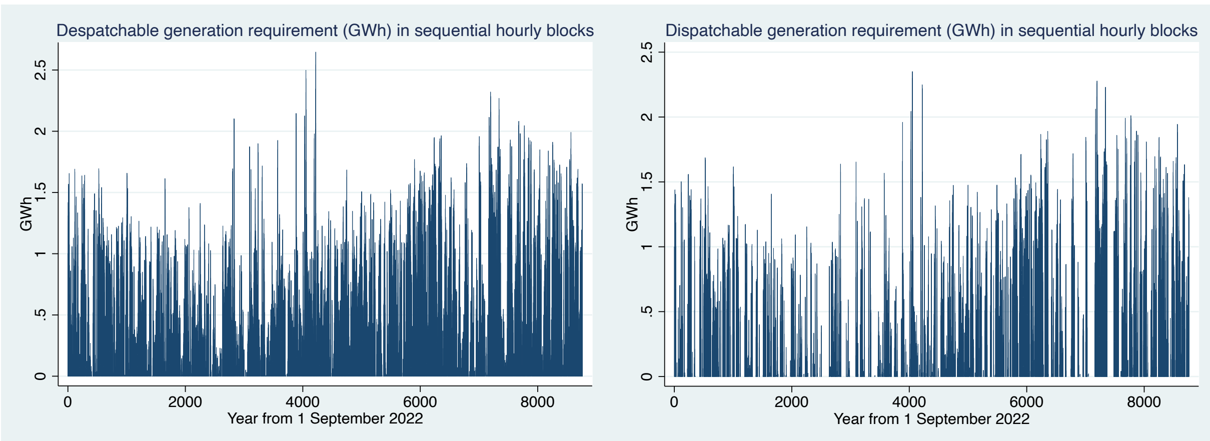


Figure C.3 DGR (2023 VRE) (a) and (160% of 2023 VRE) (b) in sequential hourly blocks, year from 1 September 2022



Endnotes

[i] https://www.v-nem.org
[ii] https://yearbook.enerdata.net/renewables/wind-solar-share-electricity-production.html
[iii] https://www.energymining.sa.gov.au/industry/modern-energy/leading-the-green-economy#:~:text=Renewable%20energy,-South%20Australia%20is&text=South%20Australia's%20aspiration%20is%20to,on%20180%20days%20(49%25)
[iv] https://www.dcceew.gov.au/energy/renewable/capacity-investment-scheme#:~:text=The%20Capacity%20Investment%20Scheme%20(CIS,capacity%2C%20such%20as%20battery%20storage.
[v] https://aemo.com.au/energy-systems/electricity/national-electricity-market-nem/data-nem/market-data-nemweb
[vi] https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/data-nem/operational-demand-data#:~:text=Operational%20Demand%20in%20a%20region,and%20by%20Wholesale%20Demand%20Response.
[vii] The discrepancy between the calculation of the annual net import using 5 minute data and the calculation of the annual net import using hourly data is explained by the hourly data presenting hourly net figures and so hiding the export and import in each five minutes which aggregated over the year will be different than if netted off in each hour and that result extrapolated over the year.
[viii] https://en.wikipedia.org/wiki/Hornsdale_Power_Reserve
[ix] https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-planning-data/generation-information
[x] https://twitter.com/DavidOsmond8/status/1742368228943503808?ref_src=twsrc%5Egoogle%7Ctwcamp%5Eserp%7Ctwgr%5Etweet
[xi] Storage duration (the ratio of the energy capacity measured in GWh to the peak sustainable power charge and discharge capacity measured in GW is relevant in the costing of storage since energy capacity and power capacity costs vary by duration. It is considered in the costing analysis. However, there is no need (and it would be an error) to attempt to segment the supply of storage of different durations in the calculations of storage requirement – which depends on the replacement of dispatchable supply (GWh). As long as the storage capacity has sufficient power capacity to ensure that charge and discharge rate constraints do not bind, there is no need to consider the GW capacity of the storage stock in the evaluation.
[xii] https://ember-climate.org/data/data-tools/global-renewable-power-target-tracker-2030/
[xiii] This electricity might ultimately be exported or find new markets. In the case of exports, these already achieve very low prices and will almost certainly decline as VRE expands. In the case of new markets, it is unrealistic to imagine a price much above zero as long as surpluses remain.
[xiv] VRE costs are based on(Graham et al., 2023) Table B1 (page 64) for 2030. Storage costs for the first 5 GWh assume 2-hour battery costs ($0.51m/MWh) based on CSIRO (2023) Table B4 (page 67) for batteries built in 2030. All storage beyond 5 GWh assumes 8-hour battery cost ($0.366m/MWh) based on (Graham et al., 2023) Table B5 (page 68) for batteries built in 2030. Fossil fuel generation costs are based on efficiency (36%), gas cost ($17/GJ), variable operations and maintenance ($12/MWh) taken from (Graham et al., 2023)Table B8. Capital costs are turned into annual costs assuming 8% discount rate, zero residual, 25-year life for wind and solar and 15 year life for storage.
[xv] It is important to note that the analysis is calculates the net additional cost and so ignores market prices. Since generators receive market prices for their production, not compensation for their costs, it might be the case that policy support will be required particularly to stimulate VRE investment if, as expected, surpluses in VRE result in negative or very low market clearing prices. However, policy support for such reasons might reasonably be considered in welfare economics to constitute a transfer of wealth (in this case from tax payers to consumers unless the government seeks to reclaim the cost of the support from electricity consumers) and so is not counted here.

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