THE GENERATOR OPERATIONS SERIES

Report Six: Unlocking Curtailed Solar Energy on the NEM through Storage

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CONTENTS

Cover image: Moree Solar Farm under a setting sun.

ABBREVIATIONS

AC	Alternating Current
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
ARENA	Australian Renewable Energy Agency
BESS	Battery Energy Storage System
BDU	Bi-Directional Unit
CEFC	Clean Energy Finance Corporation
DC	Direct Current
DHI	Direct Horizontal Irradiance
DNI	Direct Normal Irradiance
DUID	Dispatch Unit Identifier
DUOS	Distribution Use of Service (Charge)
EPC	Engineering, Procurement and Construction
FCAS	Frequency Control Ancillary Services
GHI	Global Horizontal Irradiance
IRP	Integrated Resource Provider
LSS	Large-scale Solar
MLF	Marginal Loss Factor
NEM	National Electricity Market
NSP	Network Service Provider
O&M	Operation and Maintenance
POA	Plane of Array
PR	Performance Ratio
PV	Photovoltaic
UOS	Use of System (Charges)
SRA	Small Resource Aggregator
TNSP	Transmission Network Service Provider
TUOS	Transmission Use of System (Charges)
VRE	Variable Renewable Energy

EXECUTIVE SUMMARY

This study estimates the potential generation, associated revenue and emissions reduction benefits that could be captured by co-locating large-scale battery storage at 44 large-scale solar farms[1] (the studied solar farms) on the National Electricity Market (NEM). The analysis demonstrates several potential benefits flowing from recent amendments to the National Electricity Rules (NER). The amendments introduce the new Integrated Resource Provider (IRP) participant category, determined in December 2021 and coming into effect in June 2024, which remove some of the regulatory and commercial barriers to the colocation of solar, wind and battery storage on the NEM. Levels of under-generation resulting from physical and economic curtailment are calculated at each site over the three years from June 2019 to May 2022. The value of this curtailment is estimated by assuming it can be locally stored by a co-located battery and then sold later each day.

Estimates of available generation were modelled (henceforth referred to as available generation) at each site using satellite data. The timing and magnitude of curtailment was quantified based on the difference between available generation and actual dispatch data from the public NEMWEB database published by the Australian Energy Market Operator (AEMO).

Curtailment occurs when the generation that a solar farm delivers to the grid is less than the amount of generation the equipment was capable of generating at that time, and can occur because the generator:

1. bids in a manner to avoid dispatch during periods of negative pricing (economic curtailment) or
2. is required under the terms of its connection arrangements to limit its generation to maintain the overall power system within acceptable parameters given surrounding network constraints (physical curtailment).

Physical curtailment is split up into network and local limit constraints. Network constraints are identified as periods where a semi-dispatch cap was active outside of negative pricing periods and capped the given farm's output at a level set by the NEM dispatch engine. Local limit constraints are periods where a local limit may have applied to cap the generation of the solar farm outside of the NEM dispatch engine, e.g., where a farm was instructed to switch off some of its inverters for a period of time. Two key sets of limitations need to be recognised with respect to the foregoing analysis.

First, the scope of this study only considers one of the many technical and commercial considerations relevant to the viability of a battery energy storage system (BESS) installation co-located with solar. While there is a significant revenue stream available at several existing solar farms, this needs to be balanced against the risks involved in significant capital outlay given high battery costs, limitations of existing electrical infrastructure onsite to incorporate newer BESS technologies, and the re-opening of existing agreements with AEMO, network service providers (NSPs), asset managers and operations and maintenance contractors, among others. By contrast, the revenue from arbitrage of curtailed energy may be relatively small compared to the potential revenues from a more sophisticated arbitrage strategy allowing charging from the grid and participation in FCAS markets and further ancillary, inertia or capacity markets that may be created in the future. Further, the commercial structure of battery tolling agreements may limit the control existing solar farm owners have over the operation of co-located storage. The findings of this paper may therefore be more useful in demonstrating the size of this untapped energy resource as a whole, as the applicability to individual solar farms depends on a broad range of factors not considered.

Second, the methodology used to quantify and value curtailed energy has several limitations:

- The analysis is based on historical data and does not attempt to forecast future volumes of curtailment or energy price trends.
- The 5-minute regional spot price is used in revenue calculations, ignoring 30-minute settlement prior to October 2021 and marginal loss factors. The latter could significantly reduce the available revenue depending on the farm's location.
- Curtailment attributed to local limits could also be due to inverter outages or other operational issues on site. Despite this type of curtailment being conservatively calculated, it is still possible that some figures have been overestimated.

1 The 44 generators were selected as those which had achieved at least 95 per cent of their maximum capacity prior to December 2020.

- While the estimated volumes of curtailment are likely to be close to the actual curtailment on average, estimates at individual farms may be higher or lower than what actually occurred due to modelling uncertainty, especially due to bias introduced by the use of satellite data over short time periods and bias that may have been introduced by the limited training dataset.
- All curtailed energy was assumed to be captured and sold at the evening peak price, when in reality, the volume of energy captured each day and the price achieved in the sale of this energy will be highly dependent on the capacity and volume of the battery and the specific trading algorithm adopted by the operator.

Nevertheless, the analysis demonstrates that a significant volume of renewable energy is being curtailed at solar farms across the NEM due to negative prices and physical network limitations. The installation of storage assets either co-located with solar farms or at congested points on the network to shift this curtailed energy to be dispatched during the period of peak evening demand represents a $119M per year revenue stream based on the historical generation, price and weather data from June 2019 to May 2022. Several projects at various stages of development are already proceeding in co-locating BESS assets with solar farms, including both retrofits of existing solar farms (e.g., Childers, Susan River and Nevertire Solar Farms [15]) and as part of new solar farm developments (e.g., New England and Wandoan South Solar Farms [16]).

Furthermore, there are several reasons to believe that the size of the potential energy and revenue lost to curtailment is likely to grow. One scenario explored in AEMO's draft 2022 Integrated System Plan states that by 2050 the proportion of variable renewable energy curtailment increases to approximately 20 per cent of total available output [2], so the curtailed energy and revenue figures are conservative relative to the volume of curtailment likely to be seen in the future. The study is also conservative in terms of the assumed price at which arbitraged energy is sold, as it is based on the past three years of price data, giving less weight to the recent surge in electricity prices across the NEM [17].

Thus, the value of curtailed energy at solar farms on the NEM is already significant, but may also increase substantially in the coming years and decades. While commercial and regulatory barriers remain, the introduction of the IRP participant category will improve the likelihood that this untapped energy resource will be captured through the deployment of storage. Unlocking this renewable energy resource would reduce emissions on the NEM by over 600kt CO_2-e per year and could be a critical step in achieving the target of net zero emissions on the NEM by 2050.

See Appendix: Modelling Methodology for more detailed definitions on these metrics.

Ballarat Battery Energy Storage System. Image credit: AusNet Services.

In the three years to May 2022, an average of 13.7 per cent of available energy was curtailed across solar farms in the study. On average, the volume of curtailment in 2019, 2020, 2021 and 2022[2] was 13.1 per cent, 12.3 per cent, 15.4 per cent and 11.0 per cent of available energy, respectively. The total volume of curtailed energy is approximately 980 GWh per year, which is 16 per cent of the total annual generation across the solar farms in the study – or the equivalent of the annual generation of 7 average large-scale solar farms. The lowest level average curtailment at a given farm was 3.6 per cent across the three years, while 10 of the 44 farms saw 20 per cent or more of available energy lost to curtailment. These amounts underestimate the total amount of spilled solar PV energy that could be utilised by 'behind-the-meter' storage as they exclude energy lost from oversizing the DC generation capacity compared to the AC export limitations at the point of connection.

Curtailment resulting from negative pricing, network constraints, and local limits amounted to, on average, 4.2 per cent, 5.3 per cent, and 4.2 per cent of available energy over the study period, respectively.

Some of the key takeaways are:

1. There was a marked increase in network constraint curtailment at farms in NSW and Victoria over summer 2021–22, likely attributable to the grid operator's management of transmission congestion and general system security.
2. There was a large amount of economic curtailment in late 2021 in Victoria, South Australia and to a lesser extent Queensland, however, this reduced to similar levels to previous years by the second quarter of 2022.
3. The greatest level of local limit curtailment was seen at four Victorian solar farms in the West Murray region in late 2019 and early 2020, due to 50 per cent caps on capacity placed by AEMO due to low system strength in this region that has many solar farms but is geographically distant from synchronous generation.

From June 2019 to May 2022, the average evening (5pm – 9pm) spot price has ranged from between 2.1 times higher in NSW to 5.3 times higher in SA than the average spot price during hours of peak solar generation (10am – 2pm). This consistent uplift in the evening spot price across all regions is reflective of the high residential demand coinciding with the ramping down of rooftop and utility solar. This price differential represents an opportunity for intraday price arbitrage through the deployment of battery storage.

Figure 1 shows the average total value of selling all solar PV curtailed energy each year over the three years to May 2022 at the evening average spot price is $119M per year, where the breakdown of this amount across QLD, NSW, VIC, and SA is $61.2M, $27.1M, $22.8M, and $7.5M, respectively. This is equivalent to 36 per cent of the annual total spot market revenue (ignoring loss factors) across the solar farms in this study. The value of curtailment resulting from negative pricing, network constraints, and local limits are $29.1M, $50.7M, and $38.8M, respectively.

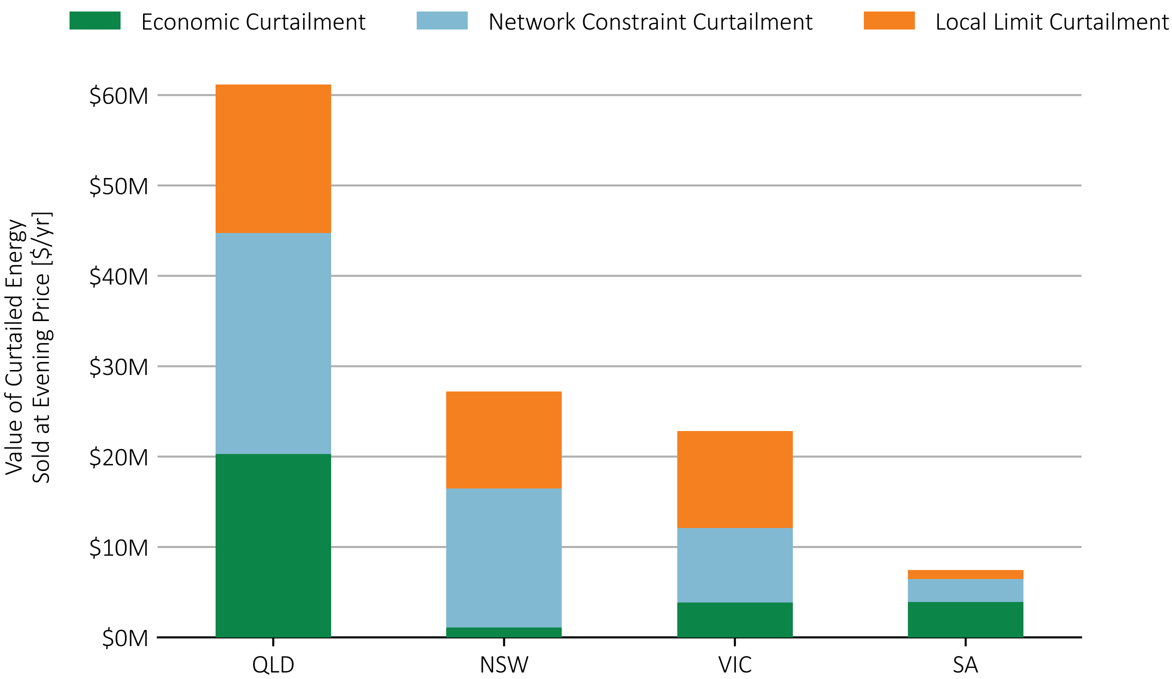


Figure 1. Average annual value of curtailed energy if stored and sold at evening peak price.

2 Noting that data from 2019 and 2022 are incomplete.

Several regulatory barriers exist to realising this potential:

- The IRP rule change maintains the requirement for generators to negotiate use of system charges with the transmission operator. Unreasonable charges could undermine the business case for the deployment of storage if not located behind the existing generator connection point.
- If trading across the local network, the generator would need to be exempt from local constraints established either by AEMO or the transmission operator. Alternative approaches to this are being considered by the Energy Security Board (ESB) through the congestion reform work program.
- Retrofitting storage at existing solar farms could result in the generator being required to renegotiate generator performance standards and connection agreements with AEMO and NSPs in respect of the existing solar farm. This provides a material financial risk to investors in the existing generator asset.

To meet the target of net zero emissions on the NEM by 2050, the volume of energy from clean, renewable sources needs to rapidly increase. Harnessing existing solar generation currently lost to curtailment through co-located storage could be a more efficient pathway to emissions reduction than building the equivalent volume of additional solar and wind projects from the ground up.[3] Conservatively, harnessing this additional renewable generation and dispatching it when it is needed would reduce the emissions of the NEM by 606kt CO_2-e. This is equivalent to taking approximately 300,000 Australian motor vehicles off the road. The large volume of solar energy currently being curtailed at large-scale solar (LSS) farms on the NEM presents a promising revenue stream and a source of significant emissions reduction.

3 Especially if the additional benefits of storage in terms of system security and opportunities in ancillary service markets are considered.

INTRODUCTION

The Australian Energy Regulator (AER) reported that 16 GW of thermal generation, or 61 per cent of the current coal fleet in the National Electricity Market (NEM), is expected to retire over the next two decades [1]. Simultaneously, variable renewable energy capacity on the NEM will need to increase three-fold by 2030 and nine-fold by 2050 to meet forecast electricity demand under AEMO's draft 2022 Integrated System Plan [2]. This fast-approaching retirement of aging thermal generation assets and the need to firm up expanding volumes of renewable generation is fuelling opportunities for investment into hybrid[4] facilities that are capable of bi-directional flows of power to and from the grid. This growth has led to the Australian Energy Market Commission (AEMC) creating the new Integrated Resource Provider (IRP) participant category, aimed at addressing some of the limitations in the National Electricity Rules (NER). Primarily, the IRP category aims to open the market up to greater participation by batteries by simplifying and clarifying the registration, bidding and dispatch processes for bi-directional flow assets while allowing flexibility in connection arrangements such as DC-coupled systems.

ARENA's Generator Operations Series has reported on many of the challenges facing large-scale solar farms on the NEM, one of them being curtailment. While curtailment is now a well-understood challenge facing solar developers and investors in Australia, what is less well understood is what the value of this curtailment could be if unlocked in terms of revenue and carbon emissions. The new IRP participant category is a step in the right direction to unlocking the value of curtailed energy, by allowing for the connection of a BESS alongside a generator, 'behind the meter' and effectively allowing the battery to be 'charged' directly from the solar farm, which could occur when solar energy would otherwise be curtailed. The ESB is also considering reforms that could make it easier for market participants to trade energy behind a congestion point using 'front of meter' battery storage [3].

This study quantifies the levels of curtailment at 44 LSS generators on the NEM over the 3 years from June 2019 to May 2022. The value of this curtailment is estimated by assuming it can be stored and then sold later each day.

Dalrymple Energy Storage for Commercial Renewable Integration (ESCRI) Battery. Image Credit: ElectraNet.

4 Hybrid systems consist of multiple technology types (e.g., a solar and battery system), which do not use shared equipment, such as a single inverter for two distinct technologies [20].

THE INTEGRATED RESOURCE PROVIDER RULE CHANGE

THE CURRENT NATIONAL ELECTRICITY RULES

Currently the NER require storage unit participants that have a nameplate rating of 5 MW or more to register and participate in the NEM as both a Market Generator and a Market Customer (Scheduled Load). As a result, a storage participant must provide separate bids to both generate and consume electricity and will receive separate dispatch objectives from the AEMO. An exception is made in the case of a battery system that is not configured to purchase energy from the grid at all, in which case registration as a Market Customer is not required [4].

Under this framework, there is significant administrative and regulatory complexity, and a co-located battery receives no recognition for the way it interacts with the adjacent solar or wind farm.

In practice, all existing storage facilities have negotiated a position with the local NSP whereby they do not pay Transmission Use of System (TUOS) and Distribution Use of System (DUOS) charges. However, the AEMC recognised that there was a lack of clarity as to how TUOS and DUOS charges apply to storage and hybrid facilities under the current rules, and they are therefore treated differently depending on how the NSP interprets the NER. So when a developer is considering the feasibility of a storage or hybrid project, there is uncertainty on the quantum of its operating costs (i.e., whether or not it will need to pay TUOS and DUOS) until it has finalised negotiations with the NSP on a case-by-case basis.

CHANGES TO THE NATIONAL ELECTRICITY RULES

The definition of storage in the NER has essentially changed. To avoid referring to energy storage explicitly, the new term "bidirectional unit" (or BDU) has been introduced for any unit that functions as both a load and a generator. The AEMC's position is that categorising storage or hybrid facilities based on their technology is unnecessary. Rather, different obligations will be attached to a unit based on the services it delivers to the market, such as generation, load, or both.

The IRP category will include a wide range of participants with bi-directional energy flows, including those who offer and consume energy, as well as those who provide auxiliary services such as storage, hybrid facilities, and aggregators of small generation and storage units [5].

Any new participant will be required to register as an IRP under the final rule if it has both generating capability (i.e., it is sufficient to register as a Market Generator on its own) and consumption above auxiliary load behind a single connection point. An existing participant who is registered as both a Market Generator and a Market Customer in regard to the same facility will be required to re-register as an IRP under the final determination.

The AEMC determined it would not be consistent with the rule's technology-neutral approach if it followed AEMO's rule change request which sought an exemption for storage units from the network charges. The IRP is not required to pay network charges automatically under the final rule. Rather, storage participants have the option of selecting the service they require and whether to acquire a negotiated or prescribed shared transmission service. Participants in the IRP category can make agreements with Transmission Network Service Providers (TNSPs) in the same way that existing storage participants can. TNSPs will negotiate pricing that is comparable to those negotiated for other transmission customers that receive the same service.

One of the key features of the final ruling by the AEMC in terms of arbitraging curtailed energy is that where solar and battery assets form part of the same IRP behind a single connection point, while scheduling and dispatch obligations will be set at the unit level for each asset, where possible, conformance with dispatch instructions will be measured in aggregate at the connection point [5]. This will mean that if a solar farm is constrained through dispatch instructions for a given interval and the battery part of the same IRP has been scheduled to generate a specific amount, the battery could discharge less than the scheduled amount and the solar farm could exceed the curtailment cap, provided the sum of the two assets' generation is equal to the sum of the dispatch targets for the solar farm and battery. However, strict conformance with the specific dispatch instructions to individual units will be enforced in some cases, e.g., where the storage asset is also contributing essential system strength services.

The introduction of aggregate conformance removes a key barrier for the use of co-located batteries to manage the curtailment of variable renewable energy (VRE) generators. For example, at the time when the Gannawarra Energy Storage System was commissioned behind the same connection point as Gannawarra Solar Farm, the project developers explicitly recognised that there was 'no formal pathway to guarantee curtailment mitigation' [6] [7]. This was because if a thermal constraint (for example) applied on the transmission line where the solar and BESS assets connected and this caused a binding constraint to cap the output of the solar farm, this constraint would be applied at the generator level, rather than at the connection point, meaning that energy from the solar farm could not exceed the cap even if the BESS was absorbing all energy above the cap such that the thermal capacity of the line was not exceeded. Under the new rule, if the solar and BESS were registered as an IRP,[5] this would be possible.

IMPLICATIONS OF THE REVISED NATIONAL ELECTRICITY RULES

Incumbent storage owners will need to assess their current positions under existing connection agreements, and keep in mind that the final rules include a transitory provision that states that the rules will not affect existing agreements. For new storage and hybrid projects, developers will need to negotiate tariffs and service levels with NSPs during the connection process to secure a negotiated transmission service with a negotiated resolution on Use of System (UOS) charges. Developers may also examine feasible strategies for decreasing future UOS charges, such as charging the battery behind the meter with renewable production or at the connection point with the NSP in hybrid systems. Finally, they should explore strategies for managing energy storage system charging, particularly how to mitigate maximum demand charges.

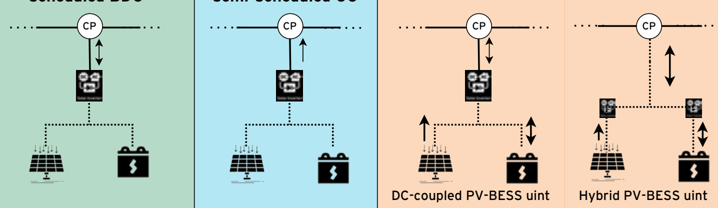
Gannawarra Energy Storage System. Image Credit: ARENA.

5 Note, Gannawarra Solar Farm and Gannawarra Energy Storage System are owned and operated by separate entities, so hybrid registration might also require a change in commercial structure in this case.

OPTIONS FOR CO-LOCATED SOLAR AND STORAGE

Under the new rules, there are several configuration options for both AC-coupled and DC-coupled systems. A DC-coupled system (i.e., a system where the solar and battery are situated behind a shared inverter) would register as an IRP and have the option of classifying the system as a single scheduled BDU (including VRE) or a single semi-scheduled generating unit (GU) subject to restrictions.[6] Alternatively, each resource could be classified independently. For example, a battery could be classified as a scheduled BDU and a VRE resource as a semi-scheduled GU.

AC-coupled systems will be required to have separate classifications for each unit but can collectively still register as an IRP. The implications for the different configurations under the new rules are shown in Figure 2 below.



	e.g., 20 MW solar farm comprised of 10 x 2 MW DC-coupled PV-BESS units			e.g., 20 MW solar farm and 10 MW / 20 MWh BESS share connection point only
	scheduled BDU	semi-scheduled GU	scheduled BDU & semi-scheduled GU (DC-coupled PV-BESS uint)	scheduled BDU & semi-scheduled GU (Hybrid PV-BESS uint)
BDU > 5 MW	✓	✓	✓	✓
Number of DUIDs	1	1	2	2
Consume from the grid	✓	x	✓	✓
One bidirectional bid with up to 20 bid bands	✓	x	✓	✓
One uni-directional bid with up to 10 bid bands	x	✓	✓	✓
AEMO will produce a UIGF for the solar resource or participants can opt to self-forecast solar resource	x	✓	✓	✓
Aggregated conformance would hinder – but not preclude – provision of FCAS	✓	✓	✓	✓

Figure 2. Schematic of different configurations for AC and DC coupled systems

One of the key reasons for retrofitting a battery to a generator on the NEM includes maximising its "value stack" by:

1. Allow the time-shifting of energy to allow greater utilisation of available network capacity (effectively using energy from the generator or behind the congested node which would otherwise have been curtailed).
2. Providing the generator with flexibility to access value from both energy markets during peak pricing periods and ancillary markets (e.g., the battery can receive FCAS revenues whereas the solar farm would otherwise pay FCAS charges).
3. Preparing for participation in any future revenue streams to the extent these are identified and regulated over time (e.g., further ancillary, inertia or capacity markets).

The remaining analysis in this study investigates the value proposition of unlocking the value of grid curtailment at the studied large-scale solar farms on the NEM. While this analysis assumes co-located storage as the means by which this value can be harnessed, it is important to note that standalone storage installed at points on the network experiencing congestion will also enable the capture of some of this curtailed solar energy and will play a critical role in the decarbonisation of Australia's energy network as a whole.

6 The main restriction is that the battery would not be able to charge from the grid above auxiliary load.

BREAKING DOWN CURTAILMENT AT EACH LARGE-SCALE SOLAR FARM

Estimates of available generation were modelled at each of the large-scale solar farms included in this study. A summary of the steps taken to model available solar PV generation at each site are:

1. **Data Collection:** Solcast[7] satellite data and NEMWEB generation and price data were obtained for each site.
2. **Potential Local Limit Identification:** Periods where a local limit may have applied to cap the generation of the solar farm outside of the NEM dispatch engine were identified.
3. **Tilt Detection:** The generation data was compared to theoretical generation profiles generated using the pvlib Python library [8] to determine the probable setup at each site (i.e., tracking or fixed-tilt).
4. **Plane-of-Array Irradiance and Cell Temperature:** Plane-of-array irradiance (POA) and cell temperature (Tcell) were calculated using the pvlib Python library, as in [9].
5. **Regression Model of Farm Output:** For each farm, a regression model was developed to calculate the expected output at each time interval.
6. **Regression Model Validation:** The regression models for all farms were validated by calculating the adjusted R2, mean bias error and root mean square error using 10 times repeated 10-fold cross-validation.
7. **Curtailment Calculation:** Curtailment was calculated as the difference between the modelled output from the regression models and the observed dispatched energy from AEMO's NEMWEB database.

More details on how this modelling was conducted, including the level of uncertainty, are available in the Appendix and ARENA's recent publication: *Benchmarking Large-scale Solar PV performance in Australia using satellite weather data* [9]. Observing the difference between available generation and actual dispatch data from AEMO's public NEMWEB database provided insights on when it was likely that each site's generation was being curtailed. The cause for curtailment has been broken down into the following categories:

1. **Economic curtailment**: occurring during negatively priced intervals in the spot electricity market.[8]
2. **Network constraint curtailment**: occurring when a site's semi-dispatch cap[9] was active, typically due to thermal, system strength, and other constraints.
3. **Local limit curtailment**: occurring when a local limit[10] was applied to constrain generation.
4. **Remaining difference**: This is any remaining difference between the modelled output and the observed output that could not be confidently attributed to any of the above causes.

Estimating curtailment that resulted from a local limit being applied is particularly challenging. This is largely because AEMO's NEMWEB database does not publicly record[11] identifiable tags indicating when local limits are being applied. This study has taken a conservative approach when defining active periods for local limits (see Appendix).

It is to be expected that some level of uncertainty will be involved when modelling solar PV generation. This inherent uncertainty means the cause of curtailment cannot always be identified as economic, network constraint, or local limit related. Any unexplained curtailment has been attributed to the 'remaining difference' category. Curtailment attributed to this category may be a result of either:

1. Inherent uncertainty in the modelling at short timescales [9] and/or,
2. Conservative definition used to identify periods of active local limits (see Appendix).

7 For more information on how Solcast estimates irradiance, see [23].

8 Any interval, both 5-minute and 30-minute, where the spot price was less than or equal to zero dollars per MWh.

9 When the semi-dispatch cap is active, the output of the solar farm must not exceed the maximum value directed by the NEM dispatch engine. These values are recorded in the DISPATCHLOAD table from NEMWEB [22].

10 Local limits refer to periods where the output of a solar farm is capped at a level below its AC capacity. This can be due to instructions from the network operator provided outside the dispatch engine, or can sometimes be due to issues with inverter availability.

11 AEMO began publicly recording identifiable tags for when local limits are being applied in November 2021.

Figure 3 ranks solar farms by the total energy dispatched to the grid as a percentage of available generation. This ranking provides a benchmark for the levels of curtailment experienced across the solar farms. The lowest level of average curtailment at a given farm was 3.6 per cent across the three years, while 10 of the 44 farms saw 20 per cent or more of available energy lost to curtailment.[12]

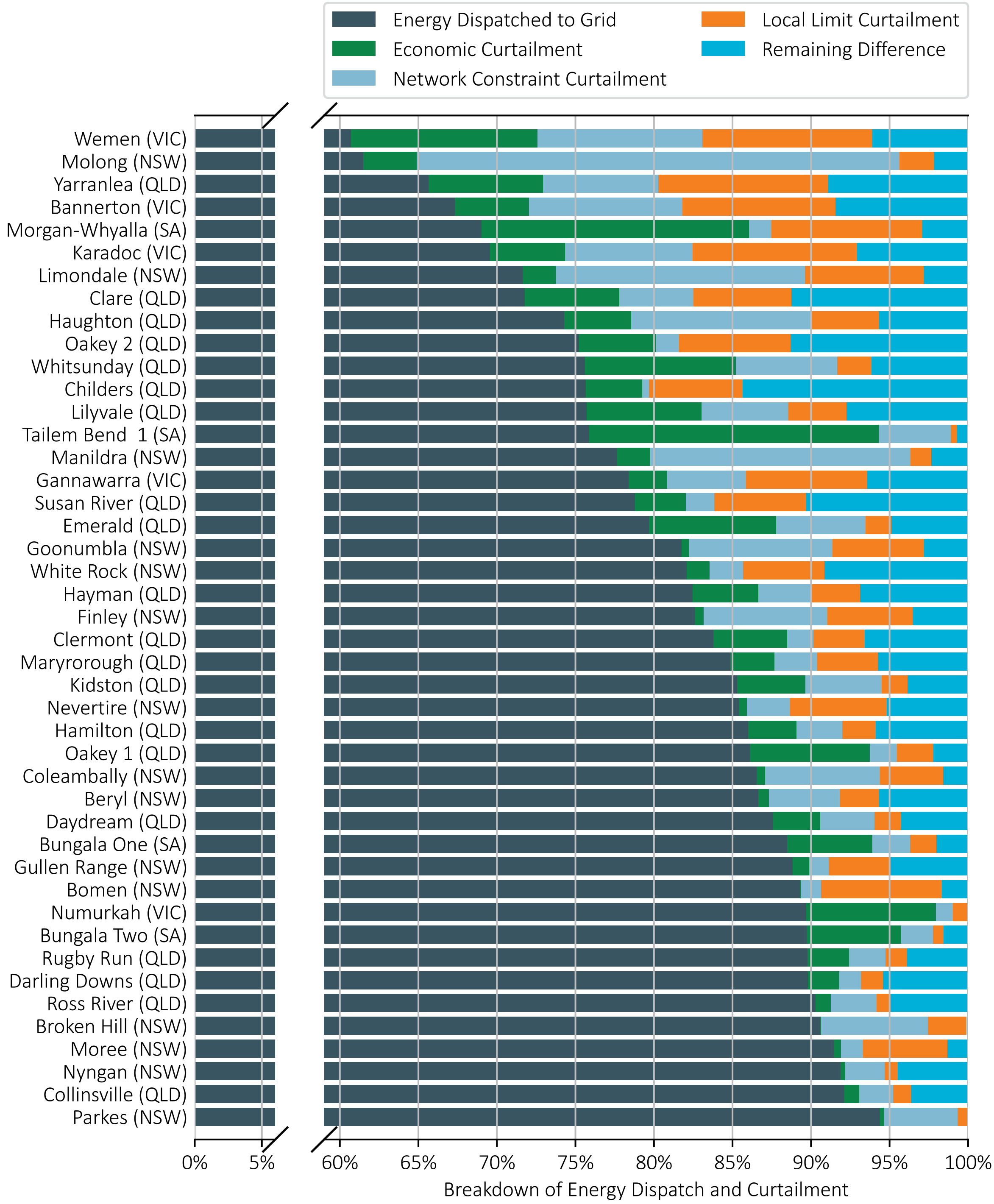


Figure 3. Breakdown of energy dispatched to the grid and curtailment in the three years from June 2019 to May 2022 across 44 solar farms connected to the NEM.

As noted, the 'remaining difference' has not been classified as curtailment in this study in order to be conservative, as this additional difference could readily be the result of satellite irradiance bias to overestimation or overfitting of the underlying regression models to training data which may be more optimistic than the given farm's overall performance. In addition, differences between modelled and

12 This excludes any energy classified as Remaining Difference.

observed output could be due to other performance issues (e.g., inverter availability) rather than locally enforced caps on capacity (local limit curtailment), which is a further reason to be conservative in the estimation of this form of curtailment. High values for remaining difference for individual solar farms are likely due to a greater variability in performance within the training dataset, resulting in a higher threshold for classification of the difference between modelled and observed output as 'local limit curtailment' (see Appendix for more details).

It is also worth noting that the actual financial impact of economic curtailment (and how quickly a solar farm will bid itself out of dispatch during negative price events) will vary across solar farms depending on how economic curtailment is treated in any offtake agreements. For example, a merchant solar farm may be comfortable generating for negative prices up to the LGC value, whereas a contracted farm may be required by the offtaker to minimise generation and may, or may not, receive compensation in this case depending on the terms.

Table 1. and Table 2. provide additional statistics about the percentage of energy curtailed at individual farms, averaged by state and by year. In the three years to May 2022, an average of 13.7 per cent of available energy was curtailed across the solar farms in the study. On average, the volume of curtailment in 2019, 2020, 2021 and 2022[13] was 13.1 per cent, 12.3 per cent, 15.4 per cent and 11.0 per cent of available energy, respectively.

TABLE 1 AVERAGE CURTAILMENT BY STATE

STATE	NUMBER OF SOLAR FARMS	CURTAILMENT [AVERAGE % OF MODELLED AVAILABLE GENERATION]			
		ECONOMIC CURTAILMENT	NETWORK CONSTRAINT CURTAILMENT	LOCAL LIMIT CURTAILMENT	TOTAL CURTAILMENT
QLD	20	4.5	3.7	3.5	11.8
NSW	15	0.9	7.7	4.1	12.7
VIC	5	6.4	6.9	7.9	21.3
SA	4	11.7	2.6	3.1	17.4
All	44	4.2	5.3	4.2	13.7

TABLE 2 AVERAGE CURTAILMENT BY YEAR

YEAR	CURTAILMENT [AVERAGE % OF MODELLED AVAILABLE GENERATION]			
	ECONOMIC CURTAILMENT	NETWORK CONSTRAINT CURTAILMENT	LOCAL LIMIT CURTAILMENT	TOTAL CURTAILMENT
2019*	2.2	5.6	5.4	13.1
2020	3.2	3.3	5.8	12.3
2021	6.8	5.5	3.1	15.4
2022*	1.9	7.2	1.9	11.0

Figure 4 visualises how different categories of curtailment have impacted different regions on the NEM over time. Curtailment resulting from negative pricing, network constraints, and local limits amounted to, on average, 4.2 per cent, 5.3 per cent, and 4.2 per cent of available energy over the study period, respectively. Some of the key takeaways are:

1. There was a marked increase in network constraint curtailment at farms in NSW and Victoria over summer 2021–22, likely attributable to management of transmission congestion and general system security.
2. There was a large amount of economic curtailment in late 2021 in Victoria, South Australia and to a lesser extent Queensland, however, this reduced to similar levels to previous years by the second quarter of 2022. This was largely due to the continued growth in distributed solar output and cooler than average weather conditions which reduced cooling loads [10]. In Queensland, outages due to the Queensland-NSW Interconnector upgrade trapping excess solar in the Queensland region has also contributed to negative price events [11].[14]

13 Noting that data from 2019 and 2022 are incomplete.

14 For a more detailed discussion of economic curtailment and the response of VRE generators to negative price events, see ARENA's recent publication: Negative pricing and bidding behaviour on the NEM [21].

3. The greatest level of local limit curtailment was seen at four Victorian solar farms in the West Murray region in late 2019 and early 2020, due to 50 per cent caps on capacity placed by AEMO in response to low system strength. While this specific issue has been largely resolved [1], solar farms in Victoria have seen even higher levels of curtailment in late 2021 from economic curtailment and network constraints, and certain individual farms across all regions continue to experience significant levels of local limit curtailment for other reasons, which is important to capture.

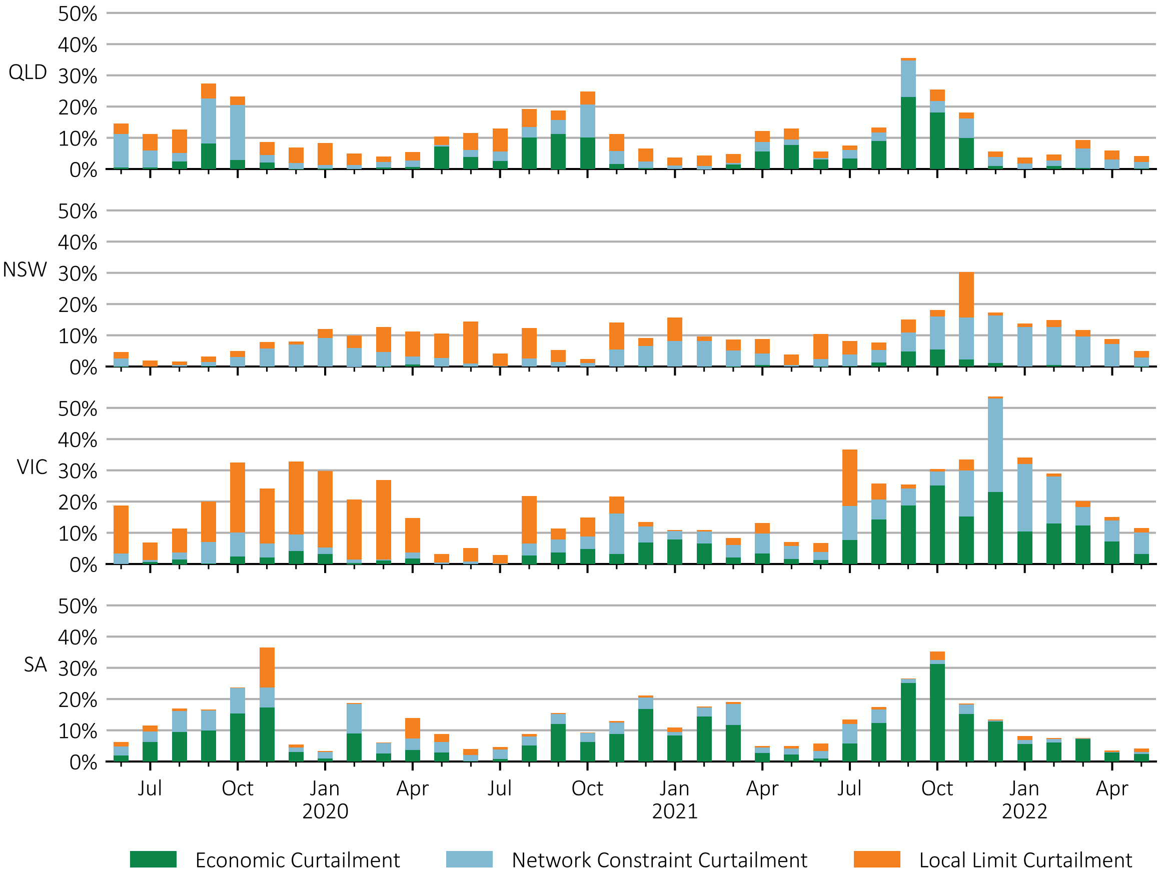


Figure 4. Breaking down curtailment types by state in the three years from June 2019 to May 2022. Values reflect curtailment as a percentage of total available generation for the given state in the given month at the included solar farms.

Gannawarra Energy Storage System. Image Credit: ARENA.

VALUING CURTAILMENT

The new Integrated Resource Provider (IRP) classification is a step in the right direction toward unlocking the value of curtailed energy. This study estimates what that value[15] is by assuming that each day, all curtailed energy is stored and subsequently dispatched during the evening period of peak demand.

Since the start of 2019 and up to May 2022, the average spot price over all time periods, during peak solar generation (10am – 2pm) ('peak solar price'), and during the evening peak demand (5pm – 9pm) ('evening peak price') is compared in Figure 5. In all years and states, the evening peak price exceeds the solar peak price by at least 59 per cent (as seen in NSW in June to December 2019). The evening peak price averaged more than 14 times the peak solar price in SA in 2021. On average over the three years to May 2022, the evening peak price ranged from 2.1 times the peak solar price in NSW to 5.3 times the peak solar price in SA. This consistent uplift in the evening spot price indicates the increased demand for more expensive fast ramping thermal generation in the evening as solar production ramps down.

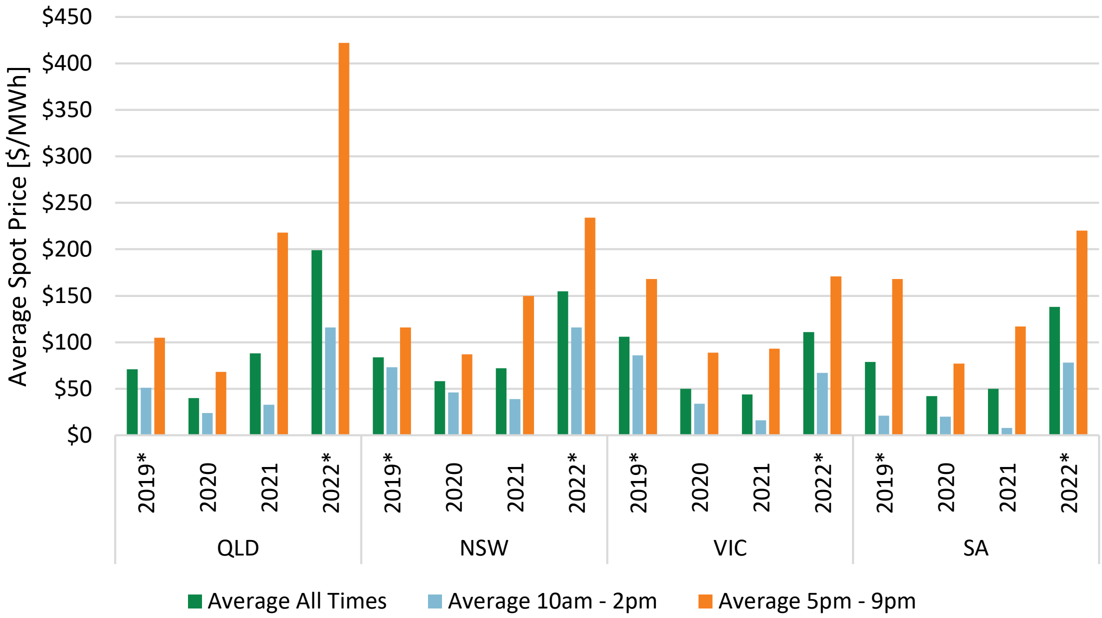


Figure 5. Comparison of average spot price, peak solar price, i.e., average spot price during peak solar hours (10am – 2pm), and evening peak price, i.e., average spot price during evening peak demand (5pm – 9pm). * The 2019 and 2022 datasets are incomplete.

Figure 6 shows the value of curtailed energy if it is stored and dispatched later that day receiving the evening peak price for that day. It also shows the average daily curtailed energy at each farm. The latter value can be used to inform the sizing of a potential storage system to be installed at the given location.

The average potential annual revenue from stored and shifted curtailment (arbitraged) is $2.7M, with the highest revenue being $7.4M. The revenues available are relatively well-distributed across the different regions, indicating that the potential benefit of a co-located storage asset is more associated with the volume of curtailment than the region. The total potential revenue across all farms is $119M per year, equivalent to 36 per cent of the annual total spot market revenue (ignoring loss factors) across the solar farms in this study.

The average daily curtailment at all farms is also presented in Figure 6, with the mean value across all farms being 68 MWh. Across all farms, the typical magnitude of curtailment in MW for a given five-minute interval where curtailment occurs is approximately 20–30 per cent of the AC capacity of the farm,[16] which could be used as a rough guide for the maximum power output of a battery to be installed to capture curtailed energy. With this sizing, capturing the average daily curtailment at an average farm would require a battery with approximately 3 hours of storage. For example, following this sizing strategy, the power and energy capacity of a battery co-located at a 50 MW_{AC} solar farm would be anywhere between 10 – 15 MW and 30 – 45 MWh, respectively.

15 This value does not consider the cost-benefit of the various connection configurations for co-located batteries.

16 For 5-minute intervals where curtailment was deemed to occur, the median magnitude of curtailment was 20 per cent of the AC size of the farm and the mean magnitude was 30 per cent of the AC size of the farm, on average across all farms.

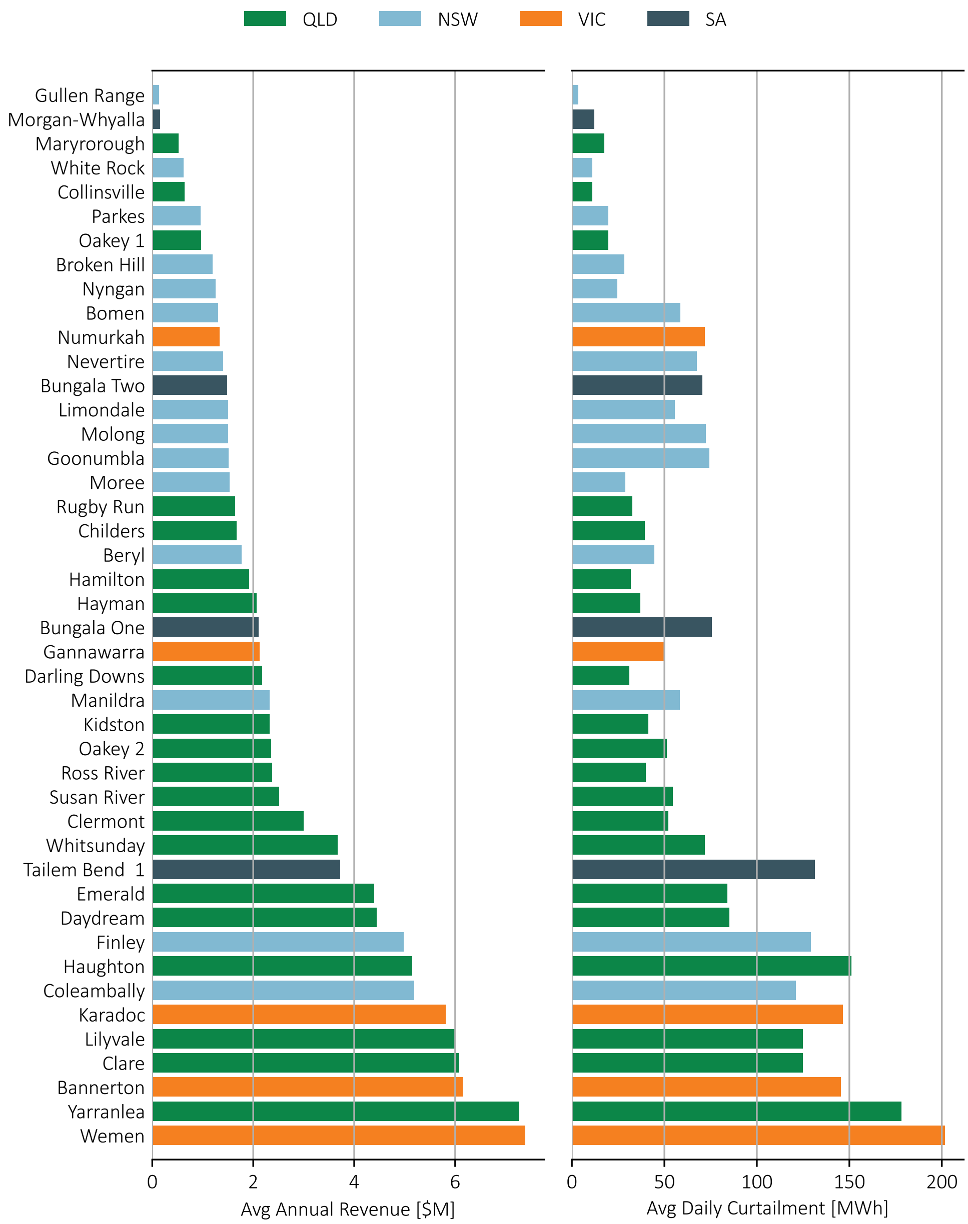


Figure 6. Average annual revenue from sale of curtailed energy during the evening and average daily curtailment.

The total volume of curtailed energy across all the solar farms studied is approximately 980 GWh per year, which is 16 per cent of the total annual generation across the solar farms in the study – or the equivalent of the annual generation of 7 average large-scale solar farms.

By state, the total curtailed energy comes to approximately 428 GWh in Queensland, 238 GWh in NSW, 223 GWh in Victoria and 93 GWh in South Australia. These values can be used to conservatively estimate the potential greenhouse gas emissions reduction if this energy were harnessed. In 2022, the projected emissions by state are 0.66, 0.64, 0.68 and 0.21 tonnes of CO_2 equivalent emissions per MWh for Queensland, NSW, Victoria and South Australia respectively [12]. These values would be higher at night when there is no solar generation, so the estimate that follows is conservative. Conservatively, harnessing the curtailed solar generation and dispatching it when needed would reduce the emissions of the NEM by 606kt CO_2-e per year. This is equivalent to taking approximately 300,000 Australian motor vehicles off the road [13] [14].

LIMITATIONS AND IMPLICATIONS

Two key sets of limitations need to be recognised with respect to the foregoing analysis.

First, the scope of this study only considers one of the many technical and commercial considerations relevant to the viability of a BESS installation co-located with solar. While there is a significant revenue stream available at several existing solar farms, this needs to be balanced against the risks involved. Significant capital outlay is associated given; high battery costs, limitations of existing electrical infrastructure onsite to incorporate newer BESS technologies, and the re-opening existing agreements with AEMO, NSPs, asset managers and operations and maintenance contractors, among others. By contrast, the revenue from arbitrage of curtailed energy may be relatively small compared to the potential revenues from a more sophisticated arbitrage strategy allowing charging from the grid and participation in FCAS markets and further ancillary, inertia or capacity markets that may be created in the future. Further, the commercial structure of battery tolling agreements may limit the control existing solar farm owners have over the operation of co-located storage. The findings of this paper may therefore be more useful in demonstrating the size of this untapped energy resource as a whole, as the applicability to individual solar farms depends on a broad range of factors not considered.

Second, the methodology used to quantify and value curtailed energy has several limitations:

- The analysis is based on historical data and does not attempt to forecast future volumes of curtailment or energy price trends.
- The 5-minute regional spot price is used in revenue calculations, ignoring 30-minute settlement prior to October 2021 and marginal loss factors. The latter could significantly reduce the available revenue depending on the farm's location.
- Curtailment attributed to local limits could also be due to inverter outages or other operational issues on site. Despite this type of curtailment being conservatively calculated, it is still possible that some figures have been overestimated.
- While the estimated volumes of curtailment are likely to be close to the actual curtailment on average, estimates at individual farms may be higher or lower than what actually occurred due to modelling uncertainty, especially due to bias introduced by the use of satellite data over short time periods and bias that may have been introduced by the limited training dataset.
- All curtailed energy was assumed to be captured and sold at the evening peak price, when in reality, the volume of energy captured each day and the price achieved in the sale of this energy will be highly dependent on the capacity and volume of the battery and the specific trading algorithm adopted by the operator.

Nevertheless, the analysis demonstrates that a significant volume of renewable energy is being curtailed at solar farms across the NEM due to negative prices and physical network limitations. The installation of storage assets either co-located with solar farms or at congested points on the network to shift this curtailed energy to be dispatched during the period of peak evening demand represents a $119M per year revenue stream based on the historical generation, price and weather data from June 2019 to May 2022. Several projects at various stages of development are already proceeding in co-locating BESS assets with solar farms, including both retrofits of existing solar farms (e.g., Childers, Susan River and Nevertire Solar Farms [15]) and as part of new solar farm developments (e.g., New England and Wandoan South Solar Farms [16]).

Furthermore, there are several reasons to believe that the size of the potential energy and revenue lost to curtailment is likely to grow. One scenario explored in AEMO's draft 2022 Integrated System Plan states that by 2050 the proportion of VRE curtailment increases to approximately 20 per cent of total available output [2], so the curtailed energy and revenue figures are conservative relative to the volume of curtailment likely to be seen in the future. The study is also conservative in terms of the assumed price at which arbitraged energy is sold, as it is based on the past three years of price data, giving less weight to the recent surge in electricity prices across the NEM [17].

Thus, the value of curtailed energy at solar farms on the NEM is already significant, but may also increase substantially in the coming years and decades. While commercial and regulatory barriers remain, the introduction of the IRP participant category will improve the likelihood that this untapped energy resource will be captured through the deployment of storage. Unlocking this renewable energy resource would reduce emissions on the NEM by over 600kt CO_2-e per year and could be a critical step in achieving the target of net zero emissions on the NEM by 2050.

APPENDIX: MODELLING METHODOLOGY

The modelling in this paper builds on the work of previous papers in the Generator Operations Series:

› *Large-scale solar operations* [18].

› *Benchmarking Large-scale Solar PV performance in Australia using satellite weather data* [9].

The analysis was carried out as follows:

1. **Data Collection:** Solcast satellite data and NEMWEB generation and price data were obtained for each of the 44 solar farms in the study across the study period from June 2019 to May 2022 inclusive. The 44 generators were selected as those which had achieved at least 95 per cent of their maximum capacity prior to December 2020, meaning they had normal generation data for at least half of the study period.
2. **Potential Local Limit Identification:** Periods where a local limit may have applied to cap the generation of the solar farm outside of the NEM dispatch engine were identified as periods where the total deviation in output across three consecutive periods was less than 1 per cent of the AC capacity of the farm. These 'potential local limit' periods essentially identify periods where the profile flattens. Days where at least three such consecutive periods occurred were classified as days to which a local limit may have applied.
3. **Tilt Detection:** The generation data was compared to theoretical generation profiles generated using the pvlib Python library. The procedure used here was identical to that used in [9], subject to the following adjustments:
    a. Typical loss values were applied within the pvlib generation module using the PVWatts method, with 1.5 per cent soiling, 1.0 per cent mismatch, 2.0 per cent wiring, 0.5 per cent connections and 1.5 per cent light-induced degradation assumed. The need to include losses was identified by the model's difficulty in distinguishing fixed-tilt from tracking arrays at some of the additional farms included in this study.
    b. Days to which a local limit may have applied were excluded from the training dataset based on those identified using the procedure identified at item 2 above, rather than through manual identification of local limit periods.
4. **Plane-of-Array Irradiance and Cell Temperature:** Plane-of-array irradiance (POA) and cell temperature (Tcell) were calculated using the pvlib Python library, as in [9].
5. **Regression Model of Farm Output:** For each farm, a regression model was developed in the same form as that used in [18]. In addition, Fourier terms were added to capture additional daily and annual trends cycles not captured by the irradiance and temperature variables [19]. One sine and cosine pair were added with a daily period, and one sine and cosine pair were added with a yearly period. The training dataset was selected using the same exclusions as the Tilt Detection step, plus an additional exclusion similar to [18] based on the 5-minute performance ratio falling between 0.7 and 1.0, reflecting the typical expected operation of the farm when not subject to constraints or availability issues.
6. **Regression Model Validation:** The regression models for all farms were validated by calculating the adjusted R^2, mean bias error and root mean square error using 10 times repeated 10-fold cross-validation. The lowest cross-validated adjusted R^2 was 0.94, the maximum relative mean bias error magnitude was 0.37 per cent, and the maximum root mean squared error was 11.5 per cent. Overall, the metrics and visual inspection of the modelled versus actual results both within the training dataset and applied to the remainder of the dataset indicated that the model and training exclusions were appropriate to accurately model unconstrained performance across the sites in the study.
7. **Curtailment Calculation:** Curtailment was calculated as the difference between the modelled output from the regression models in items 5 and 6 above and the observed dispatched energy from AEMO's NEMWEB database.
    a. Economic Curtailment was counted only for periods where the 5-minute spot price or 30-minute settlement price (prior to October 2021) was lower than 0.
    b. Network Constraint Curtailment was counted only for periods where Economic Curtailment did not apply and the Semi-Dispatch Cap flag for the given farm was equal to 1.
    c. Local Limit Curtailment was counted where neither Economic nor Network Constraint Curtailment applied, where 'potential local limit' periods had been identified, *and* where the difference between the modelled output and the observed dispatch was greater than the 75^{th} percentile of the positive errors from the regression model. The latter condition was intended to be conservative and ensure that only periods where the actual output was consistently well below the modelled output, by a margin larger than the typical error in the model itself, were counted. This is particularly important given the higher errors in the satellite irradiance data at the high time resolution: [9].

Note, the methodology above allows for the fact that for individual 5-minute periods, the Economic Curtailment or Network Constraint Curtailment can be negative, i.e., the modelled output for a given interval may be less than the observed output. This is included for these types of curtailment because there is a high degree of confidence that curtailment would have been occurring (with data sources from AEMO on which to directly base the classification), and the errors in the model average out when summed over days, months and years such that the overall curtailment value is positive, i.e., indicates that generation was lost due to curtailment.

To calculate the value of curtailed energy:

1. The amount of Economic Curtailment, Network Constraint Curtailment, and Local Limit Curtailment for each solar farm on each day in the study period was calculated using the method described above.
2. The average spot price during the evening peak demand period (5pm – 9pm) ('evening peak price') was calculated for each day in the study period for each solar farm.
3. The value of the curtailed energy for a given day at a given solar farm for each curtailment type was obtained by multiplying the amount of curtailed energy from step 1 by the evening peak price in step 2.

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Further information is available at
arena.gov.au

Australian Renewable Energy Agency

Knowledge Sharing Team
knowledge@arena.gov.au

Postal Address
GPO Box 643
Canberra ACT 2601

Location
2 Phillip Law Street
New Acton ACT 2601

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