THE GENERATOR OPERATIONS SERIES

Report One: Large-scale Solar Operations

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Australian Government
Australian Renewable Energy Agency

ARENA

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EXECUTIVE SUMMARY

In 2016 ARENA and the CEFC invested in 14 large-scale solar (LSS) projects that have played an important role in accelerating the early development of the large-scale solar industry in Australia and the integration of utility-scale renewable energy generation in the National Electricity Market (NEM). This report presents the first in a series of analyses of the detailed operational data from those early projects. It provides a valuable perspective on how actual project performance has differed from the forecasts that were used to justify investment decisions.

The key lessons can be seen in three main areas:

1. PROJECT PERFORMANCE

- Curtailment had a dramatic impact on actual performance ratios.
- Local grid conditions were the major determinant of losses from dispatch constraints and plant derating.
- Negative pricing impacts increased significantly in 2020, particularly for Queensland projects.
- Initial project forecasts consistently underestimated residual losses and curtailment, while capacity factors were generally overestimated.
- Sponsors have worked with a range of participants, including EPC contractors and equipment providers to resolve immediate project issues.
- The Australian Energy Market Operator (AEMO) and Transmission Network Service Providers (TNSPs) are implementing measures in several key regions to address system strength and thermal constraint issues as the grid evolves to accommodate more renewables.

2. OPERATIONAL EXPENDITURE (OPEX)

- Initial project forecasts underestimated OPEX, on average, with several projects substantially over budget.
- There was significant variation between projects in terms of the most significant contribution to OPEX costs.
- Frequency Control Ancillary Services (FCAS) costs were both a significant expense and a major operational challenge for several projects, although this reduced from 2019 to 2020 as FCAS prices have fallen and several projects implemented self-forecasting.
- The failure of critical equipment, especially inverter power stack failure, and the lack of readily available spares were a major operational challenge for asset managers.
- LSS generators, and the industry of suppliers and service providers, have demonstrated resilience by resolving and adapting to these issues over time.

3. PROJECT REVENUES

- Spot market revenue across the LSS Project Portfolio fell from 2019 to 2020, largely due to the fall in average spot market prices across the NEM.
- Most of the LSS projects have Power Purchase Agreements in place for most if not all of their output, and this provides some protection from the observed market price movements, including the increase of negative pricing events.

These lessons will help inform the substantial additional investment and project development that is now required if Australia is to decarbonise its economy.[1]

1 The AEMO notes in its 2020 Integrated System Plan that distributed energy will provide as much as 22 per cent of total underlying annual energy consumption by 2040, with more than 26 gigawatts of additional renewable energy required to replace coal-fired generation in that period. This is alongside a further 6-19 gigawatts of new dispatchable resources.

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INTRODUCTION

In 2016 the Australian Renewable Energy Agency (ARENA) funded 12 LSS projects under a $100 million competitive grant round. Alongside the ARENA grant funding, the Clean Energy Finance Corporation (CEFC) delivered a long-term debt finance program, to both ARENA grant recipients and other projects, with the CEFC finance available to projects, including those which had not secured offtake agreements prior to ARENA grant allocation and financial close.

This first paper in the Generator Operations series analyses operational data from these projects.

Recipients of ARENA funding agreed to share data and information (some of which is confidential) through ARENA's Knowledge Sharing Program. This knowledge is presented to industry to help inform future investment decisions and assist in strengthening the commercial viability of renewable energy generation. Two additional projects subsequently signed up to knowledge sharing obligations, bringing this portfolio to 14 projects totalling 603 MW (the "LSS Round Projects"). The CEFC provided debt finance to eight of the LSS Round Projects. The location and capacity of each project is shown in Figure 1.

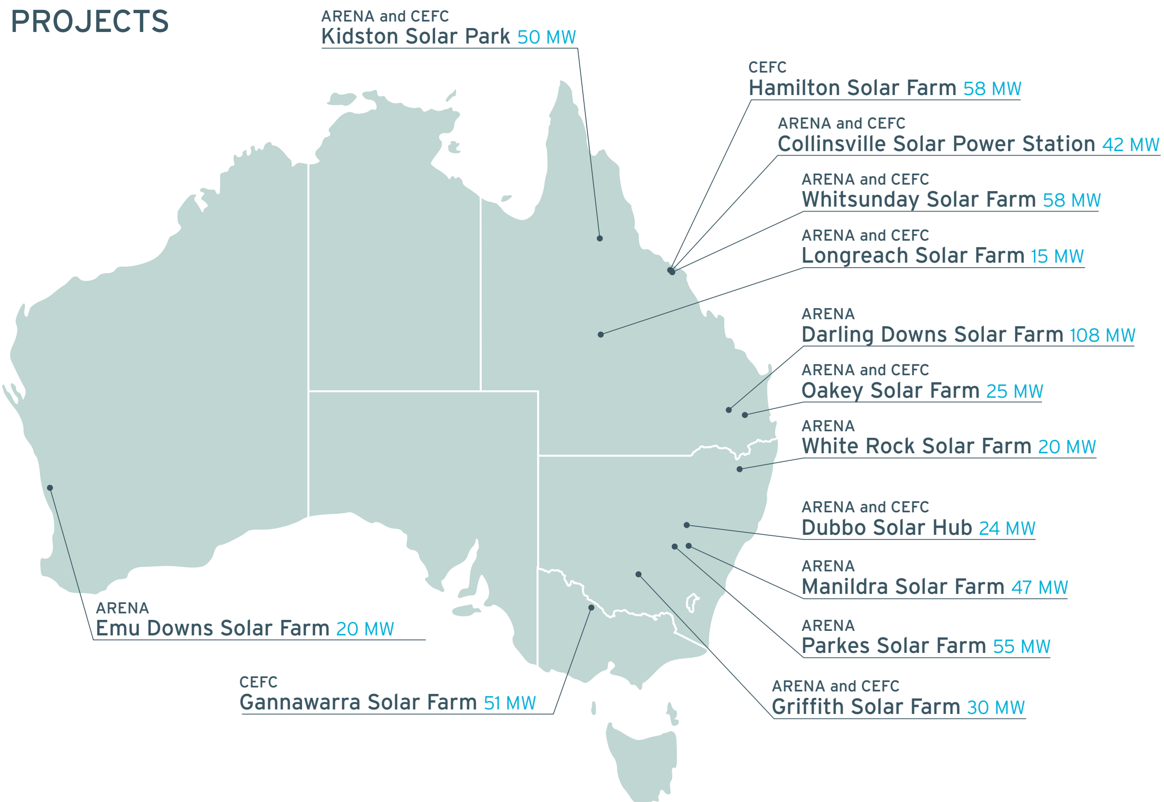

Figure 1. This map plots the location and nameplate capacity of the projects from the LSS Funding Round along with their funding source.

In January 2020 ARENA published Insights from the First Wave of Large-Scale Solar Projects in Australia https://arena.gov.au/assets/2020/01/insights-from-the-first-wave-of-large-scale-solar-projects-in-australia.pdf [1], a report that shared learnings and analysis from the LSS Round Projects, focussed on the hurdles to achieving financial close, construction, and practical completion.

In 2021 ARENA commissioned a series of studies that builds upon the first report by exploring the first two years of operations across the 14 projects. These projects are among the first of their kind developed in Australia. This series of studies presents key learnings from operational data of some of the longest operating large-scale solar generators in this nation. Each study will focus on a group of relevant issues such as performance ratios (PR), curtailment, capacity factors, marginal loss factors, financial performance, operational challenges, and energy storage considerations.

Private sector investors, developers and operators, who will play an important role in delivering this renewable energy infrastructure, will benefit from detailed analysis of real life market experiences in prioritising these substantial investment decisions. While ARENA has noted that the building, owning and operation of large-scale solar farms in Australia no longer requires grant funding, CEFC finance remains critical to filling market gaps. This includes accelerating investment in new renewable energy generation, storage, transmission and grid infrastructure, working with the broader industry to respond to emerging market, technology and operational developments.

The first two years of operations across the LSS Round Projects have been an opportunity for learnings for project sponsors, equipment providers, AEMO and Transmission Network Service Providers. However, these learnings have not come without challenges.

For feedback, ideas and innovation, please contact ARENA's Knowledge Sharing team at knowledge@arena.gov.au.

SECTION ONE: PERFORMANCE RATIO, CURTAILMENT AND CAPACITY FACTOR

This section explores how performance ratios (PR), curtailment and capacity factors compare across projects, while reflecting on what was forecast for these metrics at the time of financial close. The CEFC has supplemented this information with commentary drawn from the experience of the Post-LSS Round Projects.

1.1 PERFORMANCE RATIOS – THE LSS ROUND PROJECTS

Figure 2 compares the forecast (at financial close for the first year of operation[2]) and corrected[3] PR (across 2019 and 2020) for each of the LSS Round Projects. Project numbers are selected randomly for the purpose of anonymity. The performance is broken down visually using a stacked bar chart. Across 2019 and 2020, the average uncorrected PR across the LSS Round Projects ranged from 55.8 per cent to 84.4 per cent, with the average being 73.1 per cent. In 2019, one project's uncorrected PR fell below 50 per cent. The corrected PR had an average of 78.4 per cent, ranging from 73.9 per cent to 86.3 per cent. The PR guarantee promised by EPC contractors changes from project-to-project, but typically sits around 80 per cent.

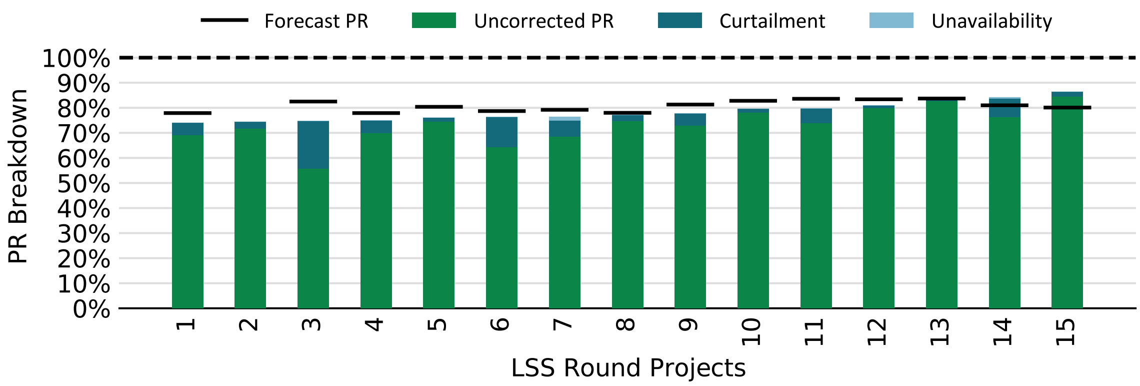

Figure 2. Actual PRs achieved across 2019 and 2020. PR Forecasts were submitted in Full Applications by the LSS Round Projects. Dubbo's South Keswick and Narromine sites have been treated as separate projects. It was not clear what the PR Forecast was for one project.

Boxplots in Figure 3 describe statistics on how curtailment and unavailability[4] impacted performance across the portfolio. On average across 2019 and 2020 curtailment and unavailability reduced performance by 5.1 per cent and 0.2 per cent respectively. In 2019, curtailment almost reduced the performance of one project by a quarter.

2 Only two of the LSS Round Projects generated for the entirety of 2018 whereas all except one project generated for the entirety of 2019. For consistency, the first year of generation is taken to be 2019.

3 Corrected for curtailment and unavailability.

4 Losses experienced by the solar farm due to site downtime or site outages.

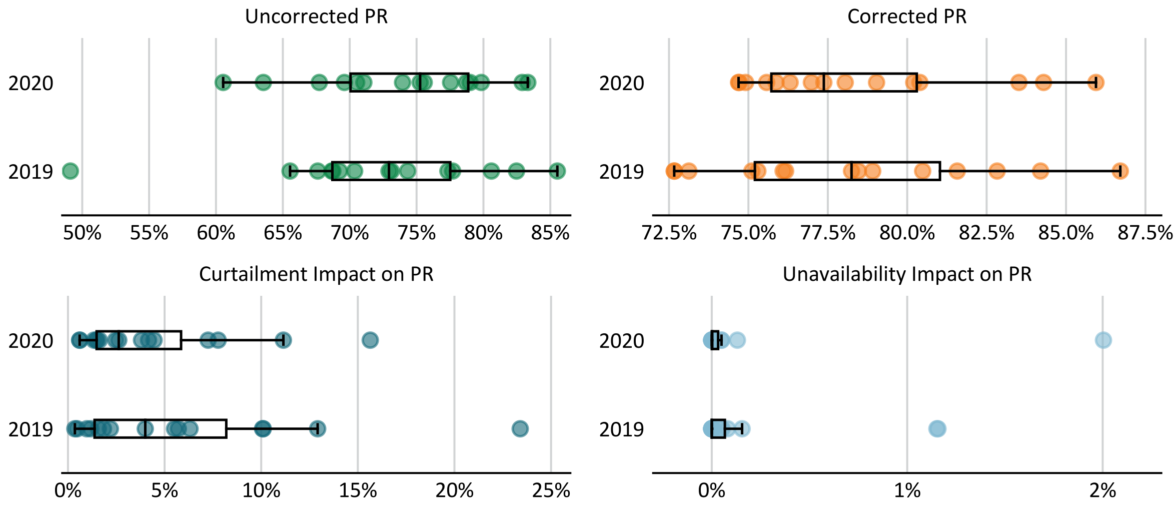

Figure 3. PR breakdown box plots for the LSS Round Projects.

This analysis highlights the dramatic impact of curtailment on the performance ratio of LSS Round Projects. Indeed, during the measurement period there were some significant curtailment events in certain regions of the grid where a number of solar projects are located, including a period spanning 2019 to early 2020 when solar farms in the West Murray Regions were constrained by 50 per cent to avoid the risk of uncontrollable voltage oscillations. This curtailment was ultimately resolved by an inverter tuning solution. North Queensland solar farms also experienced a number of constraints to manage local grid conditions.

However, once curtailment and unavailability are accounted for, there is a much greater degree of consistency in terms of performance across the portfolio.

POWER STACK FAILURES

Inverter availability has been one of the most material issues at several of the LSS Round Projects, which has often related to Power Stack failures. The Power Stack is a group of Insulated Gate Bipolar Transistors (IGBT) that are a core piece of power electronics within the inverter.

In the context of large solar inverters, the IGBT has been known to dissipate significant amounts of heat close to power electronics. To address this, IGBT's are stacked in parallel and mounted to a heat sink, however there are limitations on the amount of IGBTs that can be stacked as inefficiencies can begin to occur. If there are manufacturing issues or if the heatsink adhesion fails, then overheating can occur and result in failures.

For two projects, Power Stack failures began in November 2019 and lasted for six months. These issues were related to an industry-wide issue that an inverter manufacturer was facing and has since been resolved.

The corrected PR accounts for all losses experienced at each project (e.g., module degradation, soiling, module temperature losses, inverter efficiency, wiring losses, etc.) excluding those from curtailment and unavailability. All losses, except those from curtailment and unavailability, explain the difference between the corrected PR and an idealised solar farm operating at STC efficiency with no losses, which would theoretically have a PR of 100 per cent. Of these, the largest single contributor to losses is module temperature losses. Across the LSS Round Projects at financial close, forecast losses due to module temperature were estimated as ranging from 4 per cent to 10 per cent. Residual losses after module temperature losses are accounted for were forecast to range from 9 per cent to 18 per cent.

The distribution of temperature losses and residual losses observed at the LSS Round Projects in 2019 and 2020 is shown in Figure 4. Across 2019 and 2020, temperature losses and residual losses averaged 6.5 per cent and 15.0 per cent respectively.

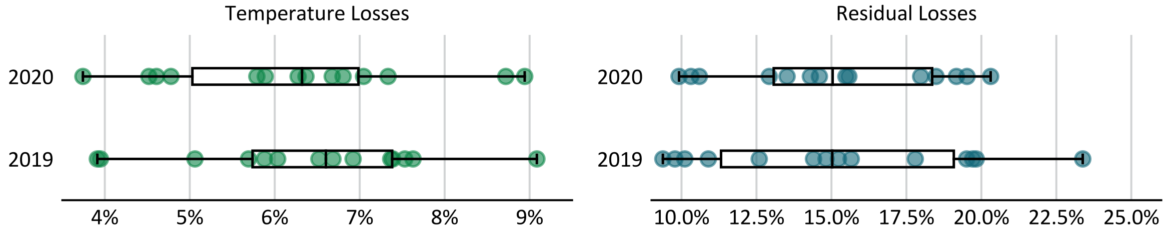

Figure 4. Estimated losses due to module cell temperature and residual causes explaining the difference between the corrected PR and a PR of 100 per cent, representing a solar farm operating at STC efficiency with no losses.[5]

Temperature losses were similar to what was forecast both in terms of the average and spread of the data. Given 2019 and 2020 were the hottest and fourth hottest years on record in Australia, temperature losses shown here may be underestimated as a result of some missing periods of data for warmer months at some projects. Residual losses were substantially higher on average than expected at financial close, with a wide range of values across the portfolio. In general, residual losses that exceed estimates are related to either ongoing performance issues (modules, inverters etc.) or one-off incidents that are either isolated events or rectifiable defects.

1.2 CURTAILMENT – THE LSS ROUND PROJECTS

At the time that the LSS Round Projects were achieving financial close there was a relatively small number of large-scale solar projects connected in Australia and curtailment was not considered a significant risk. Each successful applicant of ARENA's LSS funding round submitted detailed project financial models during the application stage that included confidential information about how investors accounted for expected losses to generation across a project's lifetime. Some of the common considerations contributing to lost generation across the LSS Round Projects include weather, degradation, unavailability, parasitic losses, and marginal loss factors. Curtailment was rarely included in these models at the time of ARENA submission, although it is possible that curtailment studies may have been subsequently commissioned for incoming investors at financial close.

GRID AUGMENTATION

One project experienced grid curtailment (about 3 per cent lost generation in 2020) since commissioning due to reduced loads in the area and a low-capacity grid transformer. The low load in the area pushed more electricity to the (now upgraded) network transformer, saturating (earlier) its capacity and therefore further curtailing production. The asset manager worked closely with the local grid operator and supported the retrofitting of the grid transformer (new cooling system) and resolved the local grid constraint by the end of October 2020. The owner of the project made a financial contribution to solving this issue and no curtailment has occurred, in this way, since the upgrade.

Today, curtailment is considered one of the major risks facing the LSS Round Projects and all other large-scale solar generators connected to the National Electricity Market (NEM). In AEMO's first Quarterly Energy Dynamics (QED) report released in 2017, the word curtailment is not mentioned. Today, AEMO's QED reports have lengthy sections devoted to summarising variable renewable energy (VRE) curtailment across the industry as it is now a major risk for owners, operators, and investors.

5 Projects that provided insufficient module temperature data to obtain a representative yearly value for temperature losses without seasonal distortions. Three projects were excluded on this basis.

SYSTEM SIZE AND CURTAILMENT

One of the LSS Round Project's system size was determined by first ensuring it fell under the local network's available capacity, where this availability materialised through a grid connection process completed prior to financial close. Post financial close the grid connection process and final GPS negotiations were completed to define the project's technical operating parameters, resulting in a 4 per cent smaller AC capacity. Construction then began and was substantially completed on this reduced AC system size.

The commissioning process began and identified a thermal constraint within the broader network infrastructure as well as rapid load fluctuations in the network. The network operator then de-rated (i.e. reduced the allowable maximum capacity of the asset for an extended period) the capacity of the plant by 26 per cent. Modifications were eventually made to optimise output and the plant operates today derated at approximately 14 per cent. This limit is applied on an ongoing basis to protect the network and continues to significantly reduce the amount of power exported to the grid.

In January 2020, the network operator committed to the permanent resolution of the curtailment for the site by utilising a second incoming feeder to the transformer. This would enable generation without curtailment, however significant upgrades of infrastructure and modifications to protection settings are required to manage higher fault levels that occur in this configuration. The work was targeted for completion in March 2021 and will require no financial investment from the LSS Project, other than some modification to the SCADA system.

This project has estimated that approximately 12 per cent and 7 per cent of generation was lost in 2019 and 2020 respectively when compared to what was budgeted at financial close and curtailment from constraints has been largely responsible for this.

Whitsunday Solar Farm

As Australia's generation technology mix rapidly changes, the task of ensuring that the power system constantly operates in a secure state has become increasingly complex. For AEMO to maintain a secure balance of the energy supply, a wide range of factors must be considered, including the capacity of transmission network components, the uncertainty and variability of renewable resources, and the ability of the system to withstand credible contingency events. In each 5-minute dispatch interval, AEMO's National Electricity Market Dispatch Engine (NEMDE) must determine the combination of generation sources that will achieve the least cost of energy, subject to anywhere between 600 and 1000 dispatch constraints [5].

Curtailment has been categorised below to either occur from dispatch constraints,[6] negative pricing events,[7] or other types of curtailment.[8] In addition to dispatch constraints, self-imposed curtailment has been increasingly employed by asset owners as a means of avoiding exposure to negative pricing events.

The breakdown of how these different forms of curtailment reduced generation across the LSS Round Projects is shown in Figure 5. Periods of curtailment that were not clearly due to either a dispatch constraint or a negative pricing event have been categorised as other curtailment. It is understood that most of this curtailment was induced at AEMO's direction but facilitated outside of the NEMDE. More information on this breakdown and calculations can be found in the Appendix: Metric Calculation Methodologies.

The average amount of energy lost to curtailment across 2019 and 2020 for the LSS Round Projects is 5.1 per cent, where one project lost 18.8 per cent of generation in total. In 2019, one project was curtailed more than 23.4 per cent.

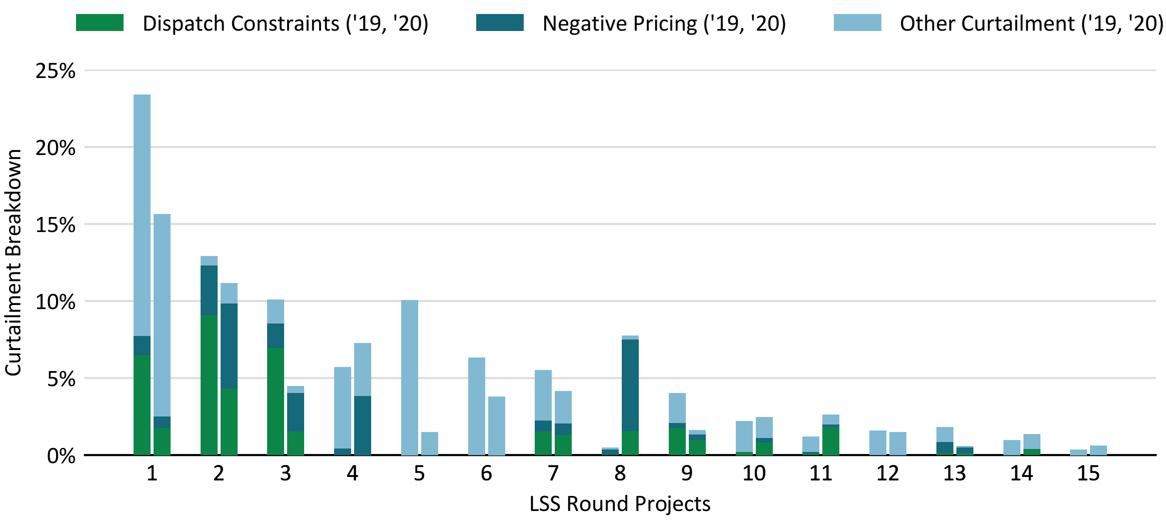

Figure 5. Curtailment breakdown across the LSS Round Projects.

UNEXPECTED CURTAILMENT

The risk of poor system strength in a region neighbouring one of the LSS Round Projects resulted in AEMO applying constraints to a significantly higher amount of dispatch intervals and while it is not certain how this will impact the project into the future, the sponsor expects the curtailment to continue.

Across 2019 and 2020, dispatch constraints, negative pricing and other curtailment were responsible for approximately 54 GWh, 35 GWh and 79 GWh of lost generation respectively across the entire portfolio. On a project level, dispatch constraints, negative pricing and other curtailment resulted in, on average, curtailment of 1.3 per cent, 1.1 per cent and 2.8 per cent respectively. Other curtailment accounted for 14.2 per cent curtailment on one project across 2019 and 2020. Constraints applied outside the NEMDE system resulted in one project being curtailed 15.7 per cent in 2019. Three projects located in Queensland self-curtailed over 3 per cent of generation in 2020 due to negative pricing.

6 Curtailment of solar farms through binding constraints via the NEMDE system [6].

7 Periods where the output of the solar farm was self-curtailed to avoid the costs of negative price events.

8 Losses experienced by the solar farm due to limits on the capacity of the farm at the inverter level.

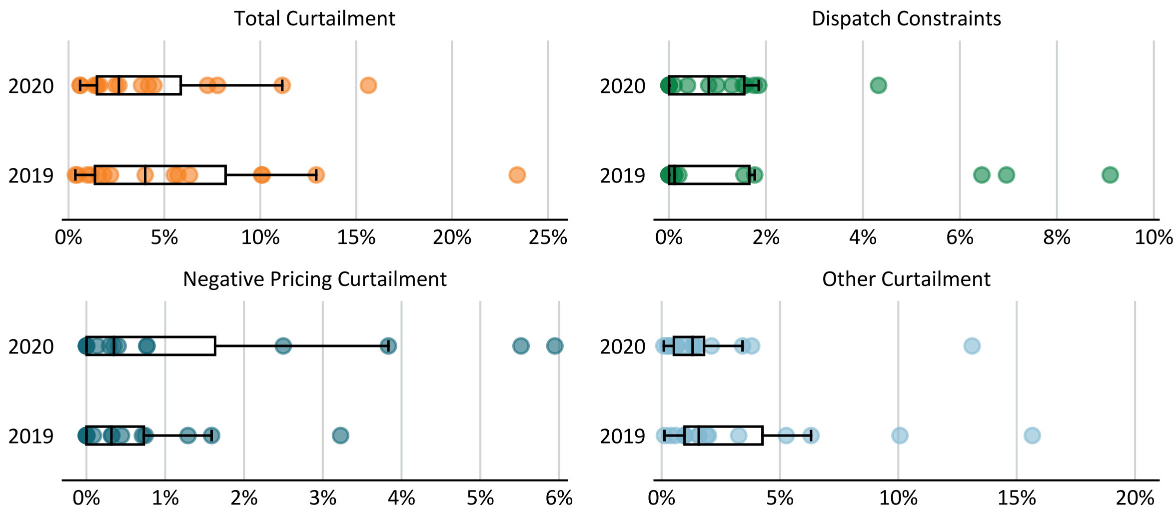

Figure 6. Constraint breakdown box plots for the LSS Round Projects.

The results of the curtailment breakdown analysis indicate that curtailment from dispatch constraints and plant derating were disproportionately distributed across the portfolio, reflecting the way that these constraints are applied in response to local grid conditions. Negative pricing impacts, however, increased significantly for many projects in 2020, specifically for those located in Queensland.

ANATOMY OF A SYSTEM STRENGTH RESOLUTION

In April 2020, AEMO declared a system strength shortfall in North Queensland. As a result, system normal constraint equations were developed for inverter-based generation in the area which meant that, depending on the level of synchronous generation in the network in particular areas, energy export for certain LSS Round Projects (i.e. Collinsville, Hamilton, Kidston, Longreach and Whitsunday) was curtailed by AEMO. This presents an unforeseen challenge that has limited avenues for mitigation. Projects not contributing directly to the issue are solely reliant on the network operator to implement measures to permanently resolve the issue. The system strength shortfall is not due to be resolved until August 2021.

The nature and magnitude of the impact of curtailment on large scale solar projects is evolving over time as the network adjusts to accommodate the increasing amount of energy generated by renewables. This is illustrated clearly in Figure 7 below. While negative pricing losses increased across the LSS Round Projects in the latter part of 2020, the overall curtailment reduced. However, as Figure 8 shows, these impacts are very concentrated at specific projects, with the median percentage losses due to curtailment remaining below 3.3 per cent per month across 2019 and 2020.

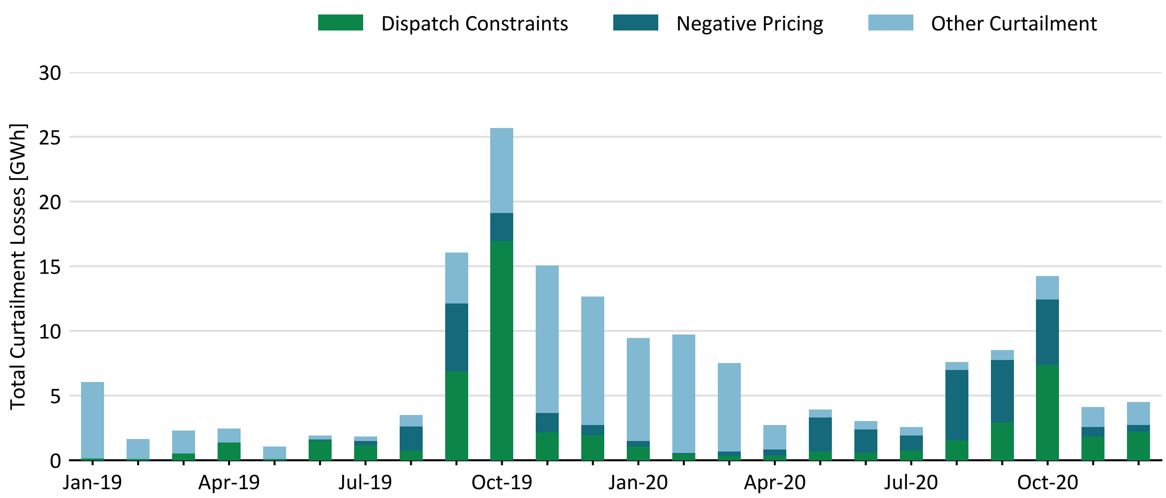

Figure 7. Total losses due to curtailment across LSS Round Projects by month.

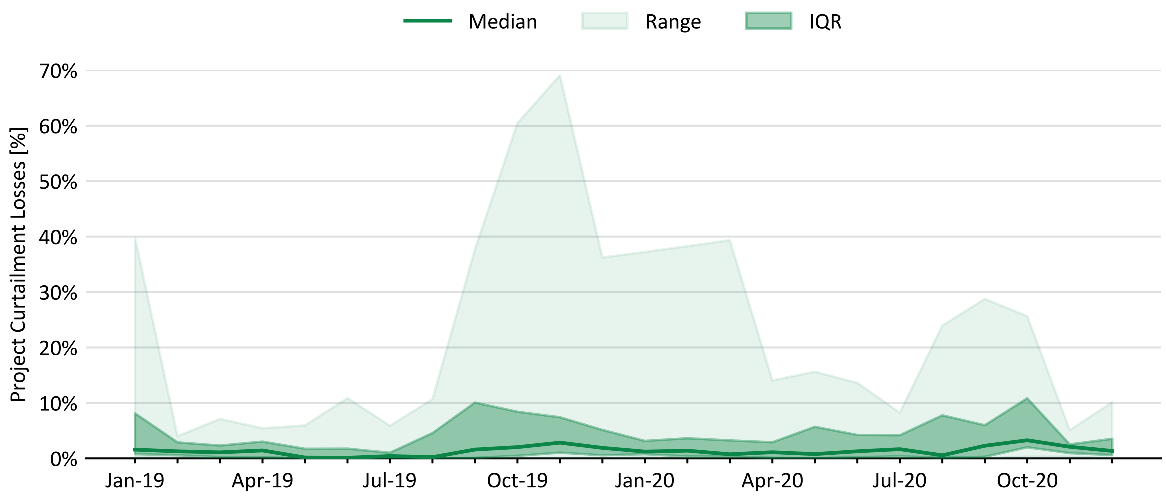

Figure 8. Median, range and interquartile range (IQR) of percentage losses due to curtailment across LSS Round Projects by month.

1.3 CAPACITY FACTOR – THE LSS ROUND PROJECTS

Each LSS Round Project forecast the first year and 25-year capacity factors at financial close. On average across the portfolio, forecasts at the time of ARENA submission indicated that proponents expected a 25-year capacity factor to be 1.5 per cent less than the capacity factor in the first year of operation. Figure 9 compares the forecast capacity factor (for the first year of generation) with what occurred in 2019 and 2020. Capacity factor forecasts for the first year of operation ranged from 23.2 per cent to 33.1 per cent. Actual capacity factors achieved in 2019 and 2020 ranged from 16.9 per cent to 29.0 per cent and 19.6 per cent to 28.6 per cent respectively.

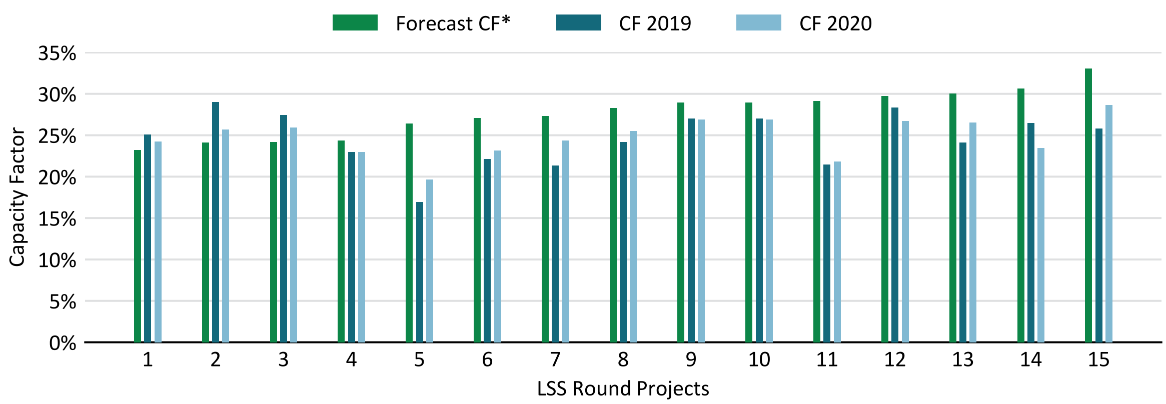

Figure 9. Actual vs. forecast capacity factors bar chart. *The Forecast CF is the forecast for the first year of generation.

Figure 10 shows that LSS Round Projects expected to achieve capacity factors that were, on average, 11.0 per cent higher than what was achieved in their first year of operation. One project overestimated capacity factor in the first year by 35.9 per cent, while another underestimated capacity factor by 20.5 per cent. More than a third of the LSS Round Projects overestimated capacity factor in the first year of generation by approximately 20 per cent.

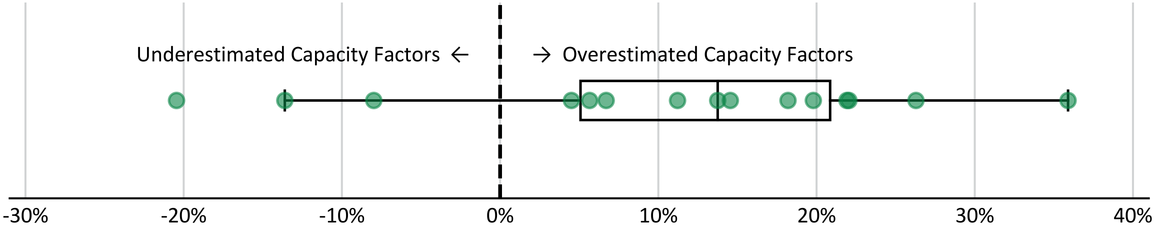

Figure 10. Forecast vs. actual capacity factors for the first year of operation.

The capacity factor provides a method for comparing the total yield – and hence profitability – across the different sized projects in the portfolio. The significant overestimation of the capacity factor for most projects across the portfolio highlights the impact on investment returns as a consequence of the performance and curtailment discussed above.

SECTION TWO: OPERATIONAL EXPENDITURE, MAJOR OPERATIONAL CHALLENGES, AND REVENUE

This section explores how operational expenditure, major operational challenges and revenue compare across projects, while reflecting on what was forecast for these metrics at the time of financial close. The CEFC has supplemented this information with commentary drawn from the experience of the Post-LSS Round Projects.

2.1 OPERATIONAL EXPENDITURE – THE LSS ROUND PROJECTS

Figure 11 compares the forecast (at final ARENA grant submission for the first year of operation) and actual annual operational expenditure (OPEX) in 2020 for each of the LSS Round Projects. Project numbers are selected randomly for the purpose of anonymity. The OPEX is displayed visually using a vertical bar chart, where the respective forecast OPEX is displayed using a horizontal black line. Across the 11 projects, OPEX in 2020 was forecast to range from $12,000 to $34,000 per MW_{DC} of installed capacity. The average OPEX forecast across the 11 projects was $22,500 per MW_{DC}. Actual OPEX in 2020 ranged from $13,500 to $42,500 per MW_{DC}. The average actual OPEX in 2020 was $30,000 per MW_{DC}.

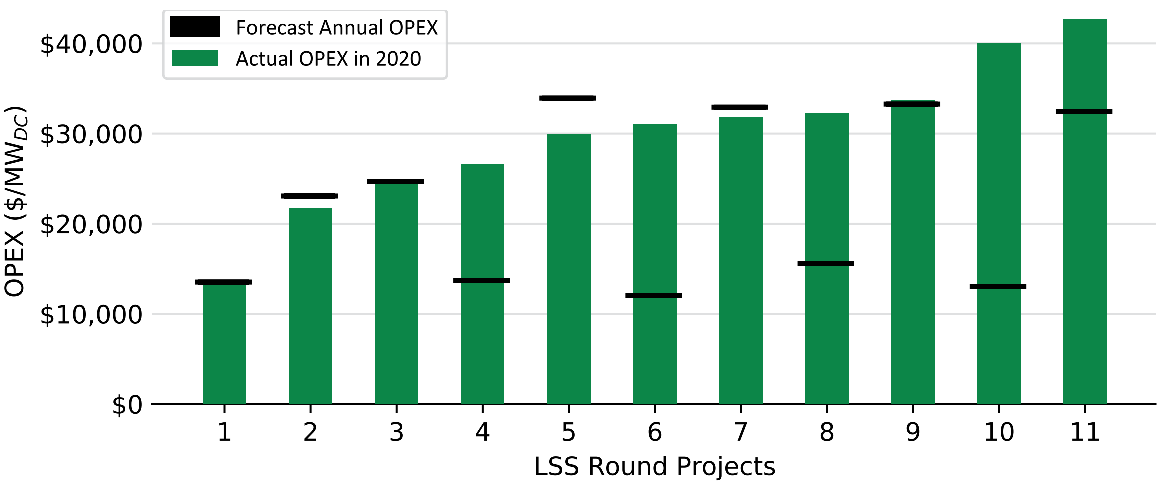

Figure 11. Bar chart showing actual OPEX in 2020 for 11 of the LSS Round Projects. The respective forecast OPEX for each project is displayed by a horizontal black line.

From the sample, no clear relationship emerged between the size of the project and operational expenditure per MW_{DC}. On average, projects with fixed-tilt arrays tended to have lower operational expenditure than those with tracking arrays, however, even in the small sample size there were exceptions to this trend.

Boxplots in Figure 12 describe statistics on how actual OPEX values compared to what was forecast for 2020 across the portfolio. Across 11 data points, on average, actual OPEX in 2020 exceeded forecasts by $6,000 per MW_{DC}. With respect to forecasts, one project spent $4,000 per MW_{DC} less on OPEX, while another project spent $27,000 per MW_{DC} more. Seven projects underestimated OPEX in 2020, while four projects overestimated.

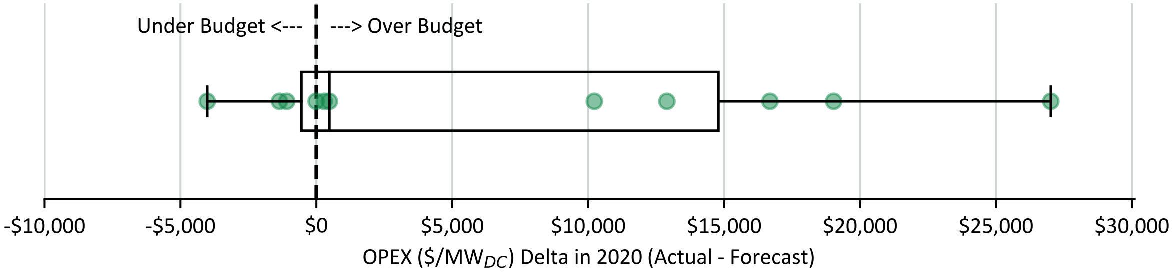

Figure 12. Boxplot showing the difference between actual and forecast OPEX in 2020 for 11 of the LSS Round Projects

All projects were asked to identify the top five items contributing to OPEX. O&M, FCAS, land lease, grid connection, insurance and asset management were most commonly reported and contributed significantly to total OPEX. These categories have been used when comparing OPEX across the LSS Round Projects as shown in Figure 13. The remaining OPEX items identified by the projects have been grouped into the "other" category as only a small number of projects each identified them as contributors to OPEX. These items include:

- Satellite, bidding, IT, settlement services, metering, corporate allocation, imported electricity, transmission, property, consultants and legal, royalties, accounting, auditing, tax, defect rectifications, travel, materials, equipment, community, site works, biodiversity offset allowance, and other unidentifiable items reported by projects.

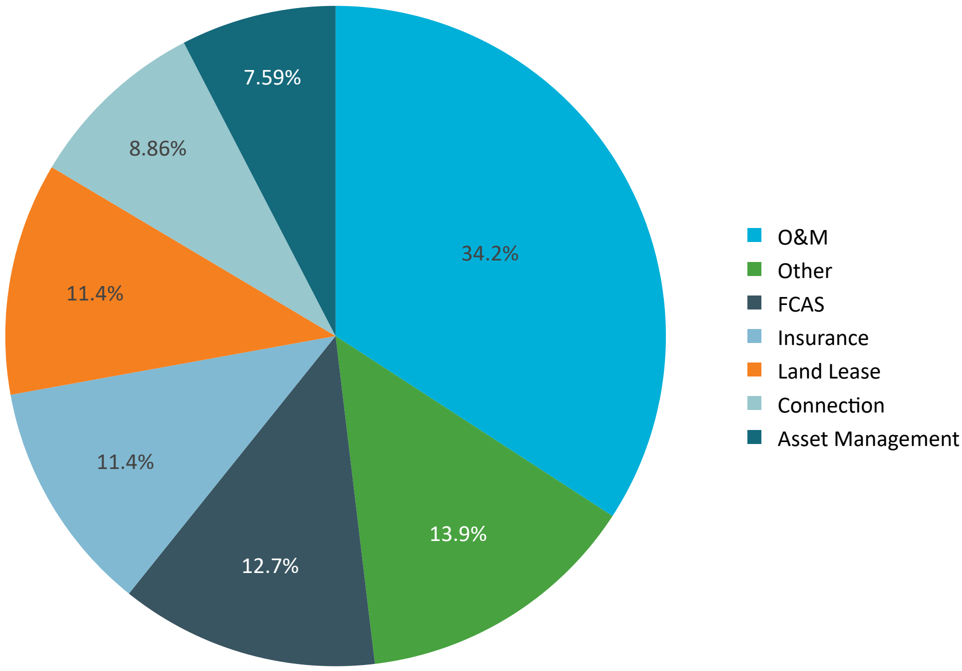

Figure 13. Average contribution to total OPEX for different items reported on by the LSS Round Projects

The large number of items grouped into the "Other" category results in a large spread in this item's contribution to the total OPEX, ranging from $500 to $17,500 per MW$_{DC}$. This range is clearly represented in the boxplots in Figure 14 which compare the breakdown of OPEX items.

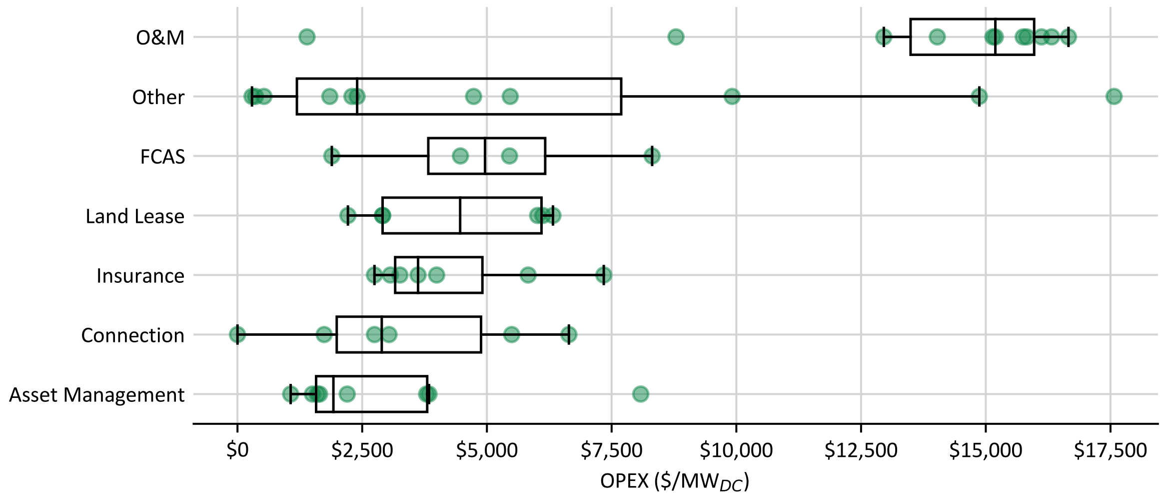

Figure 14. Boxplots showing the breakdown of OPEX items

Of the four projects reporting significant FCAS costs, FCAS costs were on average approximately 64 per cent higher in 2019 compared with 2020. The following points may explain some of the difference:

- Several solar farms have been registered for self-forecasting with AEMO since late 2019, which generally improves the Causer-Pays factor for FCAS costs compared to using Australian Solar Energy Forecasting System (ASEFS) forecasts.
- Electricity market prices have generally been depressed since the impact of COVID-19 began in March 2020, and hence so has the cost to recover Causer-Pays FCAS costs.
- The high FCAS prices in Jan 2020 were due to a market event (islanding of the SA grid) which sent FCAS prices high across the market.

TRENDS IN THE SOLAR INSURANCE MARKETS

Project sponsors have also generally experienced an increase in insurance premiums versus what may have been expected at financial close. This reflects: a general tightening of the global insurance market; and insurance companies responding to particular risks experienced since the projects were built, including significant storm/wind events which have damaged solar farms, and the unprecedented 2019 bushfires which burned through much of Australia including the some of the regions in which solar farms were located.

2.2 MAJOR OPERATIONAL CHALLENGES – THE LSS ROUND PROJECTS

The proponents of the LSS Round Projects were asked to identify their top five major operational challenges experienced across the first two years of operation. There are many operational challenges that significantly impact projects but quantifying this impact is difficult (e.g. COVID-19, rule changes, lack of vendor support etc.) and it is important that industry is aware of what some of these major challenges have been for the LSS Round Projects. Figure 15 summarises this aggregated information showing overall trends in the top industry challenges.

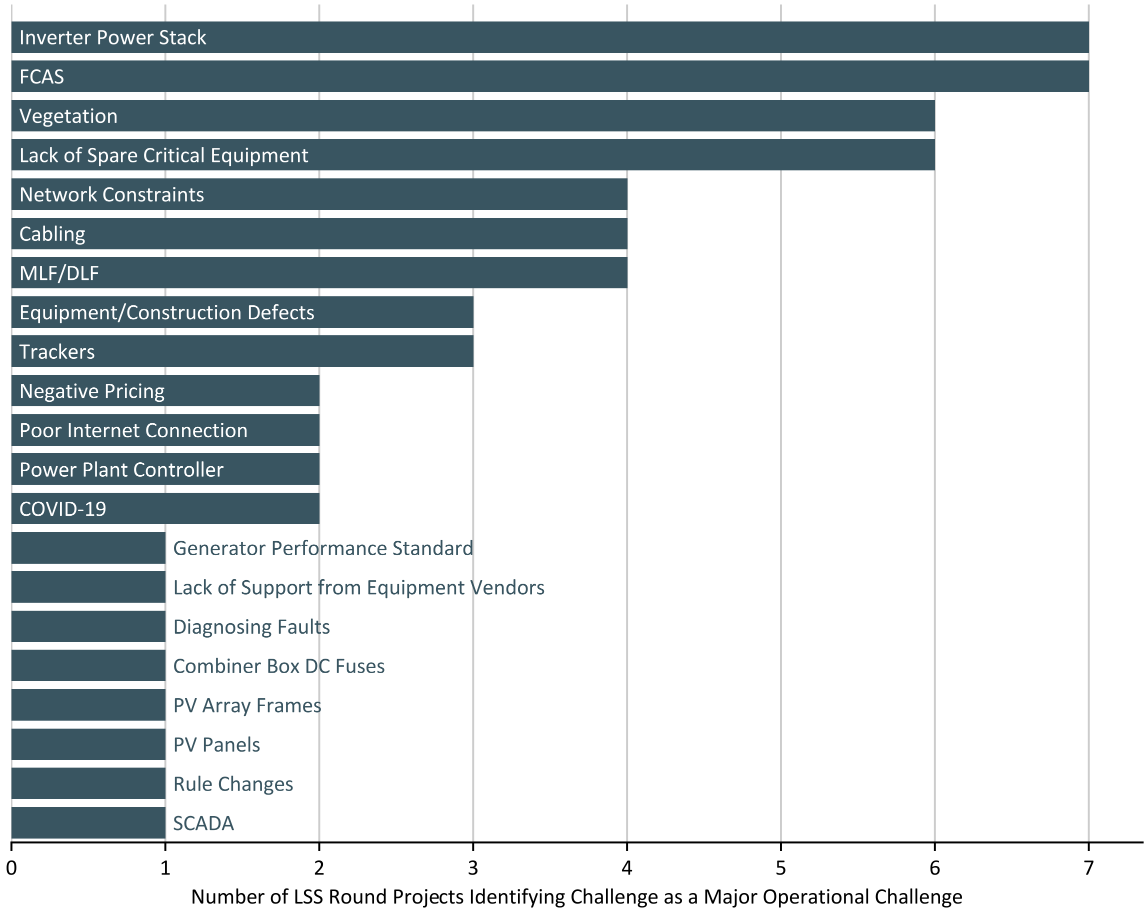

Figure 15. Major operational challenges experienced over the first two years of operations by the LSS Round Projects

Figure 15 demonstrates that some of the most impactful challenges identified across the LSS Round Projects were FCAS, inverter power stack failures, vegetation control and lack of spare critical equipment.

WHAT IS FCAS AND WHY ARE THE FCAS COSTS TO SOLAR FARMS SO VARIABLE?

Frequency control ancillary service (FCAS) charges were higher than expected due to generation forecasts (provided either by the self-forecasting from the generator or the ASEFS) being different to actual generation.

FCAS refers to frequency control ancillary services, which are services procured by grid operators to maintain the grid frequency level within defined bands to keep the grid secure. Historically FCAS services have been provided by gas and hydro generators, but more recently battery storage projects have been participating to sell services into this market. Individual renewables generators are charged a portion of the overall grid FCAS costs on a "causer pays" basis, if the difference between the amount of power that AEMO expected a generator to deliver differs from what was actually delivered (and as a result FCAS services would have needed to be procured). This volume difference can be exacerbated: during the commissioning process a project's generation is being ramped up and down to meet certain commissioning tests; and/or if the weather data that AEMO uses to calculate the expected generation from a particular solar farm differs from the actual cloud cover conditions at site.

The FCAS market has historically been volatile, with high market prices soaring in late 2019/early 2020 in part due to islanding events particularly in South Australia. Solar farms who generated at a different level to what AEMO was expecting via ASEFS would have borne these higher costs. Since then, the FCAS market has softened and is forecast to reduce further still as more battery storage is incorporated into the system.

A number of individual solar farms have implemented "self-forecasting" with AEMO where the individual generator provides real time generation forecasts based on actual site conditions with the assistance of satellite or cloud cam technology. CEFC observes that the sponsors of their solar farms participating in self-forecasting have experienced reduced FCAS costs versus the ASEFS baseline.

Longreach Solar Farm

LOCAL ENVIRONMENTAL IMPACTS

Vegetation control can include both fire mitigation (fire breaks, fuel source, etc.) and height management to minimize impact on site assets and their performance (shading, etc.). It is a high cost and resource intensive activity. Some projects have sheep located on site which have proven beneficial from both a community engagement and vegetation management (during low to medium growth periods) perspective. Some issues are becoming evident that require strategy and plan improvements:

1. Inconsistent sheep grazing – introduction of internal site fencing allowing the use of zones to get more even grazing and benefits.
2. Management of fire risk mitigation – mapping and assessment of areas where herbicide use is required to achieve the risk mitigation strategies.
3. Variability in seasonal and annual vegetation growth – the difference between drought conditions each year led to the development of more robust management plans being required, which include the use of herbicide to manage weeds, mowing augmentation and scalable resourcing.
4. Resourcing – in-house mower and resourcing have been added to some teams to provide a baseline capability.

EQUIPMENT AVAILABILITY

Lack of spare critical equipment resulted in some projects relying on overseas factories to supply and ship spare equipment which caused lengthy downtimes on projects. For example, on some projects the inverter supplier has no inverter, transformer, or ring main unit in stock in Australia. Further, equipment service providers do not always have sufficient employees or sub-contractors to effectively service new sites. There is also an inherent reliance on equipment service provider technicians. The range of services that can be located on site and available on short notice is very limited. Even with accredited training, equipment service providers are reluctant to approve any in-house maintenance except the most basic fault finding and rectification. This leads to almost complete monopoly and reliance on the equipment manufacturer. Good relationships with suppliers have proven extremely important to help mitigate the overall impact on assets. Some projects have implemented and continue to implement the following actions:

1. More direct engagement with the local and parent service providers. This has led to proponents supporting and promoting greater service levels and spares inventories in Australia.
2. Lessons learned being distributed internally for consideration for new projects and contractual agreements.
3. Acquisition of own critical major spares.

2.3 REVENUE – THE LSS ROUND PROJECTS

The following section does not discuss revenue obtained through Power Purchase Agreements, which most projects have established. Details of PPAs are confidential and not for public disclosure. As a result, this study looks at what revenue was generated through the spot market and adjusted for marginal loss factors (disregarding any hedging the projects may have in place through PPAs). All generators receive payments via AEMO at the spot price for all generation in the relevant region. Under a PPA for electricity supply, typically if the spot price received by the project is lower than the PPA strike price, the PPA will top up the project for the difference. If the spot price is higher, generally the project will pay to the PPA offtaker the difference, this means that ultimately the project receives a net fixed price for the contracted portion of its generation and is therefore less exposed to the spot price. Given the timing of the ARENA tender round, it is reasonable to expect that the offtake agreements entered into would have been priced at a level reflecting the higher market and LGC price forecasts at the time versus the lower prices experienced in 2019 and 2020. Utility solar was such a small part of the overall energy mix and the Renewable Energy Target seemed almost unachievable at the time the grant round was run, so solar projects at that time were attracting higher PPA prices than have been achievable in recent years given the proliferation of solar generation (utility and rooftop) in the interim.

The top image in Figure 16 shows how the average daily spot price profile changed from 2019 to 2020 on the NEM. The values shown are the weighted average across all states on the NEM weighted by the total demand at each dispatch interval.

Assuming that daylight hours are between 6am and 6pm, the average 5-minute trading interval spot price during daylight hours (noting that settlement occurs over 30-minute intervals) is 35 per cent lower in 2020 than in 2019. The average spot price across all daylight hours fell from $102 per MWh in 2019 to $66 per MWh in 2020. This will be further explored in subsequent reports in this series. The average spot price across all hours was $93 per MWh in 2019 and $56 per MWh in 2020. By contrast, at the end of 2018, EY forecast the average spot price across the NEM to be $83 per MWh in 2019 and $70 in 2020 [11]. CEFC notes that observed spot prices in 2021 to date have been even lower, with forecasters generally ascribing a price recovery over time as commodity prices increase and as coal fired generation exits the system.

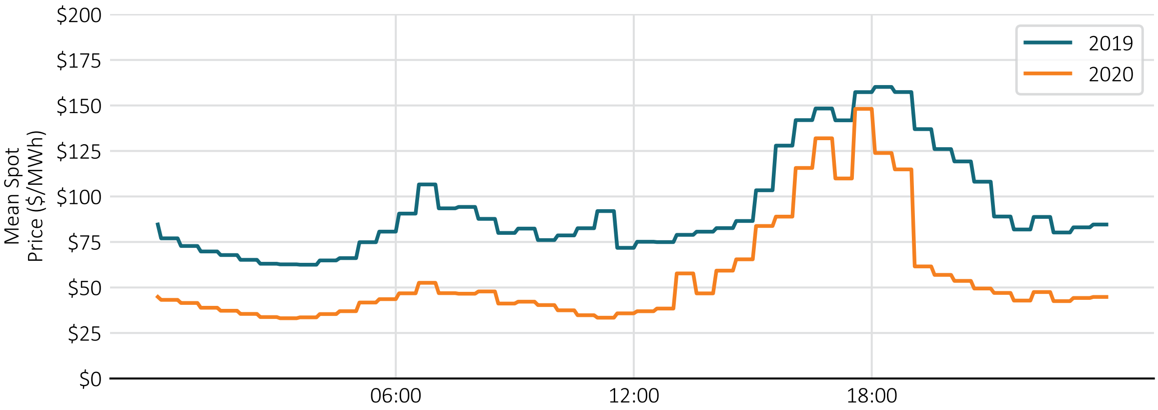

Figure 16. Daily 5-minute spot price profile in 2019 and 2020, weighted average across states by total demand.

Figure 17 shows the annual revenue across the LSS Round Projects at the spot market price. The revenue is normalized by project size in terms of installed DC capacity (MW). This is a preferable metric in comparing revenue among large scale solar projects rather than capacity factor or average annual spot price as it accounts for the hourly variation in price and its relationship with the times at which solar generation is at a maximum. This captures the extent to which 'the energy was valuable when generated' [12]. The revenue at each dispatch interval is the product of the spot price, energy generated and the marginal loss factor for the relevant project during the dispatch interval.

Figure 17 shows that in 2019, the revenue across the LSS Round Projects ranged from $74,150 to $212,335 per MW_{DC} of installed capacity, where the average was $129,646 per MW_{DC}. In 2020, the revenue across the LSS Round Projects ranged from $35,953 to $139,022 per MW_{DC} of installed capacity (i.e. the project with the highest revenue per unit of capacity received over 3x as much the project with the lowest), while the average was $79,640 per MW_{DC}. Continuing with this metric, across the LSS Round Projects revenue in 2020 was down from 2019, on average, by 39 per cent. One project's revenue per MW_{DC} fell by 73 per cent, or $154,135 per MW_{DC}.

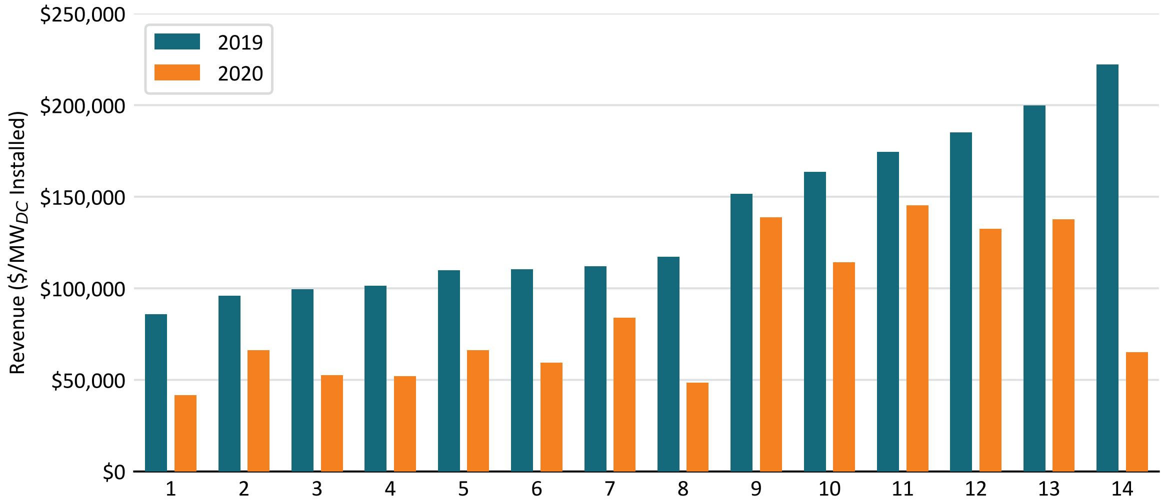

Figure 17. Revenue per MW DC installed in 2019 and 2020 for each of the LSS Round Projects

The primary cause of the lower spot market revenues in 2020 versus 2019 is the fall in the average spot market price from 2019 to 2020. As the figure below shows, annual project revenue per MW_{DC} is closely correlated with the volume-weighted average spot price per MWh received by the project over the course of the year. For the project with the greatest fall in revenue, curtailment and a significantly reduced marginal loss factor also contributed.

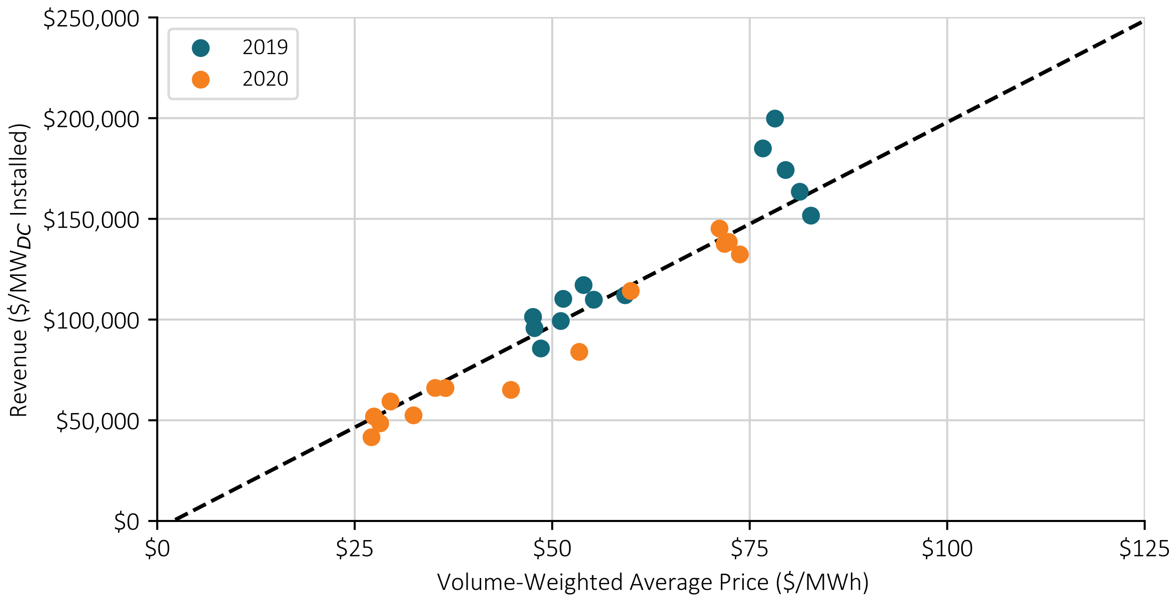

Figure 18. Annual Revenue per MW_{DC} versus Volume-Weighted Average Price, with line of best fit

This report has highlighted some useful aspects of how the first LSS projects have been performing. It has also identified a number of challenges that were not anticipated, or at least not to the extent identified here.

ARENA and CEFC are working closely with market participants to understand the challenges and opportunities to support key initiatives.

The next study in the ARENA's Generator Operations series will explore Ramp Rates for Solar and Wind generators on the NEM.

DEFINITIONS

Performance Ratio (PR) is a measure of overall plant efficiency[9]. The PR measures the impact of all losses experienced by the system from the sunlight reaching the modules to energy export to the grid, including module degradation, reflectance, temperature losses, inverter efficiency, and all other balance of system component inefficiencies [3]. Engineering, procurement, and construction (EPC) contracts for PV projects typically stipulate liquidated damages based on a PR guarantee value, with the plant being expected to perform at or above this PR value over a pre-agreed period of operation following practical completion. The PR guarantee is then compared to actual plant PR to determine any recoverable damages. As there are many external and uncontrollable factors that impact PR (including, for example, where a plant is required to reduce its generation for grid stability reasons), the operational data that is included and/or excluded from the PR assessment is often determined on a bespoke basis [4].

Under the terms of the contract, the EPC contractor may be required to pay performance liquidated damages (PLDs) equivalent to the value of the energy forgone by the owner due to the failure to achieve the agreed plant performance. If a performance shortfall is unable to be rectified, the EPC contractor may be required to pay lifetime PLDs equivalent to the total value of all future foregone revenue. This study does not break down the PR in this detail, nor determine whether poor performance is attributable to the EPC contractors. Information on the calculation of PR values reported in this study can be found in the Appendix.

Curtailment describes any period where the output from a generator is reduced from the maximum that could have been generated in the prevailing weather conditions. In 2016 when the LSS Round Projects were completing their applications, curtailment was rarely discussed and not considered a major risk to large-scale solar investments. Today, AEMO's Quarterly Energy Dynamic (QED) reports devote entire sections to summarising curtailment for readers as it is now considered a major risk to investments. Quantifying, understanding, and forecasting curtailment on generators is now an essential consideration for asset valuation. Some of the key causes for curtailment include commissioning (i.e. the ability of inverters to pass through hold points – see *Insights from the First Wave of Large-Scale Solar Projects in Australia*), network constraints (e.g., thermal constraints, local system strength requirements such as contingency, oscillations, harmonics), and economics (e.g., when the generator reduces its offer in order to avoid negative pricing events).

Capacity factor (CF) is the ratio between the energy a generator produces and the energy that would have been produced if the generator operated at maximum capacity at all time intervals, and it is widely used to compare the overall performance, after considering all losses, of different generation technologies. However, it also standardises the total annual energy yield of a solar generator which enables the comparison of arrays of different capacities and the annual yield of generators over time. Comparing this metric across the portfolio and against what was forecast provides a valuable benchmark for industry.

9 It is calculated as the ratio of the energy generated with respect to the energy that would have been generated if the system operated continuously at the rated efficiency of the modules at nominal standard test conditions (STC) [2].

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APPENDIX: METRIC CALCULATION METHODOLOGIES

This Appendix defines in detail the key metrics referred to in this report and, where applicable, provides the formulas and methodologies used in their calculation.

UNCORRECTED PERFORMANCE RATIO

Definition: The ratio of the energy generated by the solar farm with respect to the energy that would have been generated if the system was continuously operated at the rated efficiency of the modules at nominal standard test conditions (STC). The formula for the Uncorrected Performance Ratio (PR) is shown in Equation 1.

Equation 1: Uncorrected PR

$$PR = \frac{Y_f}{Y_{ref}} = \frac{\sum_k P_{out,k} \times \tau_k}{\sum_k P_{STC}\left(\frac{G_{POA,k}}{G_{STC}}\right) \times \tau_k}$$

Where:

- Y_f: Actual Energy Yield over the measurement period [MWh]
- Y_{ref}: Reference Energy Yield over the measurement period [MWh]
- PR: Uncorrected Performance Ratio [unitless]
- $P_{out,k}$: Measured AC power output of the array at interval k [MW]
- P_{STC}: Array DC power rating; the total DC power output of all installed PV modules at STC [MW]
- $G_{POA,k}$: Measured plane of array (POA) irradiance at interval k [W/m^2]
- G_{STC}: Irradiance at standard test conditions [1,000 W/m^2]
- k: A given recording interval
- τ_k: The length of the recording interval k; in this study 5 minute intervals have been used [h]

For each Project, the Uncorrected PR was only calculated in periods where measured data was available for $P_{out,k}$ and $G_{POA,k}$ Further, overnight energy consumption and periods prior to full generation were excluded. The Uncorrected PR for each Project is shown in Figure 2.

MODELLED OUTPUT

Definition: The estimated AC power output of the solar farm calculated from a regression model (outlined below) in periods where the farm was constrained, derated or unavailable.

To model the output of the solar farm, an ordinary linear regression model was developed on a training dataset taken from the 2019 and 2020 data provided by each Project.

The training dataset was selected to satisfy the following conditions:

- Temperature-corrected PR between 70 per cent and 100 per cent (normal operating range).
- No active constraints (ie, SEMIDISPATCHCAP not equal to zero).
- Non-null measurements for $P_{out,k}$, $G_{POA,k}$ and $T_{mod,k}$
- Exclusion of periods where a known number of inverters were offline (eg, Gannawarra SF from October 2019 to March 2020).
- Exclusion of periods where $P_{out,k}$ is between 5 per cent and 95 per cent of the AC rated capacity.

The model used is outlined in Equation 2.

Equation 2: Modelled Output

$$P_{MODEL,k} = \beta_1 G_{POA,k} + \beta_2 G_{POA,k} T_{mod,k}$$

$$Y_{MODEL} = \sum_k P_{MODEL,k} \times \tau_k$$

Where:

- $P_{MODEL,k}$: Estimated AC power output of the array at interval k [MW]
- β_1, β_2: Regression coefficients
- Y_{MODEL}: Estimated yield over a given period based on modelled AC power output [MWh]

This model was selected after trialling a number of combinations of weather and other variables as exogenous variables. For all projects, the model achieved adjusted R2 values greater than 0.925 and Root Mean Squared Percentage Error (RMSPE) values less than 1 per cent.

q**Definition:** Losses experienced by the solar farm due to site downtime or site outages.

Site downtime (unavailability) was identified as periods satisfying the following conditions:

- $P_{out,k}$ equal to 0 MW.
- $P_{out,k}$ was greater than 100 W/m^2.
- No active constraints (ie, SEMIDISPATCHCAP not equal to zero).
- No negative price event.

The losses due to site downtime, $L_{UNAVAILABILITY}$, were calculated as equal to Y_{MODEL} for all periods satisfying the conditions for unavailability. The percentage losses due to unavailability are calculated from the ratio of $L_{UNAVAILABILITY}$ to Y_ref. Unavailability Losses [%] for each Project are represented by the 'Unavailability' bar in Figure 2.

DISPATCH CONSTRAINTS LOSSES [%]

Definition: Curtailment of solar farms through binding constraints via the NEMDE system.

Constrained periods can be identified using public dispatch data from AEMO's NEMWEB [6]. AEMO constraints are deemed to be curtailing a solar farm in periods satisfying the following conditions:

- The SEMIDISPATCHCAP flag for the solar farm in the DISPATCHLOAD table is set to 1. This indicates that the output of the solar farm must not exceed the TOTALCLEARED value from the DISPATCHLOAD table [7].
- One or more constraints are recorded in the DISPATCHCONSTRAINT table for the given period with a MARGINALVALUE not equal to 0.
- No negative price event.

Total estimated losses due to AEMO constraints, $L_{DISPATCH\_CONSTRAINTS}$, are calculated in two ways:

- Where the TOTALCLEARED[10] was less than the AVAILABILITY,[11] losses were estimated based on the difference between AVAILABILITY and TOTALCLEARED.
- Where TOTALCLEARED was equal to AVAILABILITY, but the SEMIDISPATCHCAP was set to 1, losses were estimated as Y_{MODEL}- Y_f. It was assumed that in these periods AEMO had revised the AVAILABILITY to match the constraint requirements (or the farm's self-forecasting was revised downwards to match the constraint).

The percentage losses due to dispatch constraints are calculated from the ratio of $L_{DISPATCH\_CONSTRAINTS}$ to Y_{ref}. Dispatch Constraints Losses [%] for each Project are represented by the 'Dispatch Constraints' bar in Figure 5.

10 AEMO's TOTALCLEARED is the target generation in each dispatch interval for both scheduled and semi-scheduled generators [8].

11 AEMO's AVAILABILITY is the amount of generation from each generator deemed available in each dispatch interval, provided either by the self-forecasting from the generator or the Australian Solar Energy Forecasting System (ASEFS) [9].

OTHER CURTAILMENT LOSSES [%]

Definition: Losses experienced by the solar farm due to limits on the capacity of the farm at the inverter level, which have been applied when:

- A direction from AEMO or the Distribution Network Service Provider (DNSP), operating outside the National Electricity Market Dispatch Engine (NEMDE), requires that inverters be taken offline or the inverters be operated at less than their rated capacity; or
- Due to faults with an inverter / inverter stack, the total farm capacity is reduced for a time.

This also includes constraints where capacity is capped in real time based on a function of current weather conditions.

Other curtailment is deemed to apply in periods satisfying the following conditions:

- No active constraints (ie, SEMIDISPATCHCAP not equal to zero).
- Unavailability Losses [%] are equal to 0.
- No negative price event.
- $P_{MODEL,k} - P_{out,k}$ is greater than the typical residuals from the regression model.

In periods where any other curtailment is deemed to apply, the loss, $L_{OTHER\_CURTAILMENT}$, is calculated as equal to $Y_{MODEL} - Y_f$. The percentage losses due to other curtailment are calculated from the ratio of $L_{OTHER\_CURTAILMENT}$ to Y_{ref}. Other Curtailment Losses [%] for each Project are represented by the 'Other Curtailment' bar in Figure 5.

NEGATIVE PRICE EVENT LOSSES [%]

Definition: Periods where the output of the solar farm was self-curtailed to avoid the costs of negative price events.

Losses due to negative price events are deemed to occur in periods where the following conditions are satisfied:

- The regional reference price (RRP) applicable to the given solar farm is less than 0.
- The value for $L_{UNAVAILABILITY}$, $L_{OTHER\_CURTAILMENT}$, or $L_{DISPATCH\_CONSTRAINTS}$ would be non-zero, but for the RRP being less than 0.

The losses due to negative price events, $L_{NEGATIVE\_PRICE\_EVENT}$, are calculated as the value that $L_{UNAVAILABILITY}$, $L_{OTHER\_CURTAILMENT}$, or $L_{DISPATCH\_CONSTRAINTS}$ would have been but for the RRP being less than 0. The percentage losses due to negative price events are calculated from the ratio of $L_{OTHER\_CONSTRAINTS}$ to Y_{ref}. Negative Price Event Losses [%] for each Project are represented by the 'Negative Pricing' bar in Figure 5.

TOTAL CURTAILMENT LOSSES [%]

Definition: Total losses at the solar farm due to Negative Price Events, Dispatch Constraints and Other Curtailment.

The total curtailment losses, $L_{TOTAL\_CURTAILMENT}$, are equal to the sum of $L_{OTHER\_CURTAILMENT}$, $L_{NEGATIVE\_PRICE\_EVENT}$ and $L_{DISPATCH\_CONSTRAINTS}$ for the given solar farm over the relevant period. The total percentage losses due to all forms of curtailment are calculated from the ratio of $L_{TOTAL\_CURTAILMENT}$ to Y_{ref}. Total Curtailment Losses [%] for each Project are represented by the 'Curtailment' bar in Figure 2.

CORRECTED PERFORMANCE RATIO

Definition: The PR adjusted to what the PR would have been had the solar farm not experienced losses as a result of curtailment or unavailability.

The Corrected PR, $PR_{CORRECTED}$, is equal to the sum of the Uncorrected PR, Total Curtailment Losses [%] and Unavailability Losses [%].

TEMPERATURE-CORRECTED PERFORMANCE RATIO

Definition: The PR that the array would have obtained if the modules remained at a constant reference temperature, $T_{mod,ref}$ [2,3]

This correction reduces the seasonal variability of the PR. By using a reference temperature of T_{STC} (ie, 25°C), the Temperature Corrected PR gives the performance of the farm ignoring losses due to temperature. The formula for the Temperature Corrected PR is shown in Equation 3.

Equation 3: Temperature-corrected PR

$$PR_{temp\_corr} = \frac{\sum_k P_{out,k}}{\sum_k P_{STC}\left(\frac{G_{POA,k}}{G_{STC}}\right) \times \left(1 + \frac{\delta}{100}(T_{mod,k} - T_{mod,ref})\right)}$$

Where:

- PR_{temp_corr}: Temperature-corrected performance ratio [unitless]
- $T_{mod,k}$: Average measured module temperature at interval k [°C]
- $T_{mod,ref}$: Constant reference module temperature; in this study $T_{mod,ref}$) = T_{STC} = 25 [°C]
- δ: Temperature coefficient of power corresponding to installed modules [%/°C, negative in sign]

For each Project, the Temperature-corrected PR was only calculated in periods as per the Uncorrected PR, and where measured data was also available for $T_{mod,k}$. This was used as an input to the Modelled Output.

TEMPERATURE LOSSES [%]

Definition: Losses experienced by the solar farm relative to STC conditions due to the module temperature being higher than 25 [°C]. This value also accounts for gains in power output during intervals when the module temperature is below 25 [°C].

The percentage losses due to temperature are calculated using the formula shown in Equation 4.

Equation 4: Temperature Losses [%]

$$Temperature\ Losses\ [\%] = 100\left[1 - \frac{\sum_k P_{STC} \times \left(\frac{G_{POA,k}}{G_{STC}}\right) \times \left(1 + \frac{\delta}{100}(T_{mod,k} - T_{mod,ref})\right)}{\sum_k P_{STC} \times \left(\frac{G_{POA,k}}{G_{STC}}\right)}\right]$$

RESIDUAL LOSSES [%]

Definition: The residual losses explaining the difference between the Corrected PR and an idealised solar farm operating at STC efficiency with no losses (PR = 100%), excluding Temperature Losses. This includes module degradation, soiling, inverter efficiency, wiring losses, and any other losses occurring at the solar farm not accounted for by Temperature Losses, Curtailment or Unavailability.

CAPACITY FACTOR

Definition: The ratio between the energy a generator produces and that which would have been produced if the generator operated at maximum capacity at all time intervals. The formula for the capacity factor is shown in Equation 5.

Equation 5: Capacity Factor

$$CF = \frac{\sum_k P_{out,k} \times \tau_k}{\sum_k P_{MAX\_AC} \times \tau_k}$$

Where:

- CF: Capacity Factor [unitless]
- $P_{out,k}$: Measured AC power output of the array at interval k [MW]
- P_{MAX_AC}: Array AC power rating [MW]
- k: A given recording interval
- τ_k: The length of the recording interval k; in this study 5 minute intervals have been used [h]

Fitting a straight line to the data in Figure 9 demonstrates a relationship existing between geographical footprint and exceedance probabilities for solar and wind normalised ramp rates. For every additional hectare of land (i.e., convex hull) taken up by solar and wind farms, the 0.1 per cent exceedance probability (i.e., the 1 in 1000 probability of exceeding a normalised ramp rate) for four-second normalised ramp rates falls by 0.015 per cent and 0.00017 per cent, respectively. These values change to 0.025 per cent and 0.00092 per cent with respect to five-minute ramp rates for solar and wind generators. The key takeaways from this analysis are:

1. The magnitude of ramp rates at low probabilities of exceedance reduce as geographical footprints of solar and wind farms increase.
2. Increasing the geographical footprint (i.e., hectares of land) has a bigger impact on reducing solar ramp rates than it does compared to reducing wind ramp rates.
3. Increasing the geographical footprint (i.e., hectares of land) of solar and wind farms has a bigger impact reducing low POE ramp rates at lower time resolutions compared to ramp rates measured over shorter periods of time (i.e., 5-minute compared to 4-second).

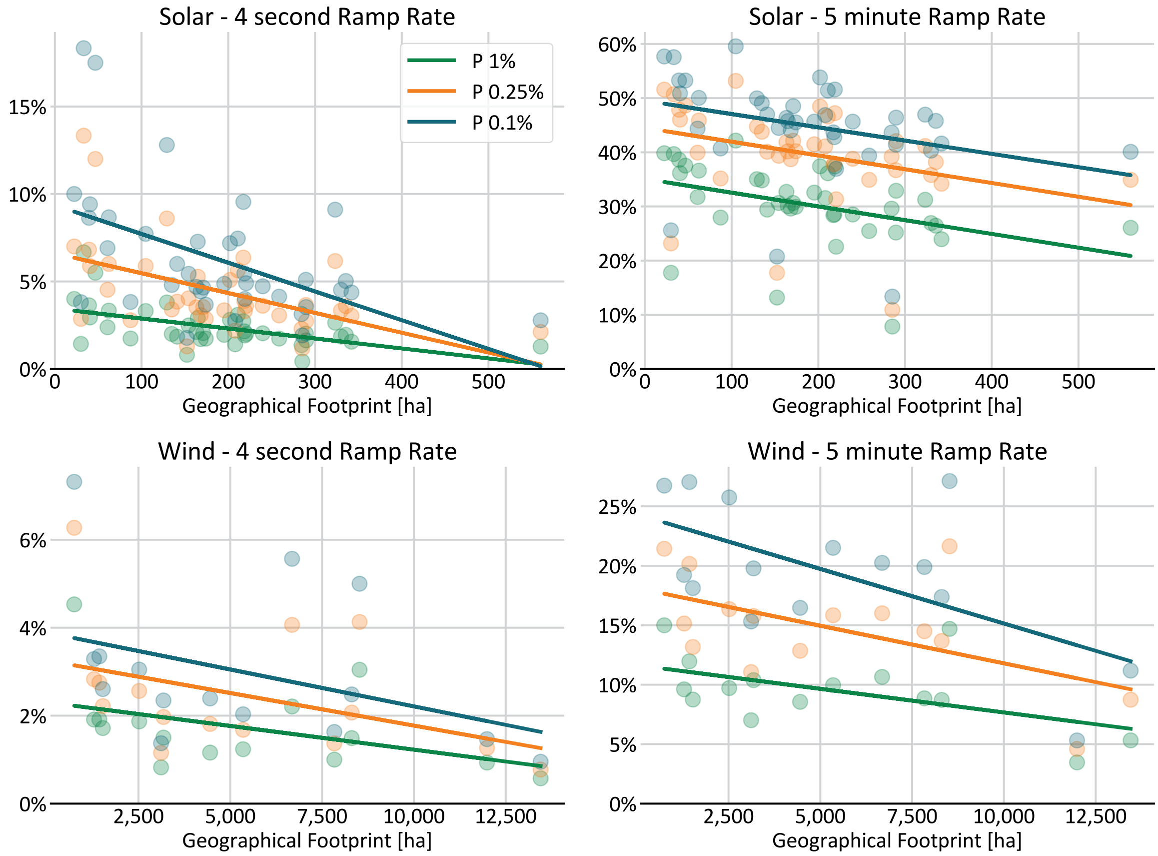

Figure 9. The relationship between normalised ramp rate exceedance probabilities and geographical footprints (convex hull)

The analysis above demonstrates the relationship between farm area and the magnitude of peak ramp rates, which is consistent with the established literature. However, the results also provide the basis for an analysis to determine the significance of area as opposed to capacity for characterising the ramp rate distribution. Figure 10 shows that for both solar and wind farms, the area of the farms is correlated with their registered capacities.

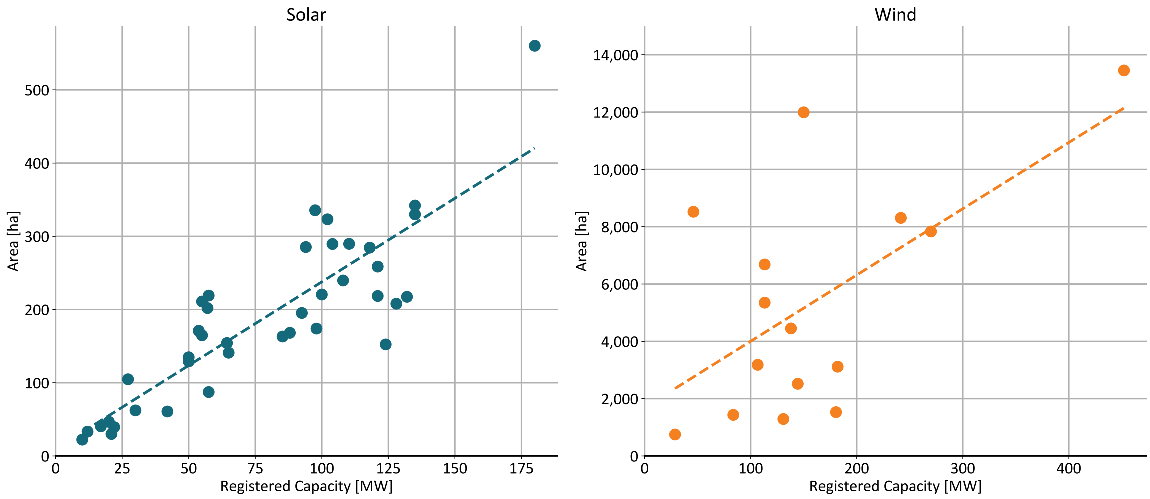

Figure 10. Correlation between registered capacity and area of solar and wind generators with line of best fit

A linear regression analysis was performed of the ramp rate magnitude at 1 per cent, 0.25 per cent and 0.1 per cent probabilities of exceedance against farm capacity, farm area and farm capacity and area. This analysis indicated that models using farm capacity alone performed better than models which used farm area or a combination of area and capacity as independent variables, with performance measured by the leave-one-out cross-validated root-mean-square error and the adjusted-R2 value. This result held for both solar and wind farms at 4-second and 6-second resolution, and at higher temporal resolutions, the performance of the capacity-only and capacity-area combination models was very similar.

While this analysis is based on a relatively small sample size (n=39 for solar, n=15 for wind), it indicates that VRE generator capacity is sufficient to approximate the expected peak ramp rates.

Image: DeGrussa Copper Mine Solar Hybrid Project

SUMMARY

The increased uncertainty in electricity supply due to the rapid growth of solar and wind generators presents challenges for both owners of generators and, when considering the combined impact of ramping, grid operators. This study analyses AEMO's public dispatch data from 2020 at 54 grid-connected variable renewable energy generators to improve the understanding of the relationship that exists between the size of solar and wind generators (i.e., geographical footprint and capacity) and ramp rates. This new empirical analysis conducted on high frequency (i.e., 4 second) datasets assists developers and operators in being able to better optimise the design of hybrid power systems and the appropriate storage, forecasting and other strategies required to best manage variability.

This study presents several new insights on the behaviour of ramp rates at VRE generators:

- It is worth noting that the relationship between normalised ramp rates and capacity will continue to change as technology efficiencies continue to change. The conclusions below reflect analysis conducted on dispatch data in 2020 from 54 VRE generators connected to the NEM. Acknowledging the limitations of the sample size within this study and the fact that not all periods of curtailment[5] were able to be excluded from the analysis, the following rules of thumb can be deduced.
    - The 4-second 0.01 per cent probability of exceedance for solar PV reduces by 0.051 per cent for every additional MW of capacity installed. This value increases to 0.098 per cent when considering the 5-minute 0.01 per cent probability of exceedance ramp rate. The 0.01 per cent probability of exceedance ramp rate for a 10 MW solar generator is approximately 9.76 per cent of installed capacity at 4-second resolution and 51.55 per cent at 5-minute resolution.
    - The 4-second 0.01 per cent probability of exceedance for wind reduces by 0.011 per cent for every additional MW of capacity installed. This value increases to 0.034 per cent when considering the 5-minute 0.01 per cent probability of exceedance ramp rate. The 0.01 per cent probability of exceedance ramp rate for a 10 MW wind generator is approximately 4.65 per cent of installed capacity at 4-second resolution and 24.47 per cent at 5-minute resolution.
- The relationship existing between ramp rates and the size of solar and wind generators has been reported in previous studies, specifically the fact that normalised ramp rates reduce as the size of VRE generators increase. The above rules of thumb confirm these relationships to exist and for the first time, quantify this relationship based on empirical generation and geospatial data collected from a large number of generators. The relationship exists because as the geographical dispersion of an individual VRE generator increases, the renewable resource relied upon is sourced from a larger area. This larger area results in a natural smoothing of resource variability and ultimately results in reducing ramp rates. This study demonstrates that this result remains valid at higher time resolutions of 4-seconds and 6-seconds, as well as at one-minute and 5-minute frequencies.
- Solar generators experience a greater reduction in variability due to geographical dispersion than wind generators. This is made evident by the greater percentage reduction for solar ramp rates vs. wind ramp rates in the rules of thumb above.
- Increasing the geographical footprint of generators has a greater effect on reducing variability over longer time frequencies than shorter time frequencies. The greater percentage reduction for VRE ramp rates at 5-minute intervals vs. 4-second intervals demonstrates this.
- In developing a model for estimating expected ramp rates at 0.1 per cent, 0.25 per cent and 1 per cent probability of exceedance, total generator capacity is an effective proxy for total geographical footprint.

5 Periods where a semi-dispatch cap signal was sent from AEMO and the energy cleared was less than the plant availability at the time (i.e., non weather related curtailment).

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