THE GENERATOR OPERATIONS SERIES

Report Four: Forecasts vs actual from the LSS projects – Solar resource, generation, and spot price

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EXECUTIVE SUMMARY

The Australian Renewable Energy Agency's (ARENA's) $AU100m large-scale solar (LSS) Competitive Round, in collaboration with the Clean Energy Finance Corporation (CEFC), has been an effective mechanism in driving down key cost components of large scale solar in Australia, including the system and financing costs. All LSS projects have now been operating for over two full years and continue to submit confidential data and information through ARENA's Knowledge Sharing Program. This data and information has allowed ARENA and industry to gain valuable insights into aspects of projects that would otherwise remain private.

Financial viability was one of the five key criteria to meet when applying for ARENA's LSS reverse auction in 2016. Detailed financial models submitted to ARENA at the final grant application stage provided estimates on project financial returns that rely on many long-term (i.e., over 25 years) variable forecasts. This paper compares actuals with grant stage forecasts for three key variables that affect project financial viability, including solar resource, generation and revenue. This study reflects on the way each of the project's forecasts compared to what actually happened across 2019 and 2020. The financial models and forecasts referred to were current at the time of final ARENA grant submission, noting these may have been refreshed during the subsequent process through to financial close with the banks.

Most of the projects overestimated observed solar irradiance in 2019 and 2020 by as much as 8 per cent. However, one project understimated it by almost 8 per cent. As a result, six of the ten projects dispatched less energy in 2019 and 2020 than they had forecast[1]. An incorrect forecast of GHI tends to lead to an incorrect forecast of generation and dispatched energy. Inaccurate generation forecasts were, in part, due to the lower than expected GHI, but also the large amount of unexpected curtailment imposed on projects to manage local grid conditions and/or in response to negative electricity pricing.

Figure 1 shows that across 2019 and 2020, forecasts provided by project proponents on the P90 estimates for annual energy dispatched exceeded AEMO's records for the actual energy dispatched (TOTALCLEARED data published by AEMO1) for the 6 projects.

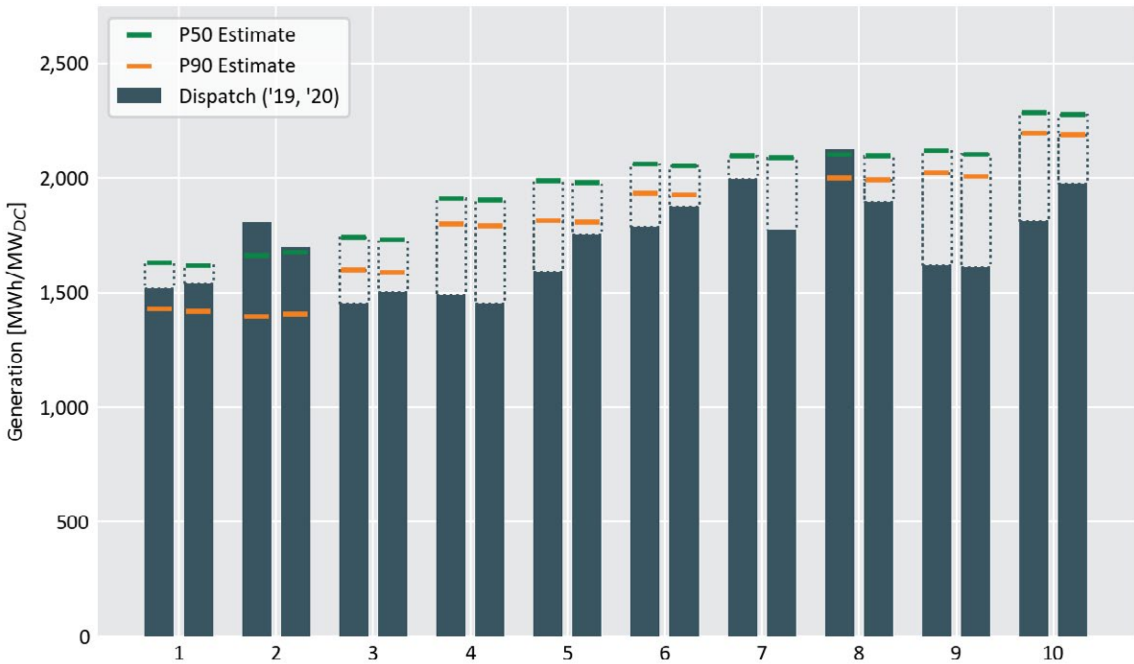

Figure 1. Comparison of AEMO's records for actual energy dispatched (TOTALCLEARED) and estimates for generation across the LSS portfolio for year 2019 and 2020. NB Project 7 did not submit a P90 estimate.

1 Based on the projects' P90 generation estimates (estimates of the output with a 90% probability of exceedance) which are viewed in the industry as conservative.

None of the projects forecasted the falling spot prices that continue to be observed in the NEM, as sponsors and market forecasters would not have foreseen the ongoing capital cost reductions that led to significant penetration of rooftop and utility scale solar by 2019 and 2020. As electricity spot prices continue to fall so too have the accuracy of the forecasts initially made by LSS projects.

Similarly the revenue from spot prices and creation of Large-scale Generation Certificates (LGCs) displayed a wide variation between forecast and actual values. On average, forecasts for volume weighted price of energy dispatched to the grid in 2020 were 19 per cent above actual whilst the value of LGCs created for dispatched generation was almost 40 per cent lower than forecast. One project in NSW underestimated the volume-weighted spot price by 36 per cent, while another project in QLD overestimated it by 157 per cent which clearly shows the range in forecasting accuracy both over and under actuals.

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Above image: Fulcrum 3D CloudCAM
Cover image: Oakey 2 Solar Farm

FORECASTS VS ACTUAL

SOLAR RESOURCE

ARENA's Knowledge Sharing Plans (KSPs) for Large-scale Solar projects obliged each funding recipient to submit various amounts of project related data in accordance with ARENA's Data Specification.

One forecast provided by each project in 2016 via ARENA's standardised Levelised Cost of Electricity (LCOE) spreadsheet was the annual 50 per cent probability of exceedance (P50) GHI estimate (the P50 GHI Estimate). It is important to note that forecasts were made by projects at the time of ARENA grant application and that some variables were updated following that point in time. The annual GHI is the total irradiance to fall on the solar farm in the horizontal plane of array over one year. The P50 value for this variable is that which is expected to be exceeded with a 50 per cent probability in a future time interval. For example, in any given year, it is expected that the actual total GHI to occur will exceed the P50 GHI Estimate with 50 per cent probability i.e., there is an equal chance of actual GHI to be higher or lower than forecast GHI. A P50 case is often the basis of equity investors' expectation of production. Not all proponents provided P50 GHI Estimates for solar resource in the LCOE spreadsheet and therefore some projects are omitted from this analysis.

Once each project was operational, GHI data was recorded at each LSS site's ground weather station(s) and submitted to ARENA as agreed in their KSP. It is common for data loggers to miss periods of data collection, or for certain data to show errors. Submitted data is processed and cleaned before comparing with forecasts. Figure 2 shows a snapshot of the GHI data submitted by each LSS proponent before and after the data processing stage. Depending on the quality of data submitted by each project, the data processing stage resulted in either one or two complete years (i.e., 2019 and/or 2020) of clean GHI data to be used for comparison against forecasts.

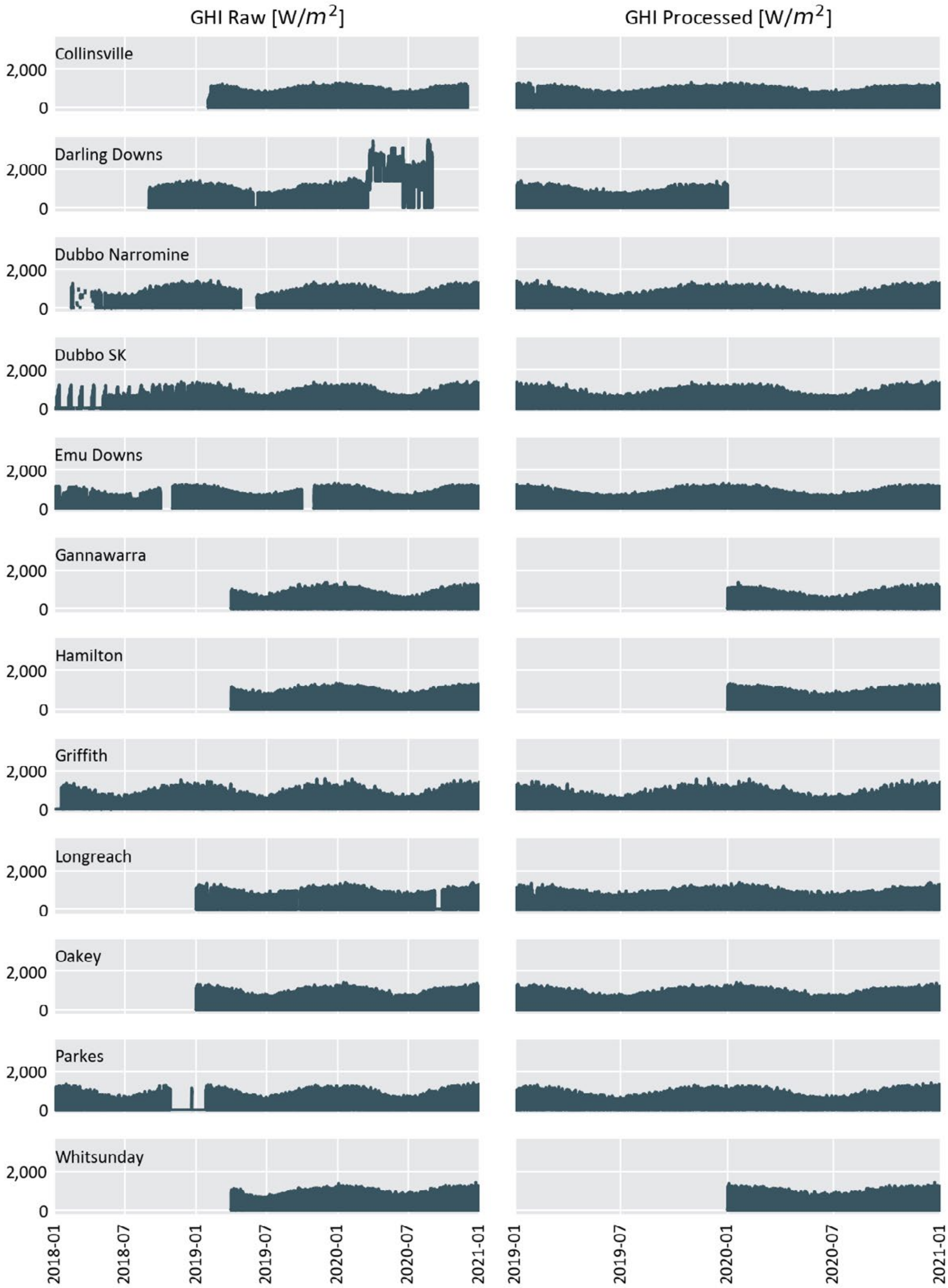

Figure 2. Raw measurements provided for global horizontal irradiance by each LSS proponent before and after data processing to get one, or two where possible, years of clean irradiance data.

Figure 3 shows how each P50 GHI estimate from the LSS portfolio compares to the recorded GHI for years 2019 and 2020. Overall, it appears that 2019 was a sunnier year (higher GHI) for all but one of the LSS projects. On average, 4.45 per cent more GHI reached the LSS farms in 2019 than in 2020. On average, P50 GHI estimates were approximately 5 per cent below the amount of GHI in 2019, whereas this value was closer to 1 per cent in 2020. For both 2019 and 2020, one project's P50 GHI estimate was almost 8 per cent below actual. In 2019 none of the projects' P50 GHI estimate exceeded the recorded GHI; however, three did in 2020. One project's P50 estimate exceeded actual GHI in 2020 by almost 4 per cent.

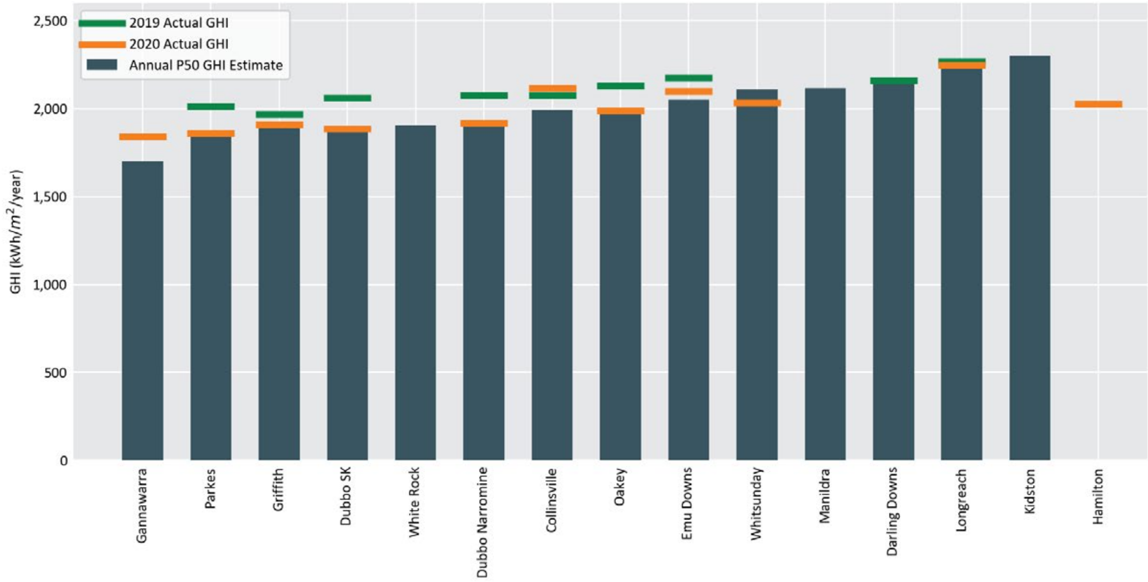

Figure 3. Forecast compared to actual GHI data for each of the LSS projects. NB not all Project's submitted complete data sets. Whitsunday forms an appropriate analogue for Hamilton in this plot due to their similar size and geographic location.

Table 1 reports the average, minimum and maximum for annual GHI P50 estimates and the measured annual GHI in 2019 and 2020.

TABLE 1. SUMMARY STATISTICS OF ESTIMATED AND ACTUAL ANNUAL GHI

ANNUAL GHI [KWH/M2]	P50	2019	2020
Mean	2,009	2,103	1,993
Minimum	1,700	1,967	1,839
Maximum	2,298	2,269	2,247

In summary, the P50 estimates of GHI proved to be reasonably accurate despite some small variations and missing data.

GENERATION

Report One from ARENA's Generator Operations Series: Large-scale Solar Operations (arena.gov.au/knowledge-bank/report-one-large-scale-solar-operations/), discusses how each successful applicant of ARENA's LSS funding round submitted detailed project financial models during the application stage in 2016. These models include confidential information about how investors accounted for expected losses to generation. Common considerations contributing to lost generation include weather, module degradation, unavailability, parasitic losses, and marginal loss factors (MLFs). Curtailment was rarely included in these models in 2016, although it is possible that curtailment studies may have been subsequently commissioned for incoming investors at financial close.

LSS proponents provided P50 and P90 estimates for annual energy dispatched to the grid in 2019 and 2020. For each project, Figure 4 compares the Project's forecast energy dispatch estimates (excluding MLF) to AEMO's NEMweb aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/data-nem/market-data-nemweb (AEMO's market database that includes TOTALCLEARED datasets) records for energy dispatch values in 2019 and 2020. To keep data anonymous across projects, generation values have been represented on a MWh/MW_{DC} basis.

On average, P50 estimates were 8 per cent above P90 estimates for energy dispatched. One project's P50 estimate exceeded the P90 estimate by 19 per cent, while another's exceeded it by 4 per cent. Across both years, the portfolio's average P50 and P90 estimate for annual energy dispatched was 2,015 MWh/MW_{DC} and 1,864 MWh/MWDC, respectively.

On average across the portfolio for both 2019 and 2020, the P50 estimate exceeded the actual energy dispatched by approximately 12 per cent (i.e. the projects generated 12 per cent less energy on average than their P50 estimates). Across the years analysed, one Project's forecast annual P50 estimate exceeded actual energy dispatched by almost 24 per cent, while another Project underestimated actual energy dispatched by 9 per cent.

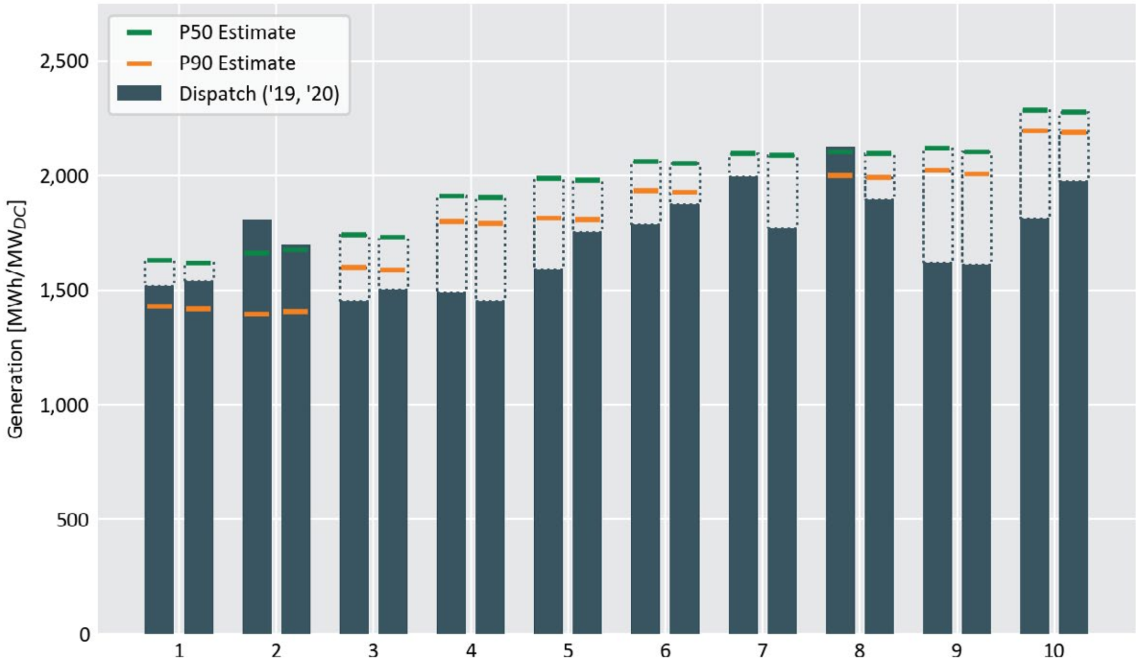

Figure 4. Comparison of AEMO's records for energy dispatch and Project's estimates across the LSS portfolio for year 2019 and 2020. NB Project 7 did not submit a P90 estimate.

Of the projects that provided sufficient data, P90 estimates for annual energy dispatched exceeded actual energy dispatch records on 6 of the 10 projects. Given the P90 estimate is the value of energy that can be expected to be exceeded in any given year with a 90 per cent probability and the actual irradiance was relatively close to forecast irradiance as per the analysis above, it is clear that the underperformance was contributed to by constraints imposed on generation that were unexpected and not forecast in original estimates. These types of constraints could include plant availability, the requirement to curtail generation for local grid conditions (e.g. grid security or during grid upgrades) as well as economic curtailment in periods of negative pricing. If detailed performance ratio calculations prove underperformance to be at the fault of the engineering, procurement, and construction contractor (EPC), then the EPC will be liable for liquidated damage payments. In order to determine who carries volume risk, detailed PR calculations must be undertaken that involve correcting for several aspects (e.g. weather, grid-constraints, performance etc.) to understand the breakdown of performance, and ultimately understand who bears the cost.

ELECTRICITY SPOT AND LGC PRICE

Forecasts were provided by most projects for electricity and LGC spot price. Forecasts were provided in nominal (i.e., before adjusting for inflation) and real (i.e., adjusted to remove the effect of inflation) terms, where values reported on in Figure 5 are in real terms. It is assumed that the annual electricity spot price forecasts provided by each project reflect what each proponent expected the volume weighted spot price of energy to be in each respective region of the NEM. Today, merchant contracting remains a major risk for renewable energy investments and there is still large uncertainty when forecasting electricity spot price, which is reflected by the disparate forecasts from each of the projects. Indeed, electricity price forecasting models generally solve to the long-run marginal cost of the next generator entrant required to meet forecast demand. Changes in inputs such as solar and wind construction costs, penetration of rooftop solar and increasing energy efficiency on the demand side over time, will of course impact on price forecasting.

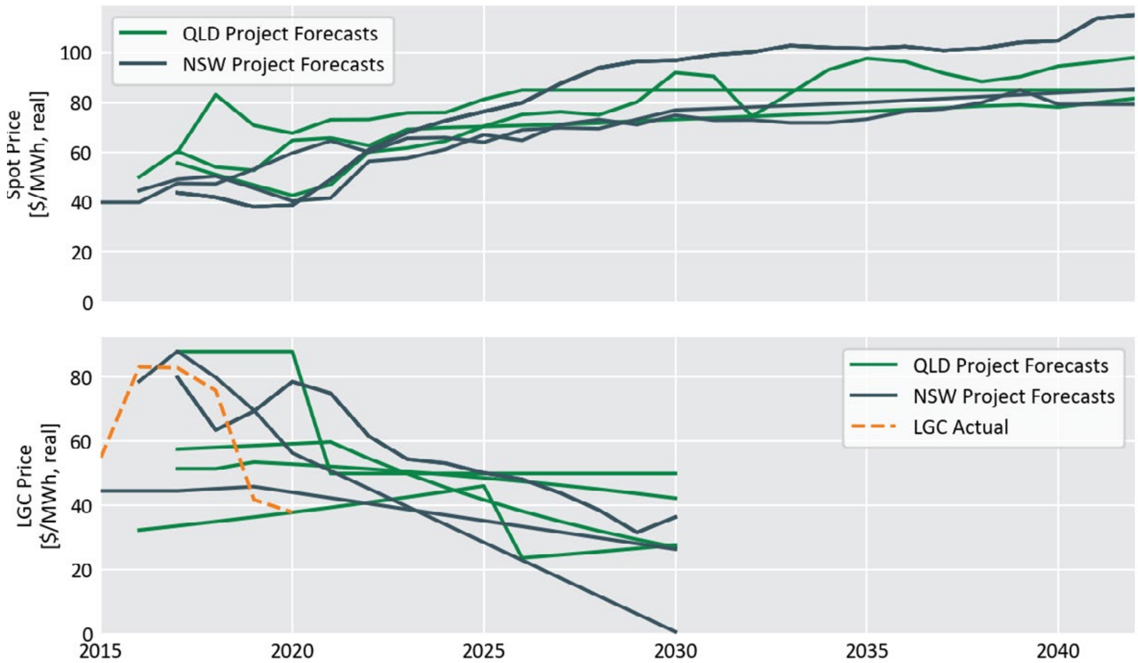

Figure 5. Electricity spot price and large-generation certificate price forecasts, in real terms, submitted by LSS Projects's in 2016.

Ten LSS projects provided electricity spot price forecasts for 2020, however four of those forecasts are not included in this analysis. One is relevant to the South West Interconnected System (SWIS), and another three forecasts are identical as they were provided for the same region by the same developer. This resulted in three QLD and three NSW electricity price forecasts being used. The QLD electricity price forecasts for 2020 were $43, $65 and $68 per MWh. The QLD electricity price forecasts for 2020 were $39, $41, $60 per MWh. Interestingly, all forecasts for electricity spot price tend to increase over time, however, the average 5-minute trading interval spot price during daylight hours is 35 per cent lower in 2020 than in 2019 and negative pricing occurred in 20 per cent of all trading intervals over Australia's most recent summer period [1]. If this falling trend continues, then the original LSS electricity price forecasts will become increasingly disparate from actuals.

The LGC traded price has fluctuated greatly over the last five years. The average LGC price in both 2016 and 2017 was $83 per MWh, while it currently sits about 49 per cent below this price in 2022, at $42.50 per MWh. The forecasts for LGC prices are incredibly disparate across the portfolio of projects, ranging from $38 to $88 per MWh in 2020. On average, the LGC forecast for 2020 is $62 per MWh, but in reality the average price was $38. Exact prices received for LGCs on each project is not known as they can be traded at a time of the owners choosing.

Historical energy dispatch actuals (TOTALCLEARED data) for each semi-scheduled LSS project on the NEM and Regional Reference Prices (RRP) for Queensland (QLD), New South Wales (NSW), and Victoria (VIC) were downloaded from AEMO's public database. AEMO does not record actuals for non-scheduled LSS generators, in which case generation data submitted directly to ARENA by Projects was used.

All generation within each 30-minute trading interval within a State is paid the same spot price for that same settlement period. Each project's annual market revenue was divided by the annual sum of dispatched energy to determine the volume weighted spot price received over the year. These values are calculated for each project in 2020 and compared to their forecast for that same year during ARENA's LSS funding round application stage. The annual revenue in 2020 per MWDC installed is also calculated and compared across the portfolio. The installed MWDC size is a good indicator of capital expenditure, and this metric therefore attempts to compare spot market returns across the portfolio. The results are shown in Figure 6. Not all projects provided clear forecasts for electricity spot price and were therefore omitted from parts of the analysis.

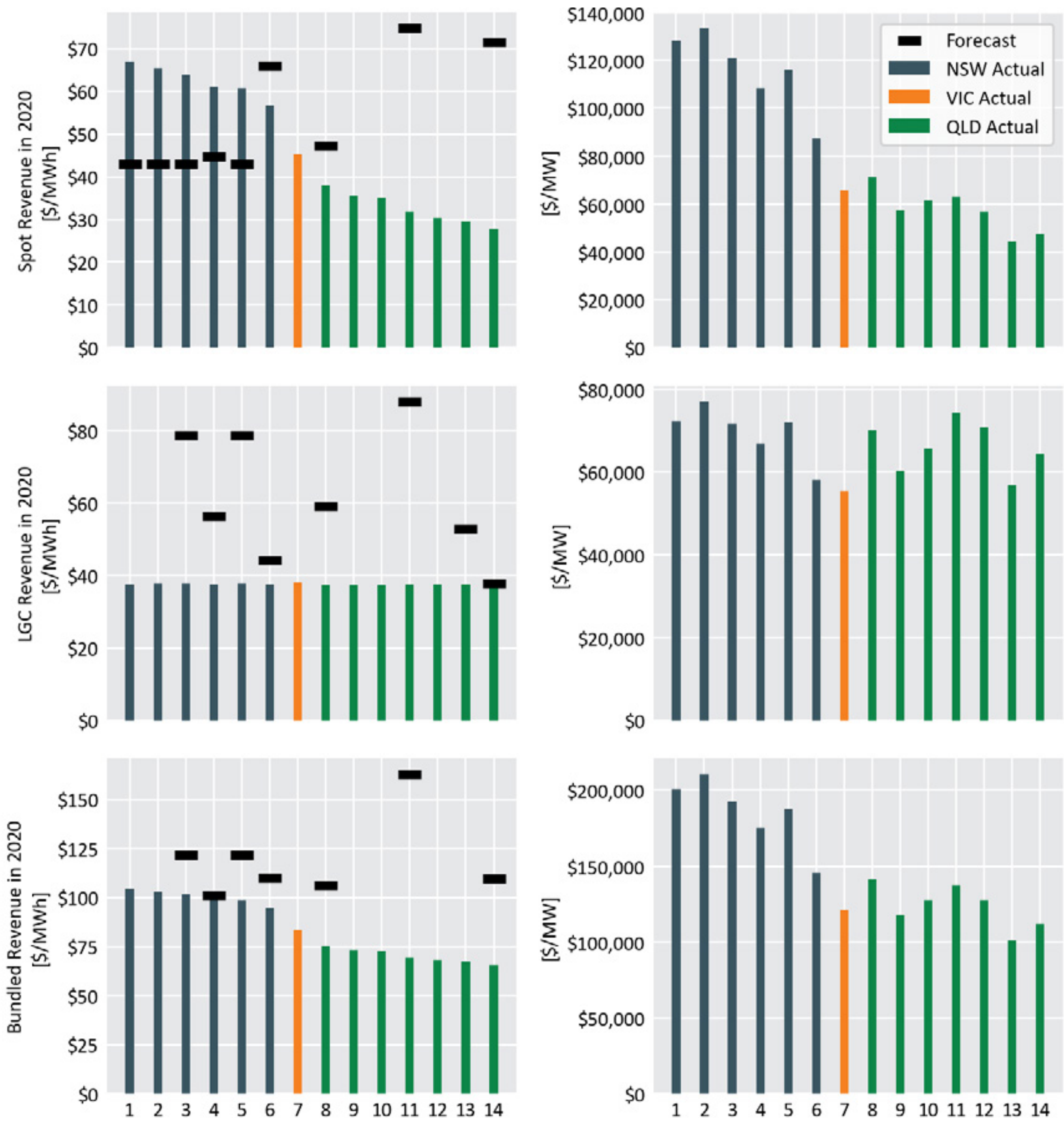

Figure 6. Forecast vs actual for volume weighted spot price of energy, LGC revenue, and the combined bundled energy revenue, represented as both $/MWh and $/MWDC installed in 2020. NB not all projects provided forecast data.

Dispatched energy in 2020 was downloaded for fourteen of ARENA's LSS projects. Six of these projects are in NSW, one in VIC, and seven in QLD. On average, the fourteen projects included in this analysis received, in 2020, $46 per MWh in spot revenue, and $38 per MWh in LGC revenue[2]. One project in NSW received $67 per MWh in spot revenue, and one project in QLD received $28 per MWh in spot revenue. On average, projects in NSW, VIC, and QLD received $63, $45, and $33 per MWh from the spot market, respectively. The total bundled energy price received, on average, for projects in NSW, VIC, and QLD was $101, $83, and $71 per MWh, respectively.

It's clear from Figure 6 that projects in NSW received the highest price for energy in 2020, when compared to projects in VIC and QLD. As discussed in ARENA's third report in the Generator Operations Series: Negative Pricing and Bidding Behaviour in the NEM (arena.gov.au/knowledge-bank/genops-three-negative-pricing-and-bidding-behaviour-on-the-nem/) [2], NSW experiences the smallest occurrence of negative pricing events across all NEM regions. This is largely due to its relatively central location on the NEM (enabling import/export from neighbouring regions) and relatively smaller solar contribution to energy supply. Higher contributions from solar in QLD and VIC are flooding the daytime energy supply and applying downward pressure on daytime prices, ultimately reducing the volume weighted spot price of energy for solar in these regions.

2 LGC's have been assumed to be traded at the mid-point price at the time of generation

For the ten LSS generators on the NEM that submitted sufficient price forecast data, forecasts for volume weighted price of energy delivered to the grid in 2020 were, on average, 19 per cent above actual. One project in NSW underestimated the volume weighted spot price by 36 per cent, while another project in QLD overestimated it by 157 per cent. These statistics highlight the significant discrepancy between expectations and reality when it comes to spot price received for energy delivered to the grid. Most projects have offtake agreements in place covering the majority of generation and therefore do not rely on spot market revenue as a source of income. Despite this, these statistics still present useful insights for off-takers and help to more accurately price future power purchase agreements (PPAs).

The spot market revenue in 2020 per MWDC installed ranged from $44,000 to $133,000 per MWDC, where the average across the 14 projects was $83,000 per MWDC. Forecasts for revenue from LGCs in 2020 were consistently above actual LGC revenue.

IMPACT OF CONTRACTING, INCLUDING SOLAR 150 PPAS

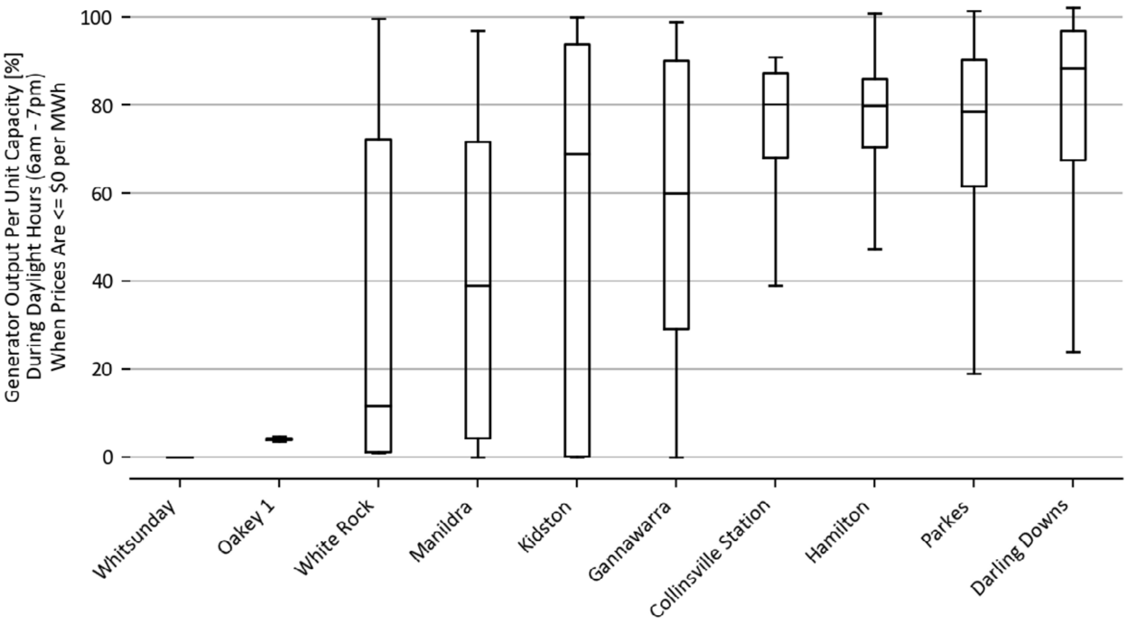

Figure 7.

The Queensland Government's Solar 150 program (www.business.qld.gov.au/industries/mining-energy-water/energy/renewable/projects-queensland/solar-150) provided financial support to six large-scale solar farms through long-term contracts for difference. To be eligible for a Solar 150 PPA projects had to be located in Queensland, connected to the NEM and had already received a funding offer under ARENA's LSS funding round. Solar 150 PPAs were awarded to the Darling Downs, Whitsunday, Kidston, Oakey, Longreach and Collinsville projects.

At the time of contracting, these offtake agreements were considered very low risk due to their long tenor and creditworthy offtaker. However, analysis of NEM generation data reveals that projects with the Solar 150 PPA stop exporting during periods of negative pricing. This happens even when the LGC value would justify exporting, and when nearby projects continue to generate. These generation patterns suggest that the terms of the Solar 150 PPA require the projects to stop generating during periods of negative spot prices. The projects switch off at different levels of negative pricing which suggests that the level of merchant exposure varies between projects.

This risk of curtailment may not have been anticipated by the sponsors at the time of bidding to ARENA due to the low penetration of utility solar in Queensland at the time. However it has certainly been a risk experienced in the first years of operations (see ARENA's third report in the Generator Operations Series: Negative Pricing and Bidding Behaviour in the NEM (arena.gov.au/assets/2021/09/the-generator-operations-series.pdf) [2]).

SUMMARY

The data and information submitted by ARENA's LSS projects covering project feasibility, development and two full years of generation continue to provide the industry with valuable insights. This study has highlighted the difference between what was expected and what actually happened for solar resource, generation and revenue (both from the wholesale energy and LGC markets). The disparities shown to exist provide valuable data points that can help to inform the industry on the levels of uncertainty to be expected today when forecasting these variables into the future. These are critical components for investors to understand before making final investment decisions.

This study has demonstrated how the significant changes in NEM dynamics over the past few years have made the task of forecasting key financial project parameters particularly difficult.

Image: Moree Solar Farm

REFERENCES

[1] ARENA, "Large-scale solar operations," ARENA, Canberra, 2021.

[2] ARENA, "Negative pricing and bidding behaviour in the NEM," ARENA, Canberra, 2021.

Further information is available at
arena.gov.au

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