# Mid-scale solar outlook 2023 to 2027
# Systems above 100kW to 30MW

Report to the Clean Energy Regulator

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# 1. Executive Summary

Green Energy Markets has been commissioned by the Clean Energy Regulator to provide a projection of levels of mid-scale solar capacity installed by year for the period of 2023 to 2027. Mid-Scale capacity is defined as solar systems above 100 kilowatts and up to 30 megawatts[1]. The projection covers:

- Systems installed on electricity consumers' premises in a behind the meter configuration (where the generation can be self-consumed to offset the need to purchase power from the grid at the retail-delivered price of electricity)
- Systems installed as power plants in front of the meter which are dependent on revenue tied to the value of the wholesale electricity market; and
- Systems installed in remote or off-grid power systems where their primary benefit is to reduce gas and diesel fuel use to supply power.

All charts and figures provided in this report exclude systems and capacity registered under the Small Scale Renewable Energy Scheme.

Projecting uptake within this narrow sub-sector of the solar market is subject to considerable uncertainty because the market is highly immature and still undergoing rapid development and change and is characterised by a relatively small number of systems in each state.

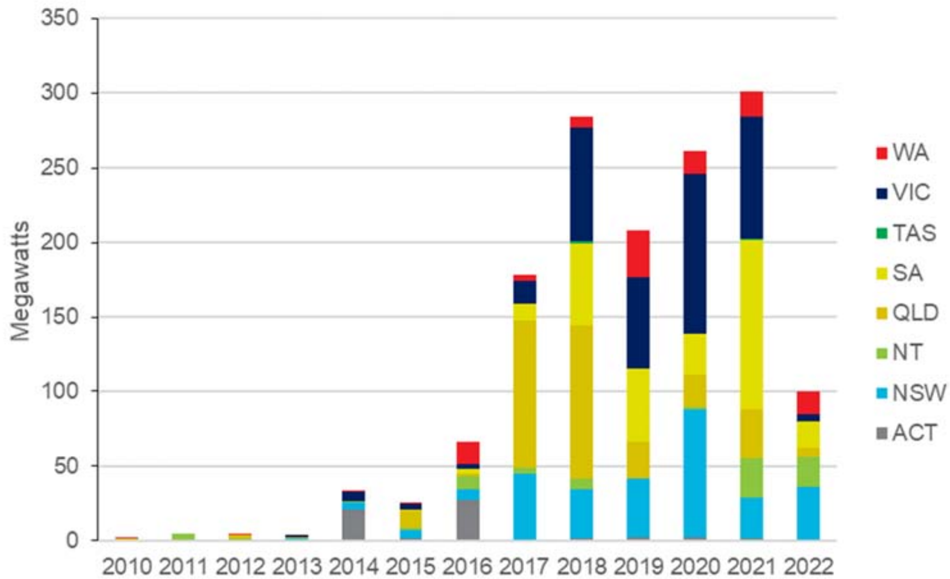
As shown in Figure 1-1 the market has only really emerged at any noticeable level since 2017. This is as a result of significant reductions in system costs, and a dramatic increase in the wholesale price of electricity in the east-coast National Electricity Market. It underwent rapid growth between 2016 and 2018 but has since shown volatile levels of installs on an annual basis, falling in 2019 before recovering and installing a record amount of capacity in 2021. But over 2022 up until July the average rate of monthly capacity applications has plummeted to levels well below those experienced in 2018, 2020 and 2021 (although not dissimilar to 2019).

Complicating matters in projecting uptake is that the underlying supply-demand balance for electricity is changing rapidly due to a large influx of solar and wind capacity within a short period of time. Up until this year (with the surge in international gas and coal prices), this capacity had acted to substantially depress the wholesale market value of electricity during daytime periods. In the states of Queensland, South Australia and Western Australia wholesale market prices had been reaching record lows over daytime periods and was also becoming a feature in NSW and Victoria. This will noticeably reduce the revenue gain (or avoided electricity cost) solar systems provide over the medium term.

On the counter side, disruptions in supply of Russian gas and coal, have led to unprecedented international prices for these two energy commodities which have then flowed through to the fuel costs faced by many Australian gas and coal power stations. This has caused east-coast National Electricity Market (NEM) wholesale prices to rise to sustained heights well beyond anything experienced since the formation of the NEM. These are then leading to rises in retail delivered electricity prices and what appears to be a decline in levels of retail market competition. How long prices might remain at such elevated levels is highly uncertain.

[1] In practice there is a very small amount of capacity captured in this analysis involving some systems that are below 100kW in scale but have elected to register under the Large-Scale Renewable Energy Target to create Large-Scale Generation Certificates rather than STCs. In 2019 these systems represented 0.03% of total capacity accredited for LGCs involving systems of 30MW or less capacity. For modelling convenience and given their insignificance they were not specifically excluded from the historical dataset.

**Figure 1-1 Capacity of solar systems up to 30MW by application year**




*Note: 2022 numbers are only up to July. Some of the capacity within this chart incorporates projects which have applied for accreditation but are yet to be accredited. For these projects, as well as those accredited, capacity is recorded against the year in which the application was received.*

This report's projections of solar uptake are based on a combination of:

- **Interviews** with a range of solar industry participants that have experience in the mid-scale segment of the solar market. The selection of interviewees seeks to draw together a small group of experienced industry participants that once combined provides a good overview of conditions in the market from both a qualitative and quantitative perspective who have enough experience in the industry to evaluate market behaviour and changes in an historical context. It has included solar retailers, equipment suppliers, the largest commercial solar LGC creator (Green Energy Trading), solar project developers and construction firms as well as consultants and service providers to the solar sector;
- **Bottom-up research** identifying near-term, significant solar roll-out plans by organisations with significant building portfolios and project developers.
- **Financial modelling** of the payback periods for investing in solar systems across different states. Uptake in 2023 to 2027 is calibrated against uptake and payback periods for prior years. However, while the financial modelling provides a baseline of indicative projected installations over the period to 2027 these are then adjusted to take into account the information gathered via interviews and the bottom-up research.

Table 1-1 provides the resulting nation-wide estimates of capacity installed over the outlook period.

**Table 1-1 Projected mid-scale total megawatts accredited/installed**

| State/Territory | 2023 | 2024 | 2025 | 2026 | 2027 |
|---|---|---|---|---|---|
| ACT&NSW | 120 | 98 | 87 | 54 | 54 |
| NT | 1 | 1 | 1 | 1 | 1 |
| QLD | 36 | 43 | 44 | 32 | 26 |
| SA | 18 | 25 | 14 | 14 | 14 |
| TAS | 1 | 6 | 11 | 6 | 6 |
| VIC | 71 | 55 | 58 | 52 | 52 |
| WA | 4 | 41 | 11 | 11 | 11 |
| Off Grid - all states | 71 | 61 | 50 | 50 | 50 |
| **TOTAL** | **322** | **330** | **277** | **221** | **215** |

The average amount of annual LGC production each year's installed capacity would create is detailed in Table 1-2. Please note that these numbers are well below the installed systems' likely power generation because our analysis indicates that owners of behind the meter systems would be financially better off registering their systems to create either Victorian Energy Efficiency Certificates when located in Victoria from 2023 onwards or Australian Carbon Credit Units in other states from either 2026 or 2027 onwards.

**Table 1-2 Annual ongoing LGCs by year of plants' accreditation**

| State/Territory | 2023 | 2024 | 2025 | 2026 | 2027 |
|---|---|---|---|---|---|
| ACT&NSW | 211,914 | 163,679 | 141,774 | 42,048 | 42,048 |
| NT | 1,350 | 1,426 | 1,503 | 0 | 0 |
| QLD | 46,775 | 64,744 | 69,588 | 50,264 | 0 |
| SA | 27,319 | 40,872 | 18,710 | 18,710 | 0 |
| TAS | 1,323 | 10,842 | 20,163 | 10,843 | 9,198 |
| VIC | 0 | 0 | 0 | 0 | 0 |
| WA | 5,879 | 58,838 | 18,510 | 10,512 | 10,512 |
| Off Grid - all states | 106,394 | 90,514 | 74,460 | 74,460 | 74,460 |
| **TOTAL** | **400,954** | **430,915** | **344,707** | **206,837** | **136,218** |

## 2. Overview of the Market

**The mid-scale solar market remains volatile and subject to significant uncertainty**

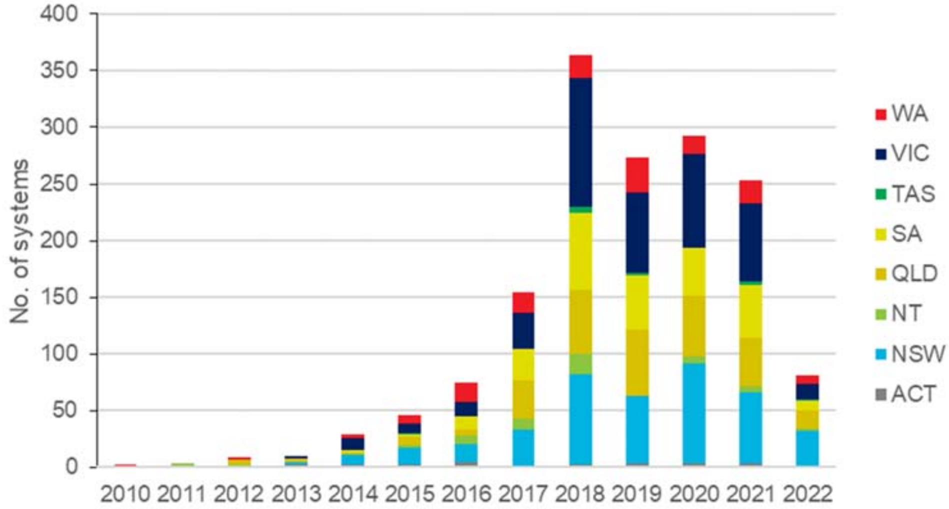
As detailed in prior years' projections, assessing the likely trajectory of installations for mid-scale solar systems (defined as those 100 kilowatts and up to 30 megawatts in capacity) is subject to considerable uncertainty.

Factors making it difficult to predict future installations include the fact that the market is immature and still undergoing rapid development and change. Prior to 2016 solar systems larger than 100kW were not really a commercial proposition to electricity customers where a large proportion of network charges are recovered via demand-based tariffs[2]. In addition, while solar was a more viable financial option for use in remote applications for displacing diesel fuel, it's widespread use was limited due to other factors such as unfamiliarity with the technology, concerns around maintaining power system reliability, and the fact that energy costs are often a relatively minor driver of financial performance in mining activities. Lastly, solar was substantially more expensive than wind power and so uncompetitive for provision of LGCs and electricity for the wholesale market.

As shown in Figure 2-1, the number of systems installed in Australia prior to 2016 was very small, with just 42 systems accredited in 2015, 31 in 2014 and an average of just 8 per annum from 2010 to 2013. The most installed in any single state was just 15 prior to 2016. This very small sample set over a short period of time makes it difficult to draw confident inferences about how the market responds to different factors likely to influence uptake. Also while the market was characterised by rapid growth in system numbers over 2014 to 2018, this abruptly ended in the subsequent year. While numbers were then subsequently steady to 2021, the rate of applications seen so far over 2022 indicate a collapse in the market, particularly behind the meter systems. This may recover over the back half of 2022 given the spike in wholesale electricity market prices, but shows that the mid-scale solar market is currently highly volatile.

[2] This is where a customer is charged by the power network provider on the basis of their maximum kilovolt-amp or kVA demand drawn from the network across any individual 30 minute interval over the measured period, rather than their overall consumption of kilowatt-hours on the network.

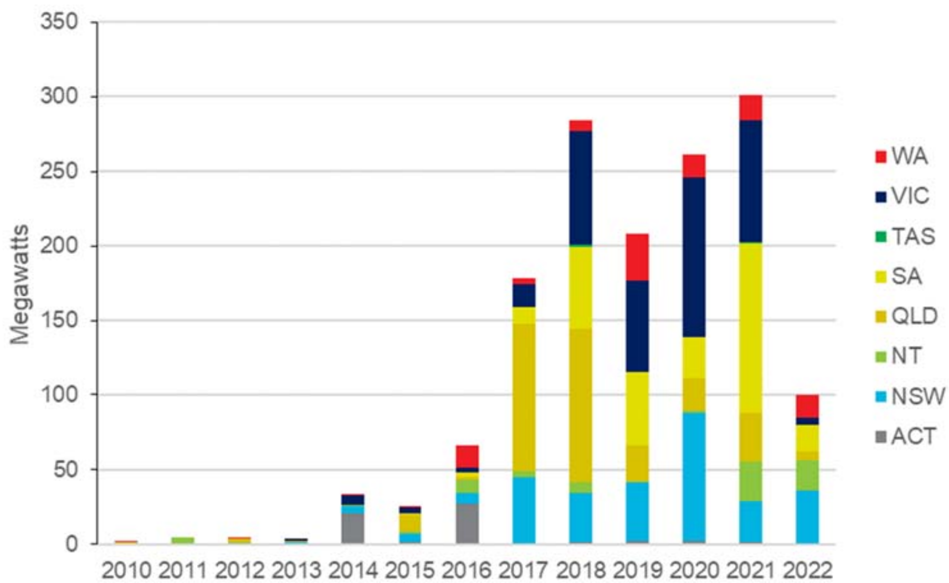
**Figure 2-1 Number of mid-scale solar systems by year of application (up to 30MW)**




*Note: 2022 numbers are only up to July. Some of the systems counted within this chart are projects which have applied for accreditation but are yet to be accredited. For these projects, as well as those accredited, capacity is recorded against the year in which the application was received.*

In terms of megawatts of capacity (shown in Figure 2-2), an increased prevalence of larger sized power stations being registered for accreditation in 2020 and 2021 has acted to disguise the fall in system numbers after 2018.

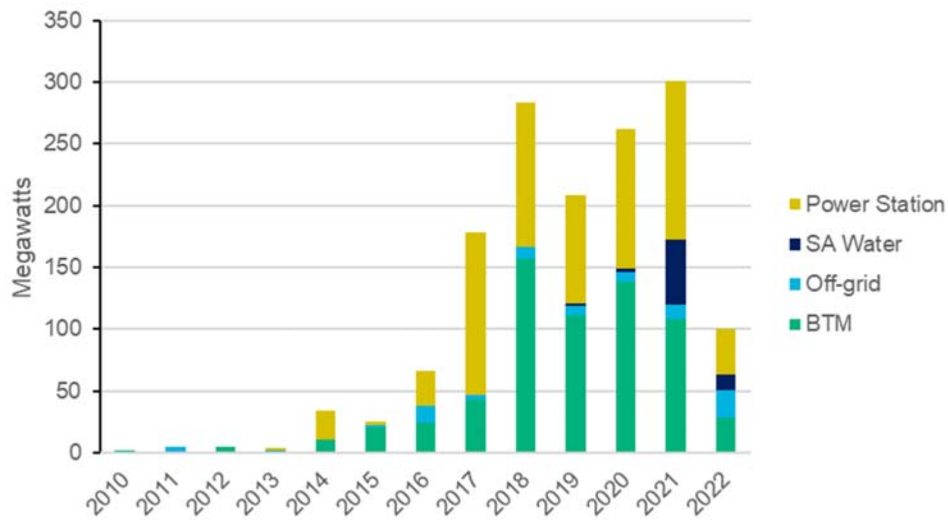
**Figure 2-2 Capacity of mid-scale solar systems by year of application (up to 30MW)**




*Note: 2022 numbers are only up to July. Some of the capacity within this chart incorporates projects which have applied for accreditation but are yet to be accredited. For these projects, as well as those accredited, capacity is recorded against the year in which the application was received.*

If we recut these capacity numbers to drill into the end use segment in which the solar was used and also separate out the influence of SA Water's very large organisation wide solar roll-out (as shown in Figure 2-3), one can more easily see the decline in the behind the meter part of the mid-scale solar market. Based on historical patterns, around 60% of the yearly capacity in the behind the meter segment is registered for LGCs between January and July with the remainder coming in rest of the year. If such a pattern was repeated in 2022 then only 50MW of behind the meter solar would be registered for the year (excluding SA Water), less than half what was achieved in 2021. Although, the end result should be larger than this due to some multi-megawatt projects which are due for completion before the end of the year.

**Figure 2-3 Capacity of mid-scale solar systems by end-use segment (up to 30MW)**




*Note: 2022 numbers are only up to July. Some of the capacity within this chart incorporates projects which have applied for accreditation but are yet to be accredited. For these projects, as well as those accredited, capacity is recorded against the year in which the application was received.*

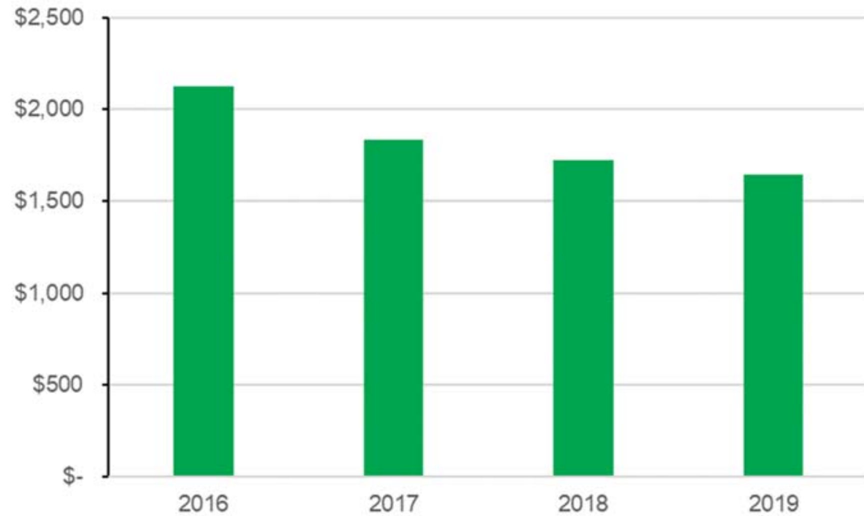
The small numbers of installations until just recently means there is a scarcity of historical data with which to assess statistical relationships between uptake and possible causes of increased uptake that might facilitate precise quantitative analysis. However, the fact that numbers of systems and capacity has risen and then fallen in response to changes in financial attractiveness (explained further below) suggests projections of payback should be a useful guide to how installs should change over time.

**The cycle of growth and now a decline in behind the meter system numbers shows a close link to the financial attractiveness of solar as a cost saving investment**

Even though the limited sample set constrains the ability to develop a precise and confident relationship between uptake and plausible variables that influence uptake, what is clear is that the behind the meter market's rapid growth from 2016 to 2018 and then the subsequent fall was predominately a function of changes in the financial attractiveness of solar systems relative to end consumers buying power from the grid.

Based on the sample set provided by the Clean Energy Regulator, system cost per kilowatt declined by around 25 percent between 2016 and 2019.

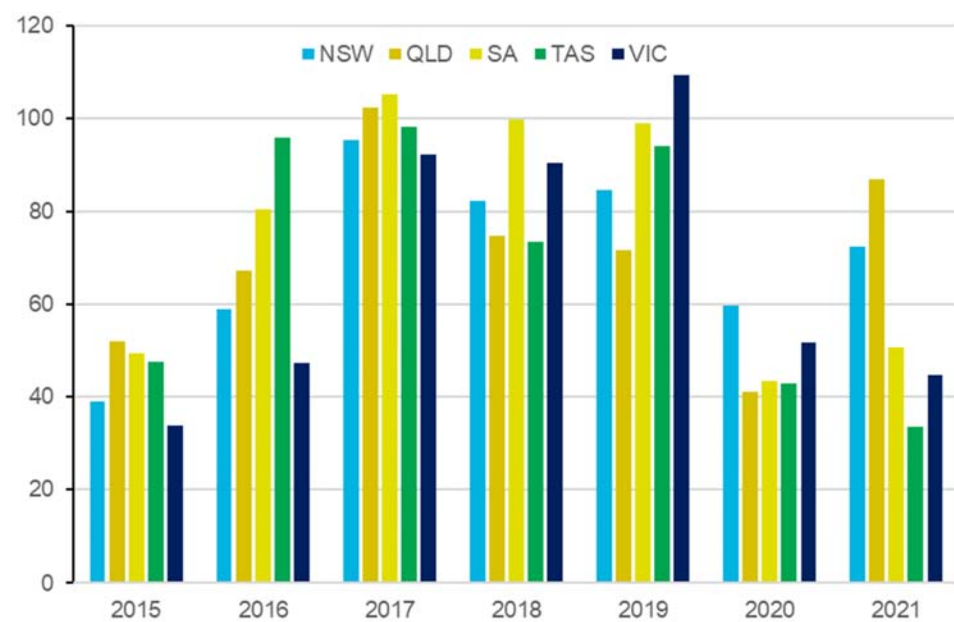
**Figure 2-4 Cited installed cost of mid-scale systems per kilowatt by year (excluding off-grid/remote grid systems)**




*Note: Prices are GST excluded. These numbers are drawn from a sample which is adjusted to remove both low and high-end price outliers. In addition off-grid or remote grid systems have been excluded because these usually involve substantial additional costs not faced by mains grid-connected systems which then act to skew the cost data upwards in years in which off-grid systems were accredited.*

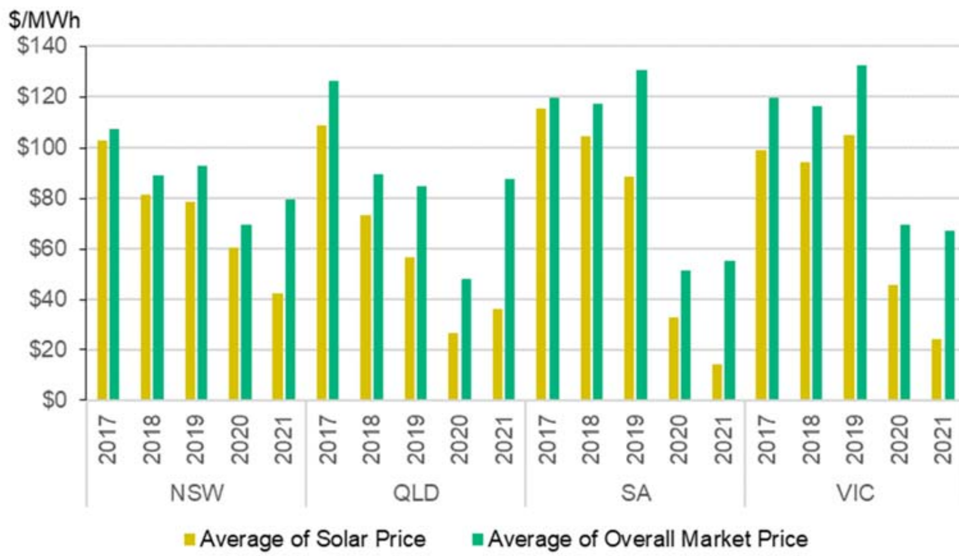
Meanwhile, over the same period we saw a dramatic rise in wholesale electricity prices in the East-Coast National Electricity Market between 2015 to 2017 that would have further enhanced the attractiveness of solar to customers and helped drive the markets rapid growth. But these wholesale price rises subsequently reversed by 2020 and we expect that the fall in solar system numbers after 2018 was a function of a realisation by large electricity consumers that power prices would fall, therefore diminishing the financial benefit a solar system would deliver (see Figure 2-5).

**Figure 2-5 Average time-weighted wholesale electricity spot price by state**



This would have been further reinforced by the fact the fall in wholesale prices was particularly marked over daytime hours, so the decline in the wholesale value of electricity from solar generation was even greater. This is illustrated in Figure 2-6 which shows the average wholesale market spot price value associated with the generation profile of rooftop solar in each state (shown in yellow) relative to the average wholesale spot market value for overall generation within each state (shown in green).

**Figure 2-6 Average wholesale spot price for solar versus overall market**




For customer sites potentially suitable for behind the meter systems larger than 100kW, changes in wholesale market energy prices have a far greater impact on kilowatt-hour charges than for smaller customers such as the residential market (whose network charges are recovered based on consumption of kilowatt-hours). And, of course, these prices are the predominant driver of revenue for in-front of the meter power station installations.

The final factor that helped drive a dramatic improvement in the financial attractiveness of 100kW+ solar systems around 2016 was a significant rise in the LGC spot price which increased from around $30 over 2014 to above $80 in 2016 and 2017. One LGC is awarded to a solar system for each megawatt-hour of electricity it generated so the revenue gain in LGCs almost the same as that captured by the rise in wholesale electricity markets. They subsequently moderated over 2018 and 2019.

Combining the decline in system costs with the increase in revenue from higher wholesale prices and higher LGCs prices, we estimate the payback period on solar systems more than halved for a range of customer sites likely to be suitable for 100kW+ behind the meter systems between 2015 and 2019. After 2020 they then subsequently lengthened by around 30% which led to a decline in system installations.

### The role of lags and customer foresight

An important feature to keep in mind in assessing how changes in system cost and electricity prices flow through to solar uptake is that there can be significant lags involved in customers responding to changes in the economics of mid-scale solar PV by installing and then accrediting these systems.

Firstly, large electricity customers tend to procure electricity via 2 to 3 year contracts. This means that it can take several years before customers experience the impact of changes in wholesale market costs. Secondly the purchasing evaluation and supplier selection process for solar, particularly in large organisations that are often the target market for mid-scale solar, can take many months. Lastly the actual scheduling and then ultimate installation can take several months plus there can be further lags until the system is ultimately accredited with the Clean Energy Regulator.

These lags mean that even though power prices surged over 2016 and 2017 while system costs declined, and both have since largely stabilised, the impact in terms of increased solar system accreditations only came through in earnest in 2018. On the counter side, even though wholesale power prices fell in 2020, the effect on solar installs is probably only being fully seen in 2022.

These lags mean that solar uptake in each year will tend to reflect the economic conditions of a solar system for 12 to 24 months previously. Interviews with industry participants suggested that customers evaluating whether to purchase solar are for the most part basing this on current and recent historical electricity prices, rather than seeking to anticipate likely future supply and demand conditions affecting electricity prices or only those in the short-term of the next three years.

This myopic approach to evaluating whether to purchase solar, along with lags in customer response, mean that when we evaluate likely customer uptake, it is informed by a customer perception of paybacks based on an assumption that they will evaluate the financials based heavily on electricity prices from the prior year and the current year, rather than a detailed outlook over the life of the solar system.

## 3. Market conditions and modelling assumptions

### Solar system costs have been rising but will resume a downward trajectory

Solar system costs for large commercial systems are estimated to have risen over the past two years from around $1,375 per kilowatt in 2020 to $1,540 in 2022. For future costs we assume system costs will resume their long running downward trajectory next year and reach just under $1,090 by 2027 (2022 dollars).

### Wholesale electricity market prices have risen dramatically recently but are expected to resume a downward trajectory during sunlight hours

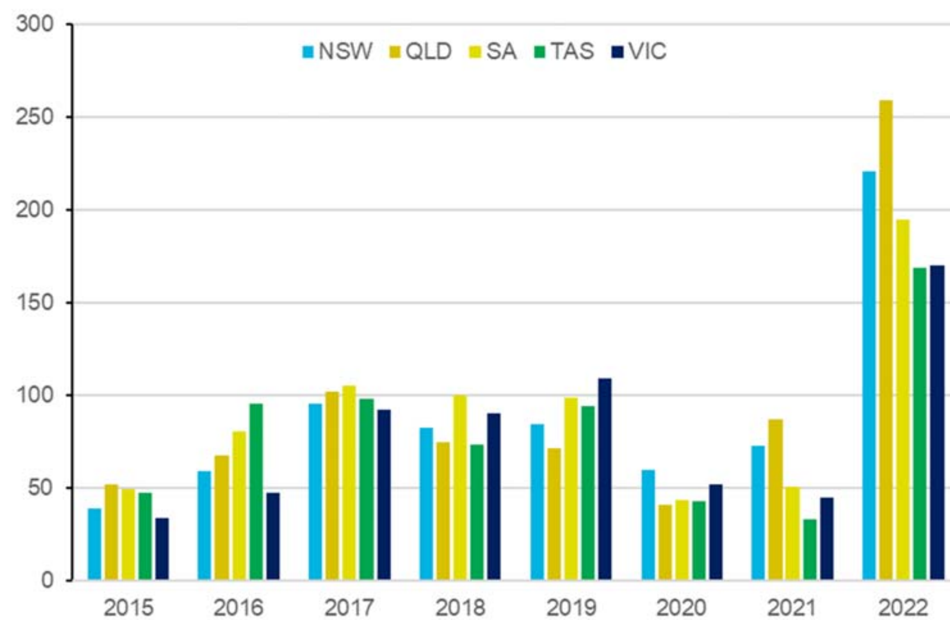
For evaluating the financial attractiveness of mid-scale behind the meter solar systems we assume that customers are on a demand-based network tariff structure. This involves most of the network-related charges being levied on customers based on a peak in their site's demand for power capacity during a 30 minute interval with a much smaller proportion of the costs based on kilowatt-hours of consumption.

Wholesale energy costs are assumed in the model to be recovered from NEM large commercial customers based upon three-part time-of-use structure involving the following:

- Peak period between 3pm to 10pm on weekdays;
- A daylight solar period between 9am to 3pm every day; and
- Off-peak which is all remaining times.

Earlier in Figure 2-5 of this report we illustrated how large commercial behind the meter solar system sales had been supported by a large rise in wholesale energy costs between 2015 and 2017 and likewise there was a substantial fall in wholesale costs after 2019 which preceded a decline in system sales. That chart left out prices for 2022 which have been added in Figure 3-1 below for the year to end of July. This shows that even the elevated wholesale electricity costs of 2017 to 2019 are completely dwarfed by what has unfolded over 2022.

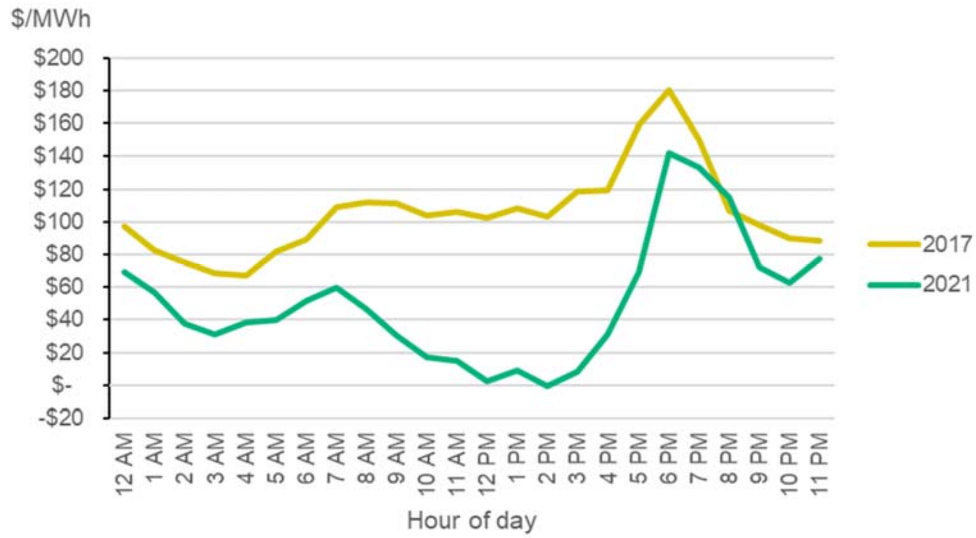
**Figure 3-1 Average time-weighted wholesale electricity spot price by state**




In GEM's prior years' projections modelling has assumed energy prices during daytime periods would reach very low levels. This was informed by forecasts by the Australian

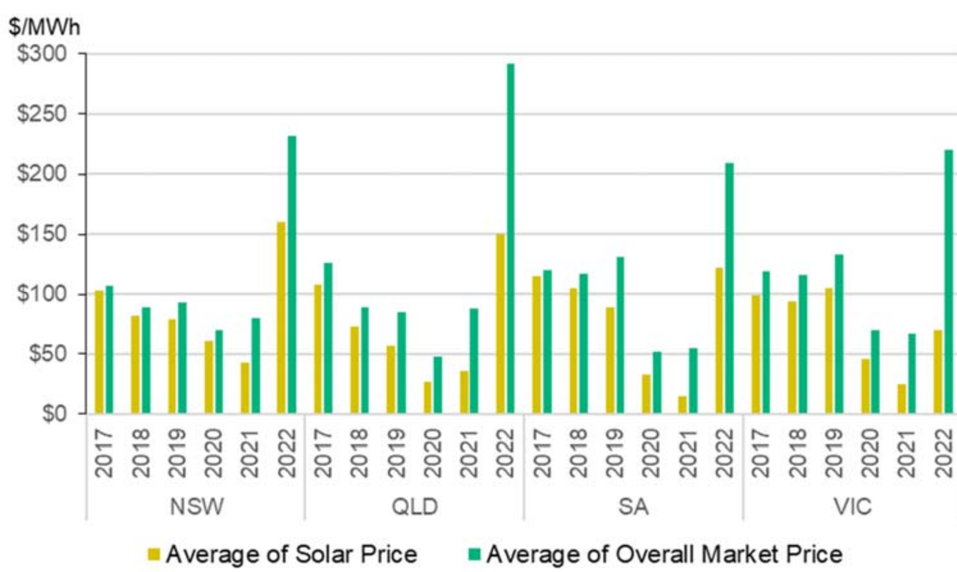
Energy Market Commission and wholesale market outcomes experienced in regions with high penetration of solar, exemplified by South Australia's wholesale market in 2021 relative to 2017 as shown below.

**Figure 3-2 Average SA wholesale prices by hour – 2017 vs 2021**




However, the high wholesale prices which have subsequently unfolded this year, after the AEMC released their most recent projections in December 2021[3], have forced us to make significant upward revisions in likely prices. While solar generation continues to see a large discount in the wholesale value it can capture relative to the overall market, in 2022 wholesale spot prices for solar generation were still very high by historical standards across all NEM states bar Victoria (see Figure 3-3).

**Figure 3-3 Average wholesale spot price for solar versus overall market**




These prices are far above the kind of levels that were anticipated in the AEMC's Electricity Price Trends Report and therefore required us to derive wholesale energy costs via an alternative option to their report. This involved assuming wholesale costs for NEM retailers in 2023 similar to those experienced over 2022 but these were then

[3] Australian Energy Market Commission (2021) Residential Electricity Price Trends 2021.

scaled down over 2024 and 2025 in line with the proportional fall in ASX Baseload contract prices for 2024 and 2025 relative to the 2023 vintage contract. After this point prices were assumed to transition to levels in line with the cost of new entrant generation as detailed by CSIRO's GenCost 2022 publication.

While overall wholesale energy costs are scaled downwards in line with changes in ASX Contract Prices, the price for each tariff period are further differentiated to reflect historical discounts in wholesale energy prices during the solar and off-peak periods relative to the premium seen during the peak period.

NT and WA customers' wholesale energy costs are assumed to be more stable than what we've experienced in the NEM states recently and overall retail charges are derived from current retail offers from Synergy (for WA) and Jacana (for NT). These are then adjusted over time to align with long-run new entrant generator costs for solar and peaking power plants as estimated in CSIRO's Gencost 2022 report.

### LGC prices

LGC prices used for our assessment of paybacks are based on averaged forward prices via reported broker trades over February covering the years of 2023 to 2030 as follows:

**Table 3-1 Assumed LGC prices by year**

| Year | LGC Price |
|---|---:|
| 2023 | $48.25 |
| 2024 | $41.10 |
| 2025 | $36.50 |
| 2026 | $33.00 |
| 2027 | $26.00 |
| 2028 | $21.75 |
| 2029 | $17.00 |
| 2030 | $15.00 |

### Victorian Energy Efficiency Certificate price assumptions

Behind the meter solar systems installed in Victoria can be eligible to create Victorian Energy Efficiency Certificates under the Victorian Energy Upgrades Scheme. The number of certificates a solar system is eligible to create are a function of the estimated greenhouse gas emissions that would be avoided by the solar system's generation displacing the need for electricity that would have otherwise been imported from the grid. The Victorian Energy Upgrades Scheme, similar to the Renewable Energy Target, imposes a legal obligation on electricity retailers to achieve emission abatement targets which are satisfied through surrendering Victorian Energy Efficiency Certificates. While solar systems have to date almost entirely elected to create LGCs, with the price of them expected to decline over the next few years and the duration over which they can be created shortening, creating VEECs from solar is expected to become more financially attractive than LGCs. We assume that all solar systems installed in Victoria from 2023 onwards will elect to create VEECs instead of LGCs. While it is possible for solar systems to create VEECs now (and several systems have created VEECs), the industry is still in the process of developing the systems and processes to create VEECs in a streamlined and administratively easier manner.

Our analysis assumes a VEEC of $70 in 2022 which is in line with averages of brokered market prices in the last few months and that this price is sustained for the outlook period.

### Australian Carbon Credit Unit (ACCU) price assumptions

Solar systems installed behind the meter act to abate carbon emissions by reducing the need for fossil fuel generated electricity from the grid, in a similar fashion as measures that improve electrical energy efficiency or measures which substitute a carbon intensive fuel with a less carbon intensive fuel. Consequently, we assume that behind the meter solar systems would be a valid and eligible means of creating Australian Carbon Credit Units under the Industrial Electricity and Fuel Efficiency Method. Similar to the situation with VEECs, with LGCs expected to decline in value over time and the duration over which they can be created shortens, it is conceivable that it becomes financially more rewarding for new solar systems register to create ACCUs instead of being accredited to create LGCs.

We assume that such systems would only be eligible for ACCU's for generation which was self-consumed and not exported.

At present the framework around how the Safeguard Mechanism will be restructured is still to be determined in detail, therefore the future price of ACCUs is difficult to predict. We have made a simplifying assumption that the ACCU price begins at around $24 in 2023 (which we estimate is roughly in line with the likely floor price for suppliers wishing to exit Emission Reduction Fund fixed deliver contracts) and ascends progressively over the next two decades to a level in line with the International Energy Agency's Announced Pledges scenario.

# 4. Payback periods and modelling approach - behind the meter systems

As noted earlier, the lack of a suitably large and representative sample set of solar system installations, stretching back over several years, prevents the development of a robust quantitative evaluation of how solar system uptake is likely to change in response to changes in the financial attractiveness of solar systems. Nonetheless changes in payback periods provide a useful benchmark or guidepost to inform how future mid-scale solar uptake might unfold.

We have attempted to evaluate how uptake of behind the meter solar is likely to change by assessing payback periods on solar systems in 2023 to 2027 relative to a baseline of the 2019 and 2020 years. Given the noticeable lags affecting the mid-scale solar market we believe 2019 and 2020 installation levels are a reasonable reflection of the likely sustained customer solar uptake in response to the large electricity price and system cost changes that unfolded over 2016 to 2018.

The number of solar system applications for accreditations in 2019 and 2020 by state are used as our reference or benchmark for evaluating how changes in payback relative to these years will change uptake of LGC registered behind the meter solar capacity. This is a slight change from prior projections prepared for the CER which used the accreditation date rather than application date for assessing how many systems and capacity were installed in the benchmark year. Application date is now used because it provides a more accurate representation of the date in which a system installation took place.

To provide a lower bound guidepost as to how much capacity accredited could fall as paybacks deteriorate (become longer), we've used 2016 installation levels as a benchmark which we assume were a product of payback periods based on 2015 market prices. While it varies between states and customer-types, payback periods based on 2015 market conditions were more than twice as long as what they were in 2019/20. Mid-scale behind the meter solar capacity accredited in 2016 (excluding remote or off-grid power) was 22MW. As a further refinement in this year's analysis we've also made use of the 2022 year to July level of accreditation application levels as a another guidepost for how installs could change in response to changes in payback. It is assumed the purchasing decision for these systems was informed by 2021 paybacks.

With these three reference points we have constructed an uptake curve that estimates how the capacity of behind-the-meter solar installs are assumed to change as paybacks lengthen. Both uptake and paybacks are referenced relative to 2019 and 2020 levels. So, if the payback period in a future year was the same as this time (a value of 1) then the capacity accredited would be the same, or 100%, of what it was on average over 2019 and 2020. If the payback period is twice as long as what it was in 2019/20 then uptake is assumed to drop down, although not quite as low as what it was in 2016.

However, on top of the payback evaluation we also overlay an underlying growth factor to account for the fact that:

- the solar industry is expected to become more capable and competitive in the sale and installation of solar systems; and
- customers have growing understanding and confidence with solar systems' ability to reduce electricity costs.

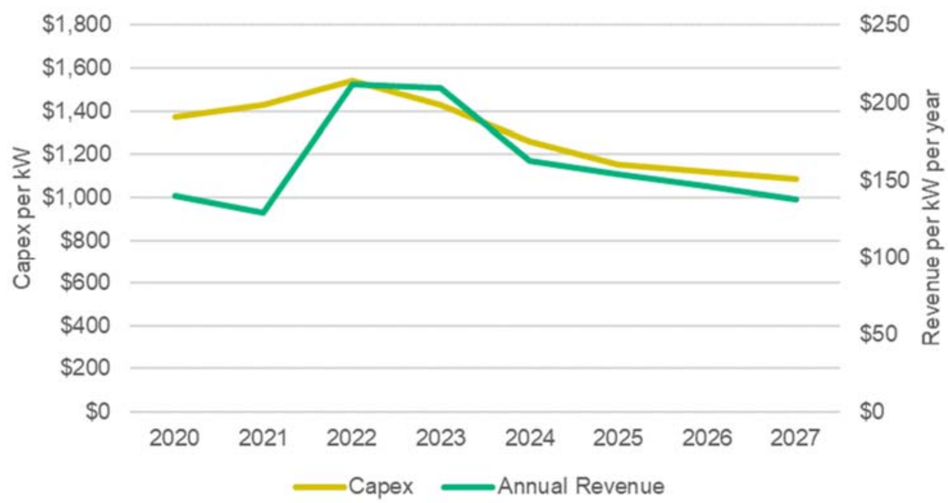
This growth factor steadily increases the baseline capacity that will be induced by given payback. This is set at an increase of 6% per annum.

The uptake curve is structured in such a way that once paybacks lengthen beyond 1.5 times 2019 levels, then uptake becomes less sensitive to lengthening payback. This is based on feedback from industry participants and observations of the market that suggest there is an underlying level of demand for solar installations that is heavily driven by non-financial motivations. This source of demand is much less sensitive to payback periods. But as payback shortens from 1.5 times 2019 levels then uptake accelerates, which is consistent with the rapid growth the market experienced from 2016 to 2018. Unfortunately, we do not have any experience to draw from to understand how uptake might respond if paybacks were to noticeably improve/shorten relative to 2019/20 levels. Our current hypothesis is that uptake would accelerate noticeably as payback moved towards a halving from 2019/20 levels. This is because at such a point solar would provide such a rapid payback that most businesses would find it attractive to install. However as noted earlier, given the lack of historical experience and the small sample of systems installed to date our estimates of uptake responsiveness are highly uncertain.

**Perceived payback periods expected to shorten in next few years in NEM due to spike in wholesale power prices but then lengthen due to drops in daytime wholesale market prices**

In the figure below we have detailed how capital cost and revenue per kilowatt of solar capacity unfold over the projection period for NSW.

**Figure 4-1 Capital cost and revenue per kilowatt for NSW system**

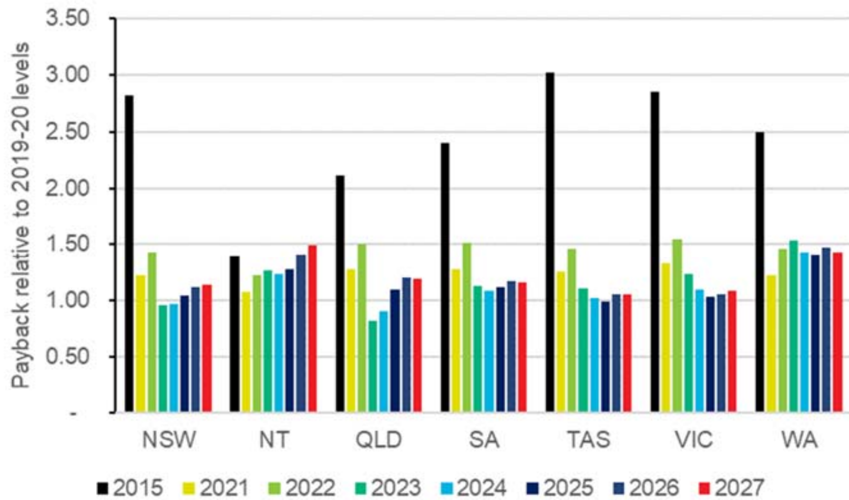



As shown in the green line, revenue (or electricity costs saved) for a solar system is expected to spike upwards from about $150 per annum per kilowatt in 2021 to slightly above $200 per kilowatt in 2022 (which will feed into uptake in 2023). It then holds at this level for 2023 before a rapid fall in 2024 and then smaller but steady progressive declines over the next few years to 2027. Similar patterns occur for the other states. Solar system capital cost rises between 2020 and 2022 but then is expected to resume its prior historical trajectory of steady cost reductions.

Figure 4-2 details how estimated customer-perceived payback periods in 2021 to 2027 compare relative to what they were in 2019/20 based on our modelling assumptions. Note that the scale is not the payback period in years but rather the length of the payback relative to, or divided by, what it was in 2019/20. So if the value is exactly 1 it means the payback period has remained the same as it was in 2019/20 in that state. If the value is 2 then it means the payback period is twice as long as what it was in 2019/20.  As explained earlier, to provide a reference point of possible lower-bound uptake we've also analysed likely paybacks under 2015 market conditions relative to 2019/20 which are also illustrated in Figure 4-2.

Note that these paybacks below are not the actual payback but rather the payback as we expect a customer will perceive it based on the myopic purchasing decisions explained in section 2. This means they evaluate payback based on prices prevailing only in the current year and the prior year rather than a forecast of future power prices over the life of the solar system. For 2022 we also made a further adjustment that energy consumers would not have anticipated the very large increase in electricity costs that has unfolded and so the perceived payback in 2022 is based solely on electricity market conditions prevailing in 2021.

**Figure 4-2 Changes in perceived payback period by state relative to 2019/20 level**
*2019/20 payback period assigned value of 1*




For the NEM-based states, after the deterioration (paybacks become longer) in perceived payback periods in 2021 and 2022, there is dramatic improvement in 2023 as potential purchasers of solar take into account the huge rises in wholesale energy costs that unfolded over 2022. However, paybacks then begin to lengthen due to the expectation that wholesale power prices will fall from their current highly elevated levels. Also while capital costs begin falling again over this period, this is somewhat counteracted by the declining value that can be captured from LGCs due to the declining time period over which they can be claimed (LGCs can only be claimed up to 2030).

# 5. Uptake projections

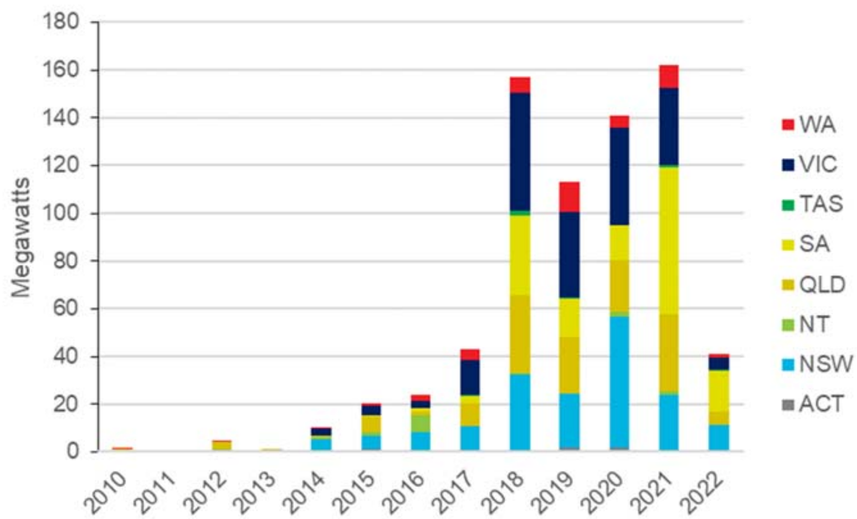
Uptake in megawatts of capacity have been developed for mid-scale solar according to three separate segments which each involve a different set of analysis to estimate uptake:

1. Systems installed on electricity consumers' premises in a behind the meter configuration (where the generation can be self-consumed to offset the need to purchase power from the grid at the retail-delivered price of electricity)
2. Systems installed as power plants in front of the meter which are dependent on revenue tied to the value of the wholesale electricity market; and
3. Systems installed in remote or off-grid power systems where their primary benefit is to reduce gas and diesel fuel use to supply power.

## Behind the meter solar systems

Figure 5-1 details the history of megawatts installed in behind the meter applications that were registered to create LGCs.

**Figure 5-1 Capacity of behind-the-meter systems by year of application**




*Note: 2022 numbers are only up to July. Based on historical patterns these can be expected to represent 60% of full year figures. Some of the capacity within this chart incorporates projects which have applied for accreditation but are yet to be accredited. For these projects, as well as those accredited, capacity is recorded against the year in which the application was received.*

The projected future capacity of behind the meter systems is estimated based predominantly on changes in payback periods relative to 2019 and 2020 levels, as explained in section 4 of this report, with adjustment for an industry and customer capability growth factor. However, we then apply a second pass to the projected numbers to account for significant solar roll-out initiatives that have been publicly disclosed and larger systems that we are aware of that are in the process of being constructed or tendered.

Megawatts expected to be installed behind the meter in the base case are detailed in Table 5-1 below.

**Table 5-1 Projected megawatts registered – Behind the meter**

| State/Territory | 2023 | 2024 | 2025 | 2026 | 2027 |
|---|---|---|---|---|---|
| ACT&NSW | 50 | 53 | 52 | 34 | 34 |
| NT | 0.9 | 1.0 | 1.0 | 0.8 | 0.8 |
| QLD | 36 | 33 | 29 | 22 | 26 |
| SA | 13 | 15 | 14 | 14 | 14 |
| TAS | 1.1 | 1.4 | 1.5 | 1.4 | 1.4 |
| VIC | 35 | 35 | 38 | 37 | 37 |
| WA | 4 | 36 | 6 | 6 | 6 |
| **TOTAL** | **140** | **174** | **142** | **116** | **120** |

A number of adjustments have been made to these numbers to reflect information about specific organisations' solar initiatives.

Firstly we assume that SA Water Corporation's Project Zero initiative to roll-out 154 megawatts of solar across a large number of its sites will be fully complete by 2022 and so none of those projects affect installation numbers in 2023 or later. We also assume that the large solar systems being installed at the Robertson Barracks and Darwin RAAF Air Base (based in the Northern Territory) are accredited in 2022 and so are left out of these projections.

WA jumps up suddenly in 2024 due to an assumption that the Homestead Mine Site Solar Farm or Kalgoorlie Power Hub proceeds to construction and is accredited at this point.

NSW's numbers are also adjusted upwards across 2023 to 2025 to take into account a boost in installation levels as a result of the NSW Government's initiative to install 40MW on government sites by 2024.

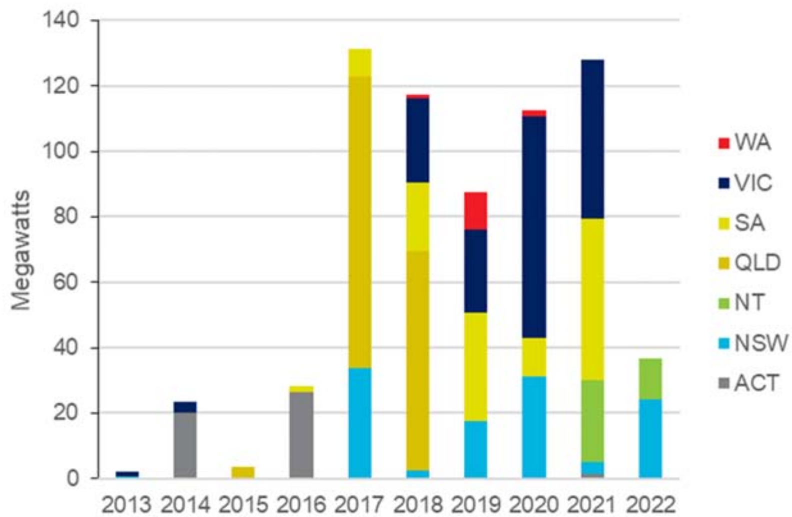
Victoria's 2023 numbers are also adjusted upwards to incorporate capacity from the Winneke Treatment Plant Solar Farm, while the other solar farm being constructed at Eastern Treatment Plant is assumed to be accredited in 2022.

### In front of the meter power plants

In front of the meter power plants are solely dependent on the wholesale market for electricity market revenue and tend to be much larger in scale, while smaller in aggregate number. Consequently, we have used a bottom-up approach to estimating their future uptake, solely dependent on feedback from industry participants.

Since solar became an economically competitive option for deployment in front of the meter, developers have favoured quite large plants, typically 50MW or larger in scale. This has been partly a function of lower construction costs, but the major reasons were financier preferences for larger transaction sizes to minimise due diligence effort, and maximising returns for developer effort in the planning approval process. Figure 5-2 details annual capacity installations for power stations below 30MW back to 2013.

**Figure 5-2 Capacity of sub-30MW power stations by year of application**




So far this segment has been a relatively minor portion of overall solar farm power station solar capacity additions, but is a very significant part of the mid-scale solar market. Over the last few years we have seen the emergence of a number of developers specialised in developing and building solar farms close to 5MW (in terms of their alternating current output rating) in size, which are not subject to a range of AEMO's system management and grid connection obligations. The most significant of these is Providence Asset Group, although often the project will be taken through planning and construction by another firm before being transferred to Providence once it achieves planning approval or construction completion.

Our evaluation of the economics of these plants - based on an expectation of large falls in wholesale power prices during daylight hours - suggests they are not financially viable, or at least would rationally be delayed until batteries drop considerably in cost or a longer-term emissions reduction policy framework was enacted.  Therefore, one should logically expect installation levels to fall to zero.

However, given these projects continue to be committed to construction over the last few years, clearly a number of companies have a more optimistic perspective about daytime wholesale power market prices and the long term value of abatement certificate entitlements (such as LGCs) than GEM.

Table 5-2 details the amount of megawatts that feedback from developers and solar equipment suppliers suggests is reasonably likely in the sub-30 megawatt range. Feedback suggests that these plants are unlikely to exceed 5MW (AC rated capacity). It is important to note that there is large room for error in these estimates. This is because projects can come in sizable lots of 5 MW per project (and potentially as large as 30MW per project), so it doesn't take much of a change in the number of projects proceeding for there to be a large change in the megawatts of capacity accredited. Also, there may be developers that are well progressed with projects that we are unaware of because projects of this scale do not need to pass through state government level approval processes, and can escape media attention. On the downside, there are plenty of hurdles that might stall or halt projects that industry participants fail to anticipate and mean ultimate accreditations fall short of the estimates below.

**Table 5-2 Projected megawatts registered – Power stations (AC-rated)**

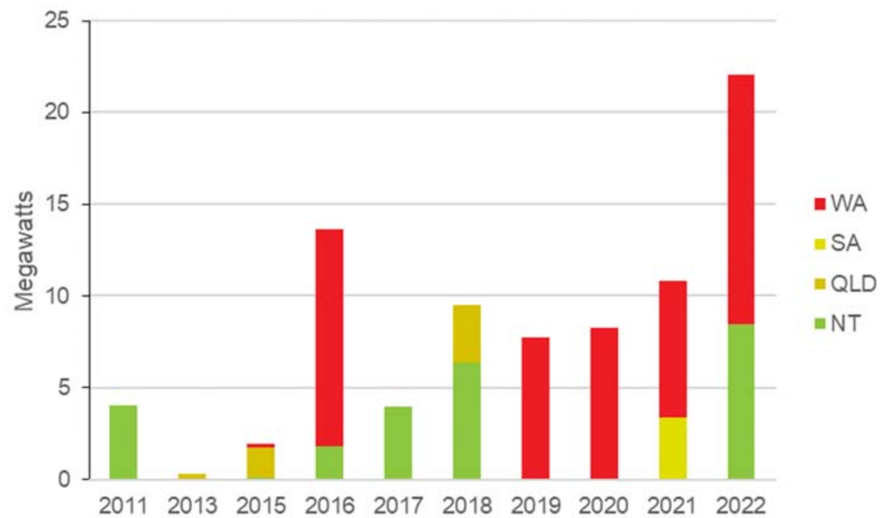
| State/Territory | 2023 | 2024 | 2025 | 2026 | 2027 |
|---|---|---|---|---|---|
| ACT&NSW | 69 | 45 | 35 | 20 | 20 |
| NT | 0 | 0 | 0 | 0 | 0 |
| QLD | 0 | 10 | 15 | 10 | 0 |
| SA | 5 | 10 | 0 | 0 | 0 |
| TAS | 0 | 5 | 10 | 5 | 5 |
| VIC | 36 | 20 | 20 | 15 | 15 |
| WA | 0 | 5 | 5 | 5 | 5 |
| **TOTAL** | **111** | **95** | **85** | **55** | **45** |

The capacity levels in 2023 and 2024 are almost entirely a function of specific individual projects or company roll-outs which have been already been announced. Numbers from 2025 onwards are a mixture of specific announced plans by companies and feedback from interviews about what level of future construction activity is reasonably likely.

### Remote/Off-grid power systems

While the economics of solar displacing diesel in remote power applications have appeared to be attractive for many years, to date the capacity of mid-scale solar systems accredited for LGCs in remote power applications has been modest.

**Figure 5-3 Capacity of remote/off-grid solar systems by year of application**




However, in the last 2 years we have seen significant project commitments in this space as well as announcements from major off-grid system operators to increase the use of renewables. These indicate solar has reached a critical inflection point where its economics and demonstrated technical performance suggest installations could rise significantly relative to the past.

However, it is critical to note that viability is conditional on the customer for the power being able to make a 10 year commitment to purchase the power in order to justify the significant upfront investment involved in deploying solar. For many mine sites a ten-year commitment is difficult because of either volatile prices for their mined product, or because the economically recoverable resource may be exhausted within that timeframe. Also, some sites may have contracts in place with several years until expiry that potentially limit the flexibility or incentive for solar to be deployed. This means that even though solar has been economically attractive, its speed of adoption is constrained.

Last year we scaled-back our projections of installations in the remote/off-grid market due to a significant drop in the oil price as a result of the COVID 19 induced downturn in oil demand. However, oil prices have since substantially recovered. In addition resource commodity prices have also been buoyant supporting new mining activity. Furthermore, it also appears that miners are facing pressure from large institutional investors to reduce their carbon emissions intensity. Lastly major operators of remote power supply systems in Horizon Power, Zenith Energy, Energy Developments and Pacific Energy have all made public statements that they will look to integrate much larger shares of renewables across their sites.

These developments, in conjunction with specific new project announcements, has led us to lift the amount of capacity we are projecting to be installed in the off-grid/remote power market.

Table 5-3 details our estimates of megawatts by accreditation year. These are partially informed by announced system roll-outs by Horizon Power, BHP, EDL, Roy Hill Mine, Zenith Energy and Pacific Energy. Outside of these known initiatives our estimates of future capacity are highly speculative given they are a function not just of solar system economics but also future mining activity. Given the uncertainties afflicting this sector it was not possible to break-this down to state level estimates, although we'd expect the bulk of capacity to be installed in WA, followed by NT and QLD.

**Table 5-3 Projected off-grid/remote system megawatts registered nationally**

| 2023 | 2024 | 2025 | 2026 | 2027 |
|---:|---:|---:|---:|---:|
| 71 | 61 | 50 | 50 | 50 |

## 6. LGC Creation

The tables below provide estimates of projected annual LGC creation for the plant accredited in each year of the projection by each market category. These are not projections of LGC creation in the year indicated but rather the ongoing annual LGCs the capacity accredited in each year indicated can be expected to produce over a full year of operation.

### Behind the meter

Table 6-1 details estimated ongoing annual LGC creation from solar systems installed in a behind the meter configuration. Please note that we anticipate that new behind the meter systems are likely to elect to register ACCUs rather than LGCs from 2026 onwards in NSW, NT and WA and from 2027 onwards for QLD, SA and TAS. In Victoria our model estimates that systems would be better off creating Victorian Energy Efficiency Certificates or VEECs instead of LGCs throughout the outlook period. Although it is worth noting that while VEECs represent a financially superior option, they are also a more administratively onerous one.  Also for those with voluntary abatement commitments, the voluntary surrender of LGCs can represent an easier way of demonstrating compliance. So it's possible that some systems will still elect to create LGCs over 2023 to 2027.

**Table 6-1 Annual ongoing LGCs by year of plants' accreditation**

| State/Territory | 2023 | 2024 | 2025 | 2026 | 2027 |
|---|---|---|---|---|---|
| ACT&NSW | 66,239 | 69,071 | 68,190 | ACCUs | ACCUs |
| NT | 1,350 | 1,426 | 1,503 | ACCUs | ACCUs |
| QLD | 46,775 | 43,720 | 38,052 | 29,240 | ACCUs |
| SA | 16,807 | 19,848 | 18,710 | 18,710 | ACCUs |
| TAS | 1,323 | 1,644 | 1,767 | 1,645 | ACCUs |
| VIC | VEECs | VEECs | VEECs | VEECs | VEECs |
| WA | 5,879 | 48,326 | 7,998 | ACCUs | ACCUs |
| **TOTAL** | **138,373** | **184,035** | **136,219** | **49,595** | **0** |

*Note this is intended as an approximate average of annual LGC creation, panel degradation means in reality output and therefore LGCs will decline slowly over time as systems age.*

### In front of the meter power stations

In front of the meter power stations are understood to be unable to create either ACCUs or VEECs based on the existing available methodologies for certificate creation and so new systems continue to register to create LGCs. Table 6-2 details expected annual average LGC creation for this segment.

**Table 6-2 Annual ongoing LGCs by year of plants' accreditation**

| State/Territory | 2023 | 2024 | 2025 | 2026 | 2027 |
|---|---|---|---|---|---|
| ACT&NSW | 145,675 | 94,608 | 73,584 | 42,048 | 42,048 |
| NT | 0 | 0 | 0 | 0 | 0 |
| QLD | 0 | 21,024 | 31,536 | 21,024 | 0 |
| SA | 10,512 | 21,024 | 0 | 0 | 0 |
| TAS | 0 | 9,198 | 18,396 | 9,198 | 9,198 |
| VIC | 70,324 | 38,544 | 38,544 | 28,908 | 28,908 |
| WA | 0 | 10,512 | 10,512 | 10,512 | 10,512 |
| **TOTAL** | **226,511** | **194,910** | **172,572** | **111,690** | **90,666** |

*Note this is intended as an approximate average of annual LGC creation, panel degradation means in reality output and therefore LGCs will decline slowly over time as systems age.*

### Remote/Off-grid power systems

Remote/Off-grid power systems are assumed to be treated as equivalent to power stations and are therefore interpreted to be ineligible to create ACCUs based on the existing available methodologies and so new systems continue to register to create LGCs.

Table 6-3 details expected annual average LGC creation from capacity installed in this segment.

**Table 6-3 Annual ongoing LGCs by year of plants' accreditation**

| 2023 | 2024 | 2025 | 2026 | 2027 |
|---|---|---|---|---|
| 106,394 | 90,514 | 74,460 | 74,460 | 74,460 |

*Note this is intended as an approximate average of annual LGC creation, panel degradation means in reality output and therefore LGCs will decline slowly over time as systems age.*