Mid-scale solar outlook 2020 to 2025
Systems above 100kW to 30MW

Report to the Clean Energy Regulator

Final Report
September 2020

Green Energy Markets
G.02 109 Burwood Road Hawthorn VIC 3122
T: 03 9805 0777
admin@greenmarkets.com.au
www.greenmarkets.com.au

Blank page

Table of Contents

Disclaimer
The data, analysis and assessments included in this report are based on the best information available at the date of publication and the information is believed to be accurate at the time of writing. Green Energy Markets does not in any way guarantee the accuracy of any information or data contained in this report and accepts no responsibility for any loss, injury or inconvenience sustained by any users of this report or in relation to any information or data contained in this report.

Blank page

1. Executive Summary

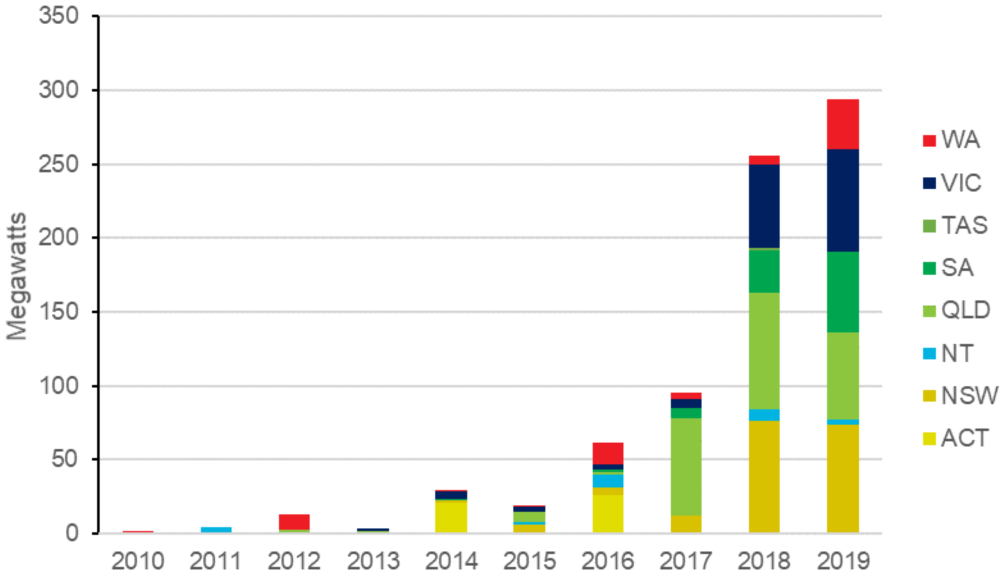
Green Energy Markets has been commissioned by the Clean Energy Regulator to provide a projection of levels of mid-scale solar capacity installed by year for the period of 2020 to 2025. Mid-Scale capacity is defined as solar systems above 100 kilowatts and up to 30 megawatts[1]. The projection covers:

- 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.

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.

The market has only really emerged at any noticeable level in the last four years 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.

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



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. This capacity has already 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 are now close to record lows over daytime periods and this is expected to extend to other states (with the exception of NT which does not yet have an effective functioning wholesale market) over the next two years. This will noticeably reduce the revenue gain (or avoided electricity cost) solar systems provide.

[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.

In addition measures to contain the COVID19 virus pandemic have led to a large drop in global demand for oil-based products which has led to large declines in the price of oil with flow-on impacts to the price of diesel and gas which solar systems compete against.

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;
- bottom-up research identifying near-term, significant solar roll-out plans by large organisations such as supermarkets, shopping centre operators, airports, water companies, and government entities.
- financial modelling of the payback periods for investing in solar systems across different states. Uptake in 2021 to 2025 is calibrated against uptake and payback periods for two reference years – 2019 and 2015. Given expected large falls in the wholesale market value of electricity, it is expected paybacks will deteriorate (become longer) relative to 2019 electricity prices. Therefore the amount of capacity installed would be expected to decline. The extent of the decline is guided against how much paybacks deteriorate relative to what they were in 2015, which provides a type of bottom-end guidepost. However, the financial modelling provides a baseline of indicative projected installations over the period to 2025 but 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	2020	2021	2022	2023	2024	2025
ACT&NSW	122	158	60	60	72	70
NT	59	1	1	1	0	1
QLD	31	40	28	30	33	41
SA	72	192	12	13	24	26
TAS	0.4	0.6	0.6	0.6	0.7	0.8
VIC	57	95	101	60	60	67
WA	39	44	14	12	12	12
Off Grid - all states	9	5	14	13	15	20
TOTAL	**390**	**535**	**231**	**189**	**218**	**236**

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 from 2022 onwards 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 or Australian Carbon Credit Units in other states.

Table 1-2 Expected annual ongoing LGC creation by year of plants' installation

State/Territory	2020	2021	2022	2023	2024	2025
ACT&NSW	244,019	315,818	23,652	23,652	47,304	47,304
NT	136,854	1,054	1,054	0	0	0
QLD	43,664	73,750	0	0	0	0
SA	156,703	314,633	0	0	23,652	23,652
TAS	524	756	0	0	0	0
VIC	90,594	170,003	22,776	22,776	22,776	22,776
WA	89,015	96,453	22,869	0	0	0
Off Grid - all states	14,664	8,350	22,481	20,876	24,087	32,116
TOTAL	**776,038**	**980,819**	**92,833**	**67,304**	**117,819**	**125,848**

2. Overview of the Market

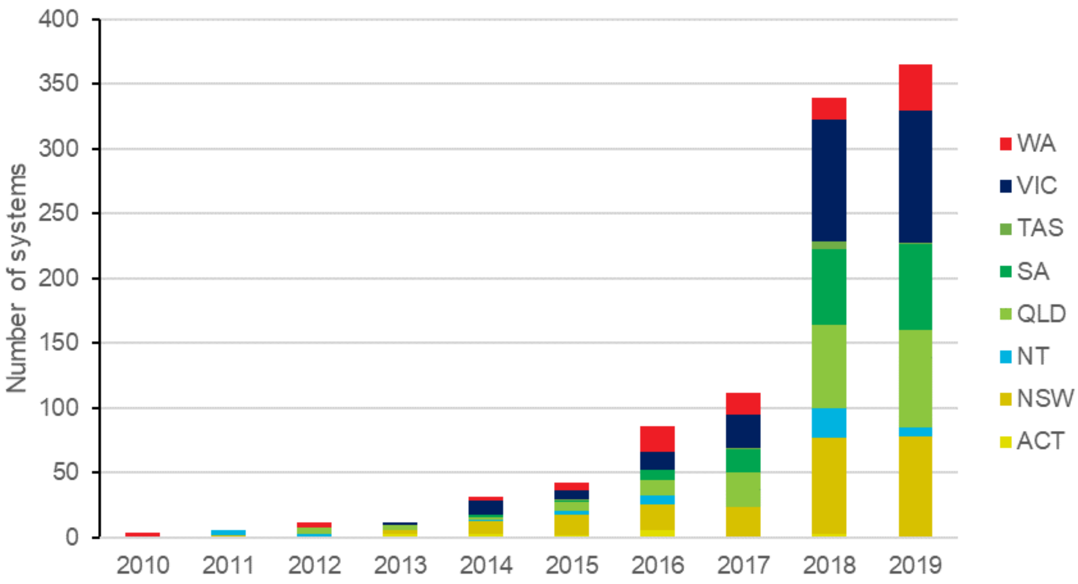
The mid-scale solar market has undergone considerable flux and is subject to significant uncertainty

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 in reality highly 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 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.

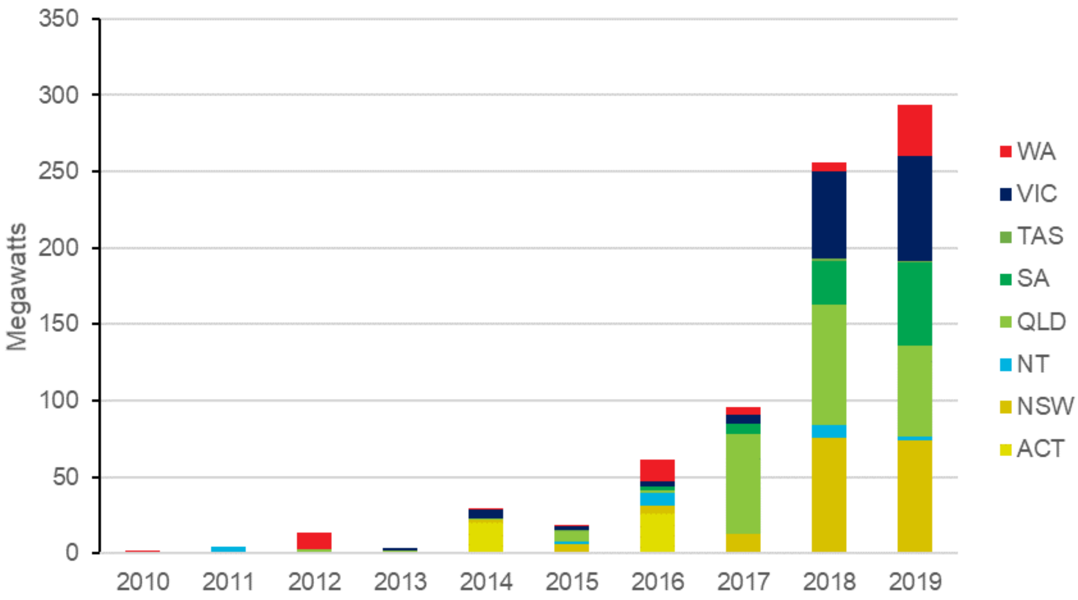
Figure 2-1 Number of mid-scale solar systems by year of accreditation (up to 30MW)



Megawatts of generating capacity, shown in Figure 2-2, have followed a similar trajectory to the number of systems.

[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 2-2 Capacity of mid-scale solar systems by year of accreditation (up to 30MW)



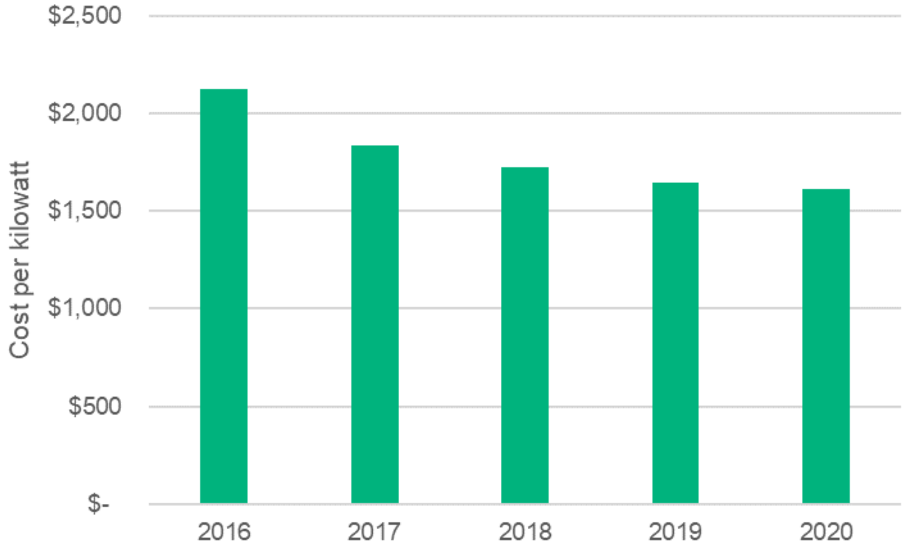
The small numbers of installations until just recently means there is a scarcity of historical data with which to assess statistical relationships between uptake and possible causes of increased uptake that might facilitate precise quantitative analysis.

Rapid growth in mid-scale has been spurred by a dramatic improvement in solar system financial attractiveness

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 market's rapid growth since 2016 was predominately a function of improving 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.

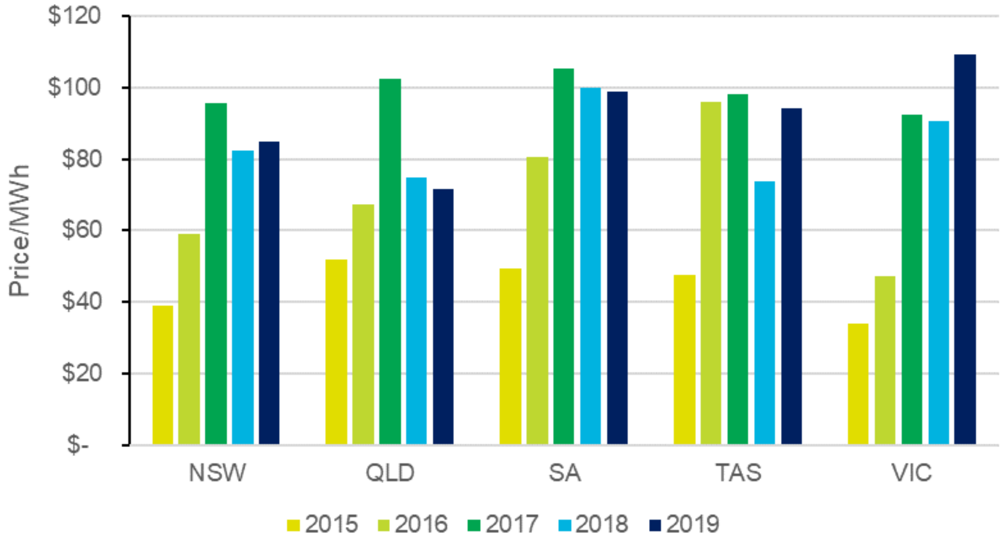
Figure 2-3 Cited installed cost of mid-scale systems per kilowatt by year (excluding off-grid/remote grid systems)



Note: 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 as shown in Figure 2-4. The jump in prices began in 2016 but was greatest in 2017 for NSW, QLD and Victoria.

Figure 2-4 Average time-weighted wholesale electricity spot price by state

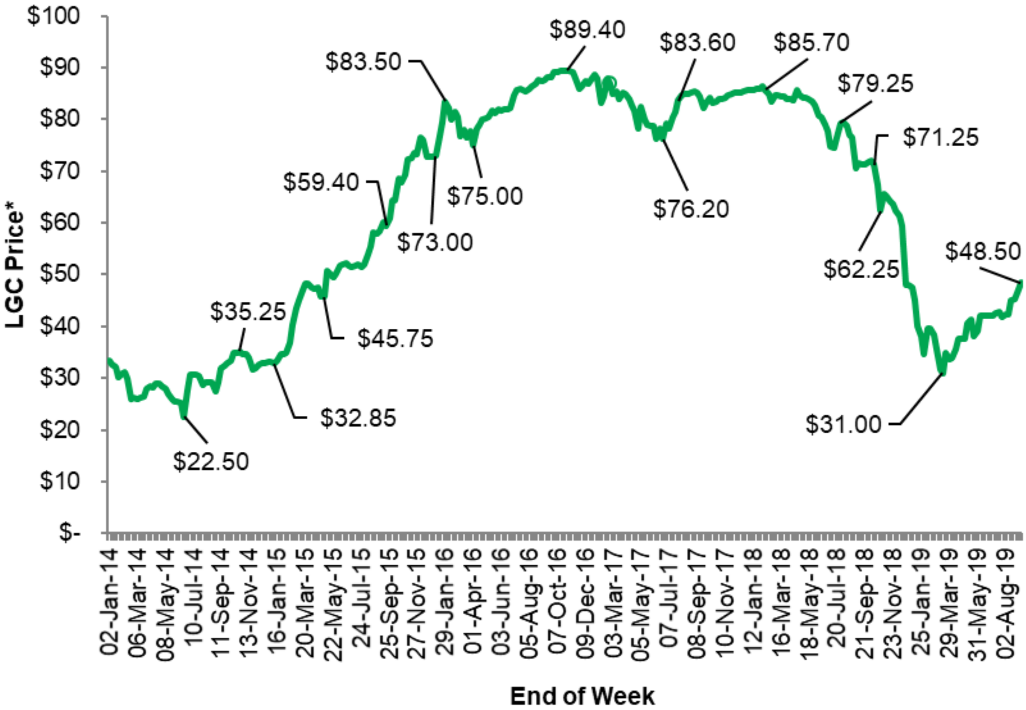


For customer sites potentially suitable for behind the meter systems larger than 100kW, changes in wholesale market energy prices have a far greater impact on kilowatt-hour charges than for smaller customers such as the residential market (whose network charges are recovered based on consumption of kilowatt-hours).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

shown in Figure 2-5. LGC prices subsequently collapsed in the last quarter of 2018 but were elevated at close to $80 throughout 2016 and 2017 and much of 2018.

Figure 2-5 LGC spot prices (end of week)



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 roughly halved for a range of customer sites likely to be suitable for 100kW+ behind the meter systems.

Suppliers also became more capable in marketing and installing 100kW+ solar systems

It is important to recognise that Australia's solar industry has traditionally been dominated by selling and installing small, generic solar systems to residential households. Selling and installing such residential systems is usually much simpler than what's required for large commercial systems. Commercial clients have more varied tariff types, need a more tailored approach to system design, take a more involved and sophisticated approach in evaluating whether to purchase solar, are more prone to landlord-tenant split incentives, and the technical requirements of such systems are more difficult, in particular the grid connection process. Another factor that has been more important in the commercial sector than residential has been the provision of financing that avoids the need for clients to commit their own upfront capital to purchasing the system.

As the financial attractiveness of large commercial solar systems has improved and the levels of interest in installing solar has grown, the solar industry has gained much greater experience in the sale and installation of these larger systems. This has allowed them to become better at presenting and explaining the investment proposition for solar to clients involving multiple decision makers and detailed evaluation processes. In addition, they have become more adept at dealing with the needs and concerns of electricity networks, and likewise electricity networks have gained greater comfort and understanding in having 100kW+ solar systems operating within their network. Also financing products have been developed with more attractive terms such as lower interest rates, longer repayment periods, and repayments tied to consumption of electricity from the solar system otherwise known as power purchase agreements.

These have helped to at least somewhat mitigate tenant-landlord split incentives, and the often myopic approach businesses take to allocating capital to non-core elements of their business (a problem of bounded rationality which is a well understood factor behind sub-optimal levels of investment in energy efficiency).

Feedback from industry interviews indicates that more technically sophisticated and experienced commercial sector solar firms have found themselves facing increasing levels of competition and difficulty maintaining margins as they find more firms capable of selling and installing systems above 100kW in scale. One interviewee colourfully reflected, “systems bigger than 100kW used to be confined to technically savvy outfits. But now any old monkey can install up to a 300kW system, with 600kW where they get out of their depth.”

The improved capability and greater spread of capability in installing 100kW+ solar systems has meant customers see not just a lower purchase price for solar systems, but also find the purchase decision making process easier and more compelling. In many cases the decision to purchase solar is not an over-riding priority for a business. Given this, the ability of the solar supplier to develop customer confidence about solar can make a decisive difference.

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. There are several examples of accredited mid-scale projects where this whole process took over 12 months, even though installation may have only taken a month or two.

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. Furthermore, our interviews suggest that systems coming through accreditation now are likely to still be a function of customer responses to the 2017 and 2018 surge in electricity costs.

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. Interestingly interviews suggested that customers evaluating whether to purchase solar in the last few months, 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. This is especially important given both the National Electricity Market and the Western Australian South-West Interconnected System (SWIS) are only now beginning to experience a growing and very substantial surplus of available generating capacity during daytime periods when solar power is generating at significant levels. Unless there are further major coal generator retirements, wholesale electricity prices are going to remain at record low levels over periods when solar system output is high. 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 electricity prices from the prior year were going to remain static in real terms over the life of the solar system or they only consider how prices are likely to evolve over the short-term of around the next three years or the next electricity contract offer.

3. Market conditions and modelling assumptions

Solar system costs anticipated to continue decline steadily

We assume a solar system cost for mid-scale behind the meter, grid connected solar systems of around $1,600 per kilowatt prevailed in 2019 and this dropped to $1,350 per kilowatt in 2020. The cost assumed for 2020 is lower than the data provided from the Clean Energy Regulator's extract of registry data and is heavily informed by interviews with industry participants and also data obtained from other sources.

For future costs we assume the installed cost of a large commercial rooftop system will reach around $890 per kilowatt (2019 dollars) in 2025 with costs aligned with CSIRO's Gencost projection prepared for the Australian Energy Market Operator's 2020 Integrated System Plan[3].

Ongoing cost reductions in the mid-scale sector are expected to be driven by ongoing declines in module prices, but mainly savings in labour and balance of system equipment costs per watt installed through gains in solar module conversion efficiency. This gain in module conversion efficiency allows for more watts to be installed for a given number of modules, with the number of modules installed being a key driver of labour and balance of system costs. The potential to exploit productivity gains remains significant in the mid-scale solar segment where installations can take several days to be completed and sometimes roof space can be a constraining factor.

Cost reductions are assumed to be faster in large commercial sector than what we have assumed for residential systems in our projections of STC systems. This is a function of the fact that large commercial has greater scope to exploit labour productivity gains from improved module conversion efficiency than what can be achieved with residential systems (where networks typically don't allow inverters from exporting more than 5kW to the grid which discourages ongoing growth in system size).

Wholesale electricity market prices are dropping significantly during sunlight hours

A very significant amount of solar generating capacity will be added to both the National Electricity Market and Western Australia's SWIS over 2017 to 2022. This will substantially depress wholesale power prices during daylight periods relative to what was experienced in the past.

In the NEM, Green Energy Markets' power project database has over 8,000MW of LGC-registered solar systems being added to the grid from 2017 to 2022 based on projects already accredited, under construction or with offtake contracts in place. On top of this, STC registered solar systems in the NEM are being added at a rate substantially exceeding a gigawatt per annum on average since 2017. When one adds the large amount of extra wind output likely to coincide with solar generation (7,000MW of wind will also be added between 2017-2022), the residual demand left over for fossil fuel generators over daytime periods should result in substantial oversupply of low operating cost coal capacity. This would appear to replicate oversupply conditions not unlike those that prevailed late at night during 2010 to 2011 when wholesale power prices averaged below $30 per megawatt-hour.

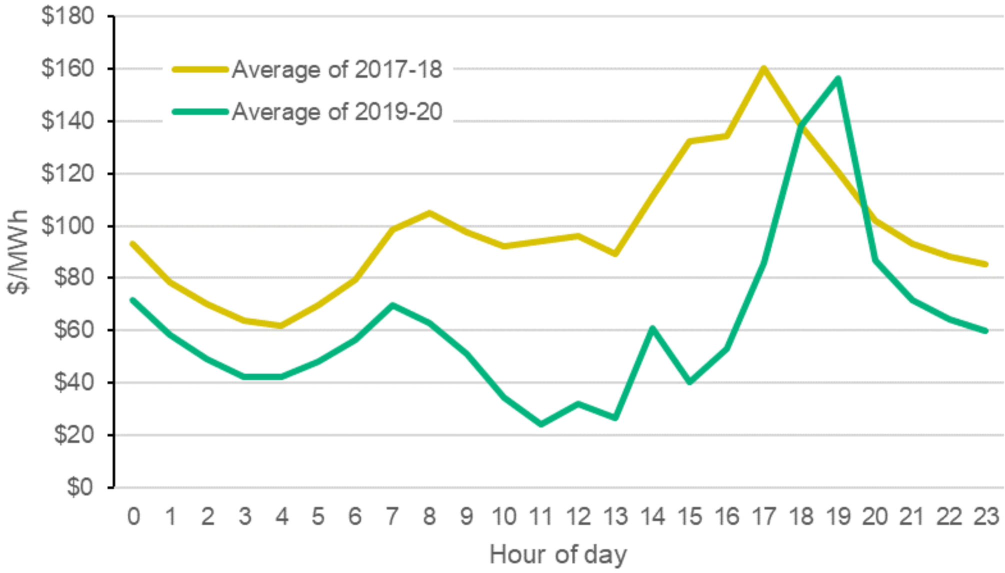
Wholesale power prices in the NEM in recent years have been highly elevated because the price of gas increased considerably, and the closure of Northern and Hazelwood Power Stations provided greater scope for the remaining coal generators to price their output relative to the cost of gas generation. Given the substantial additional supply from solar and wind generators coming on stream, during sunny periods it is likely coal generators will increasingly need to price their output relative to the operating cost of other coal generators, rather than gas plant, in order to be dispatched.

---

[3] CSIRO (2019) GenCost 2019-20: preliminary results for stakeholder review

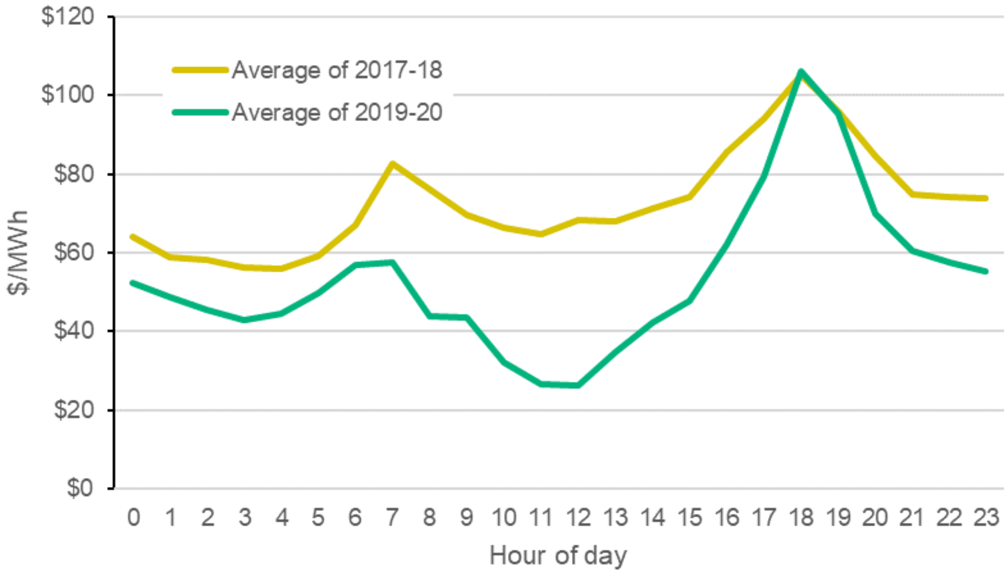
Over the past financial year we are now seeing the depressive impact of the extra solar capacity on wholesale market prices over sunlight hours in the two NEM states with the highest level of solar penetration – Queensland and South Australia. Figure 3-1 illustrates the average wholesale power price in SA by hour of the day for 2017-18 (yellow line) and then for the most recent financial year of 2019-20 (green line). While prices are generally down across all hours of the day for 2019-20 (likely due to much lower gas prices), the difference in prices becomes substantially greater in the hours of highest solar output. Over 10am to 1pm when solar generation is likely to be at its greatest prices are stuck below $40/MWh.

Figure 3-1 Average SA wholesale prices by hour – 2017-18 vs 2019-20



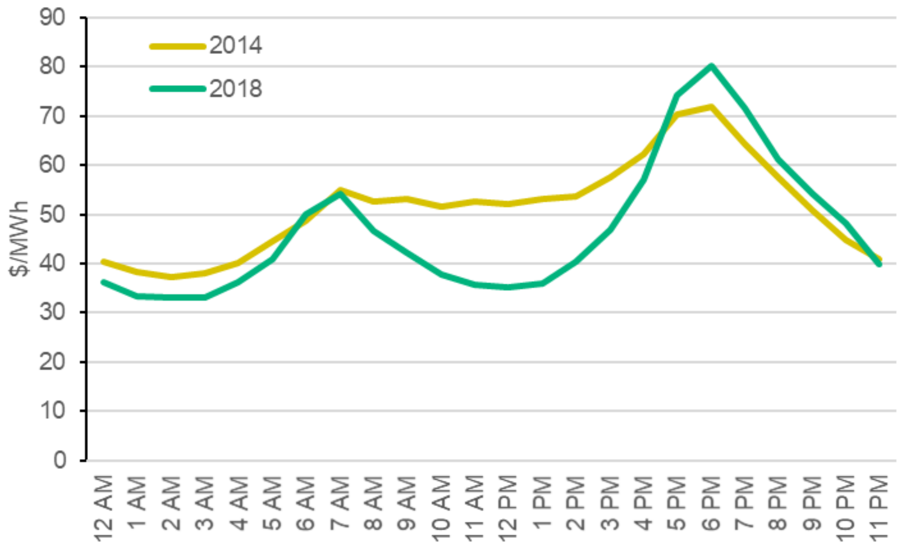
We see almost exactly the same pattern for Queensland wholesale power prices illustrated in Figure 3-2 below.

Figure 3-2 Average QLD wholesale prices by hour – 2017-18 vs 2019-20



Lastly Figure 3-3 shows the same effect of a carving out of prices during sunlight hours in the Western Australian South-West Interconnected System Short-Term Electricity Market with a comparison between prices by hour for 2014 versus 2018.

Figure 3-3 Average WA SWIS STEM prices by hour - 2014 vs 2018



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 to be recovered from NEM 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.

The daylight solar period prices are structured to reflect what we are now seeing in the wholesale markets of SA, Queensland and illustrated in figures Figure 3-1 and Figure 3-2. Our expectation is that other NEM states will soon follow in the footsteps of QLD and SA given Victoria and NSW are experiencing rapid growth in solar capacity and Tasmania's prices will be heavily influenced by those in Victoria.

Queensland customers wholesale energy charge during the solar period is assumed to drop to 4 c/kWh from next year and then remain below 4 cents for the remainder of the outlook. Victoria and NSW's daylight solar energy charge begins much higher but then declines to 4.5 c/kWh by 2025. SA and Tasmanian energy charges are similar to those of NSW and Victoria. Beyond 2025 daylight solar period prices are assumed to be tied to the long run marginal cost of a new entrant solar farm which this cost derived from CSIRO's Gencost projection prepared for the Australian Energy Market Operator's 2020 Integrated System Plan[4]. Feed-in tariffs are assumed to be the same as wholesale energy charges.

NT and WA customers on the other hand are assumed to be charged for energy based on charges that are more smeared across peak and non-peak periods and so see much higher energy charges during the daytime period. WA customers are assumed to pay around 11c/kWh during the daylight period, while NT customers pay 20c/kWh. Smearing is assumed to begin to slowly unwind between 2023 and 2030 such that over

[4] CSIRO (2019) GenCost 2019-20: preliminary results for stakeholder review

the solar daytime period they decline down to the long run marginal cost of a new entrant solar farm by 2030.

LGC prices

LGC prices used for our assessment of paybacks are based on averaged forward prices via reported broker trades over 2020 covering the years of 2020 to 2024 as follows:

- 2020 - $40
- 2021 – $33
- 2022 - $22
- 2023 - $13
- 2024 - $6

For the years 2025 until 2030, where there are no forward trades from which to draw a value, a price of $5 per LGC was assumed.

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. To date no solar system has elected to create VEECs because LGCs have been more financially attractive. However, with the price of LGCs expected to decline significantly over the next few years, creating VEECs from solar is expected to become more financially attractive than LGCs. We assume that all solar systems installed in Victoria from 2022 onwards will elect to create VEECs instead of LGCs. While it is theoretically possible for solar systems to create VEECs now, the industry is still in the process of developing the systems and processes to satisfy the scheme's requirements for creation of VEECs from solar systems.

The Victorian Government is still to finalise the key parameters for the Victorian Energy Upgrades scheme for the period after 2020, in particular the level of the target. However it has released a regulatory impact statement outlining its preferred position and also the anticipated cost of certificates if this position was implemented which is $49.42. Our analysis assumes that the VEEC price holds at its recently traded price of around $34 over 2021 before then rising to $49.42 from 2022 onwards. The amount of emissions displaced by a megawatt-hour of solar generation is derived from NEM emissions detailed in AEMO's December 2019 draft Integrated System Plan.

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 the Emission Reduction Fund lacks clear guidance around how many ACCUs it will seek to acquire over a specific defined timeframe, therefore the future price of ACCUs is difficult to predict. For the purposes of this modelling we have used analysis by Market Advisory Group that suggests a probable price path for ACCUs involves them rising from recent traded prices close to $16 up to $30 by 2030.

Interviews with solar industry participants suggest customer interest in behind the meter solar systems remains strong, in spite of the unfolding downturn in wholesale power prices and LGCs

While it appears likely that wholesale power prices during sunny periods will decline substantially relative to recent times this does not appear to be denting customer interest and demand for large rooftop solar systems. Our interviews with a range of solar industry participants delivered a similar message to last year - customer interest and orders for mid-scale solar systems are at high levels similar or even higher than they were in 2019.

Interestingly, this was even though the economy has suffered an extremely severe contraction as a result of social distancing and travel restrictions to counter the spread of the COVID 19 virus. Interviewees pointed out that a number of the key industries where large rooftop solar systems were an attractive option had not been particularly negatively affected by COVID measures. Supermarkets, large distribution centres operating for online sales, and animal husbandry and food processing have in many cases seen an expansion in sales and while retail has been negatively impacted the very large property trusts that are the typical clients of large rooftop solar systems were already well advanced with their solar roll-outs. This was seen as outweighing the downturn in vulnerable market sectors such as large entertainment and hospitality venues.

As we discovered from interviews undertaken last year, solar installers continue to believe that sales will remain buoyant in spite of the large fall in daytime wholesale energy charges for the following reasons:

- They have achieved further significant savings in equipment and installation costs per kilowatt of capacity.
- A substantial proportion of the kWh price paid by many prospective mid-scale customers was associated with the network charge which is not expected to fall.
- Financing terms for power purchase agreements have improved even further which allow solar suppliers to offer prices for power from solar under PPAs that continue to noticeably undercut the price per kWh that customers face for importing power even if wholesale energy charges were to fall to around 4 c/kWh.
- A significant number of large corporate entities have very well advanced plans for megawatt-scale solar roll-out programs across their facilities which are at such an advanced stage that these companies are unlikely or unable to halt or substantially scale them back.
- A number of potential customers would be on electricity contracts that would not benefit from price declines for another two to three years and so are still to see any decline from what were very high wholesale energy charges over 2017 to 2019;
- Electricity retailers are expected to have difficulty restructuring their pricing offers to deliver discounted prices for consumption during daylight periods, which were significantly more attractive to customers than sticking with more conventional and familiar price offerings that smeared wholesale energy costs across solar and non-solar output periods.
- A number of large corporate clients looking to purchase solar systems were doing it as part of prominent public commitments to reducing their carbon emissions or achieving 100% renewable energy targets. While this point came through in last year's interviews, feedback this year is that this driver has gained substantial momentum. Pressure from investors for companies to demonstrate progress on carbon reduction goals was now evidently flowing through to CFOs and other senior

management. This was pushing the solar purchase decision up the list of priorities for management and allowing solar businesses to break through where a proposal had earlier been stalled. Interestingly, the level of ambition around the scale of the solar roll-outs was also rising as businesses were keen to not just save money, but also do something that would provide an impressive demonstration of their commitment to lowering their carbon emissions.

While these interviews were suggestive of substantial ongoing growth they need to be tempered by an evaluation of the broader market context and data. Our interviews target a small number of the more successful solar businesses and while they represent a large proportion of behind the meter mid-scale capacity accredited to date, they are not a full sample of the experience of the overall market. Also, while interviewees felt the COVID 19 economic contraction had not blunted overall interest, the impacts of the economic downturn are probably still to fully flow-through to consumers and industries likely to suffer indirect impacts but who were not directly affected by travel and social interaction restrictions..

The overall system accreditation numbers so far this year do not show a clear sign of growth on last year's numbers. The monthly average megawatts accredited to June last year was 11.7MW while this year it has been running at 11.8MW. However, what these interviews do indicate is that mid-scale behind the meter market appears to be able likely to hold-up, at least in the short-term, in spite of the significant headwinds from declining daytime wholesale energy prices and COVID-19.

Viability of batteries remains elusive but likely within the outlook period

We heard exactly the same message from interviews this year as last year. Battery systems are not falling noticeably in price and they do not yet represent a financially attractive proposition. Nonetheless interest remains high and solar businesses are alert to the fact that the batteries could greatly enhance the value proposition of solar by addressing the following issues:

- Improving the probability of lowering customers' network demand charges by firming-up the solar generation;
- A solar system's economics rapidly deteriorate once they reach a size where they exceed on-site demand due to the lower value available for exported generation or even the inability to export at all (due to network connection controls). A battery can soak up this excess generation for the site to use at a later time when solar output has fallen below the load of the site.
- that solar generation is now increasingly likely to co-incide with periods of low wholesale market prices, yet much higher prices will prevail within just a few hours of solar generation subsiding.

Several market participants remain of the opinion that the cross-over point for batteries becoming an attractive proposition for customers was within sight. Our analysis suggests that by around 2024 to 2025 the paybacks on battery coupled solar system will be close enough to that of a solar system in isolation that batteries will become an attractive proposition to large commercial customers. However, they don't deliver a payback that is noticeably shorter than electing to purchase a solar system alone. Therefore, we don't expect over the outlook period to 2025 that batteries will act to noticeably increase solar system sales.

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 2021 to 2025 relative to a baseline of the 2019 year. Given the noticeable lags affecting the mid-scale solar market we believe 2019 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.

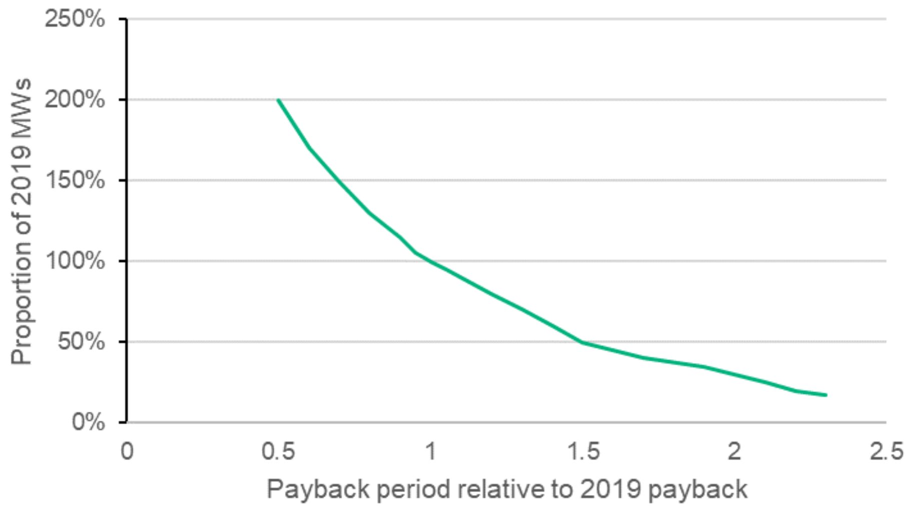
Our analysis of the solar systems accredited in 2019 suggests that around 147MW was behind the meter. These levels become our reference or benchmark for evaluating how changes in payback relative to 2019 will change uptake of LGC registered behind the meter solar capacity.

We expect that paybacks over the next few years will be longer than they were in 2019 for most states across most of the outlook period. 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 roughly twice as long as what they were in 2019 (in Victoria and NSW it was about 2.5 times as long, in Queensland and WA it was closer to 1.5 times longer than 2019 levels). Mid-scale behind the meter solar capacity accredited in 2016 (excluding remote or off-grid power) was 22MW or 15% of the capacity we expect to be accredited in 2019.

With these two reference points we have constructed an uptake curve shown in Figure 4-1, which illustrates the degree to which the amount of behind-the-meter solar is assumed to change as paybacks lengthen. Both uptake and paybacks are referenced relative to 2019 levels. So, if the payback period in a future year was the same as 2019 levels (a value of 1) then the capacity accredited would be the same, or 100%, of what it was in 2019. If the payback period is twice as long as what it was in 2019 then uptake is assumed to drop down, although not quite as low as what it was in 2016. This is because the solar industry is more capable at selling solar systems than what it was in 2015 and 2016 and customers have greater familiarity and comfort with solar systems. Consequently, installs are anticipated to drop to 30% of 2019 levels rather than 15%.

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 levels. Our current hypothesis is that uptake would accelerate noticeably as payback moved towards a halving from 2019 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.

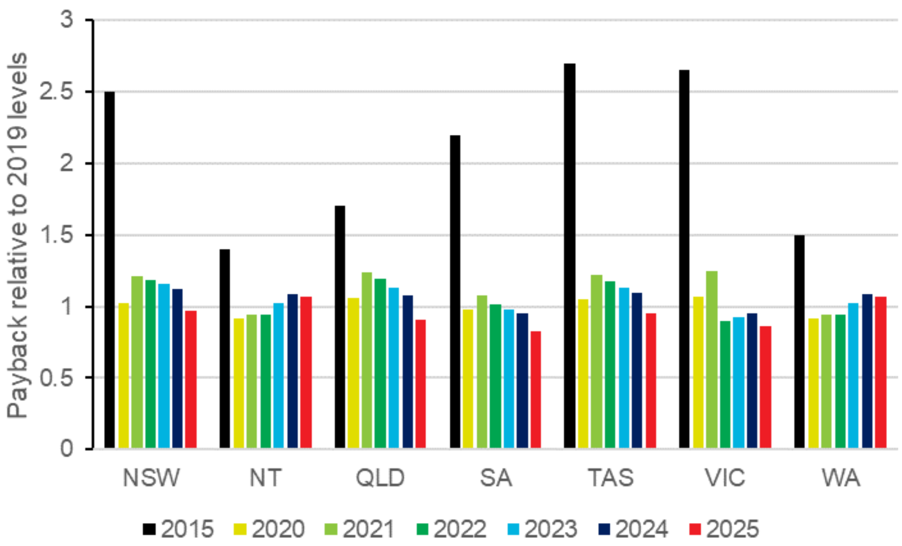
Figure 4-1 Uptake of solar in response to changes in payback periods – relative to 2019 levels



Payback periods expected to initially lengthen due to drops in daytime wholesale market prices but then shorten as system costs decline

Figure 4-2 details how estimated payback periods in 2020 to 2025 compare relative to what they were in 2019 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. So if the value is exactly 1 it means the payback period has remained the same as it was in 2019 in that state and that customer usage/tariff profile. If the value is 2 then it means the payback period is twice as long as what it was in 2019. 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 which are also illustrated in Figure 4-2.

Figure 4-2 Changes in payback period by state and site type relative to 2019 level
2019 payback period assigned value of 1



For the NEM-based states payback periods noticeably deteriorate (become longer) in 2021 relative to 2019 levels due to our assumption that the cost of a kWh of electricity consumed during the daytime solar tariff period drops significantly. Another important factor increasing the length of payback is the assumed fall in the LGC price and the declining time period over which LGCs can be created. Paybacks then tend to steadily improve in the years after 2021 which is largely a function of assumed declines in system costs. In the case of Victoria however there is a sudden improvement in payback in 2022 – this is based on an assumption that systems from this year onwards begin to claim Victorian Energy Efficiency Certificates (VEECs) rather than LGCs which act to significantly boost their revenue.

For WA and the NT their paybacks initially improve relative to 2019 levels based on an assumed drop in system costs while the cost of imported electricity is assumed to remain steady. Paybacks then steadily lengthen each year in these states. This is due to an assumption that their tariffs move towards time of use structures where daytime prices are lower while late afternoon and early evening prices are higher which reduces the amount of savings a solar system can deliver.

5. Uptake projections

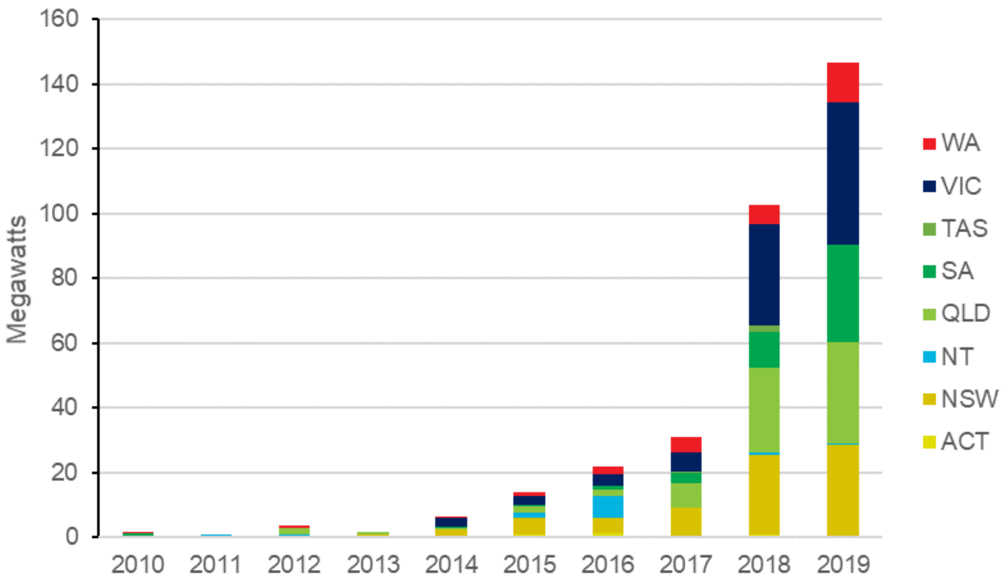
Uptake in megawatts of capacity have been developed for mid-scale solar according to three separate segments which each involve a different set of analysis to estimate uptake:

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 accreditation



The projected future capacity of behind the meter systems is estimated based predominantly on changes in payback periods relative to 2019 levels as explained in section 4 of this report. However, we then apply a second pass to the projected numbers to account for significant solar roll-out initiatives that have been publicly disclosed (e.g. SA Water Corporation) 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 are detailed in Table 5-1 below.

Table 5-1 Projected megawatts registered – Behind the meter

State/Territory	2020	2021	2022	2023	2024	2025
ACT&NSW	48	61	50	50	52	50
NT	14	0.7	0.7	0.5	0.5	0.5
QLD	31	25	28	30	33	41
SA	17	167	12	13	14	16
TAS	0.4	0.6	0.6	0.6	0.7	0.8
VIC	42	47	91	50	50	57
WA	7	14	14	12	12	12
TOTAL	**157**	**316**	**197**	**156**	**163**	**176**

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

The most significant is SA Water Corporation's Project Zero initiative to roll-out 154 megawatts of solar across a large number of its sites. We have assumed almost of all the planned systems to be rolled out will be accredited in 2021, which is the reason why South Australia's accredited capacity blows out to such a large amount in that year before then collapsing to a much lower amount in 2022.

Victoria experiences a noticeable uptick in capacity in 2022 which is a function of two things:

- An underlying and permanent improvement in financial payback as a result of an assumption that the industry becomes equipped and capable of creating VEECs instead of LGCs;
- A one-off adjustment upward to capture the expected completion of two 17MW solar farms across Melbourne Water's Winneke Treatment Plant and Eastern Treatment Plant.

Also Victoria's megawatts accredited in 2021 is higher than that of 2020 in spite of a deterioration in payback levels due to an upward adjustment to incorporate the 12.4MW solar system being installed at Melbourne Airport.

NSW's numbers are also adjusted upwards across 2021 to 2024 to take into account a boost in installation levels as a result of the NSW Government's initiative to install 18MW of solar across government sites by the end of 2021 and 40MW by 2024.

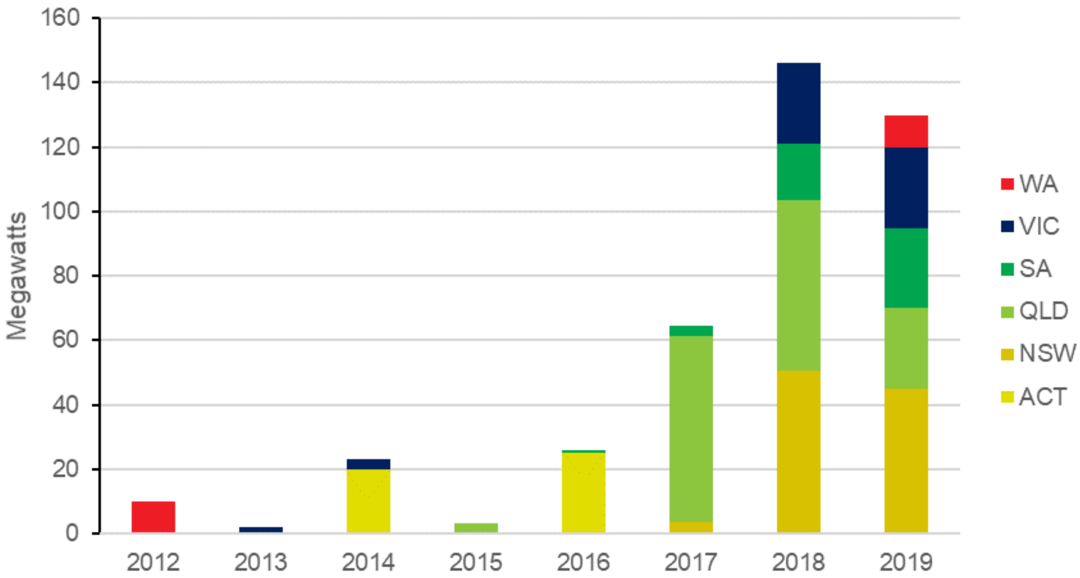
Lastly WA's 2020 relatively low installation levels are assumed to be an anomaly with 2021 recovering to levels more in line with payback relative to 2019 installation levels.

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. Figure 5-2 details annual capacity installations for power stations below 30MW back to 2012.

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



So far this segment has been a relatively minor portion of overall solar farm power station solar capacity additions (but is a significant part of the mid-scale solar market). Power stations smaller than 5MW have been particularly uncommon and most have been developed by a single company – Yates Electrical Services. However, due to the increasing difficulty and cost involved in obtaining grid connection for solar power plants 30MW in scale or greater, several developers are switching their attention towards smaller-scale plant, particularly those 5MW or smaller in size which are not subject to a range of system management and grid connection obligations.

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 wholesale market prices reflate. Therefore, one should logically expect a drop away in installation levels from past levels. However, there are three factors that suggest installations will continue:

- a number of developers and their investors lack a full appreciation of the commercial/market dynamics in Australian markets and/or are motivated by broader, longer term strategic drivers such as demonstrating their company's capability as a supplier of solar products or services;
- They are willing to accept very modest returns in the short-term on the expectation that either: a major coal fired power station will close; or new emission reduction policies will be introduced at either a State or Federal Government level that will significantly lift revenue;
- There are corporate electricity customers that are willing to sign long-term offtake agreements for these projects at prices noticeably above wholesale market rates in order to provide a tangible demonstration of their contribution towards carbon emission reductions.

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, 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)

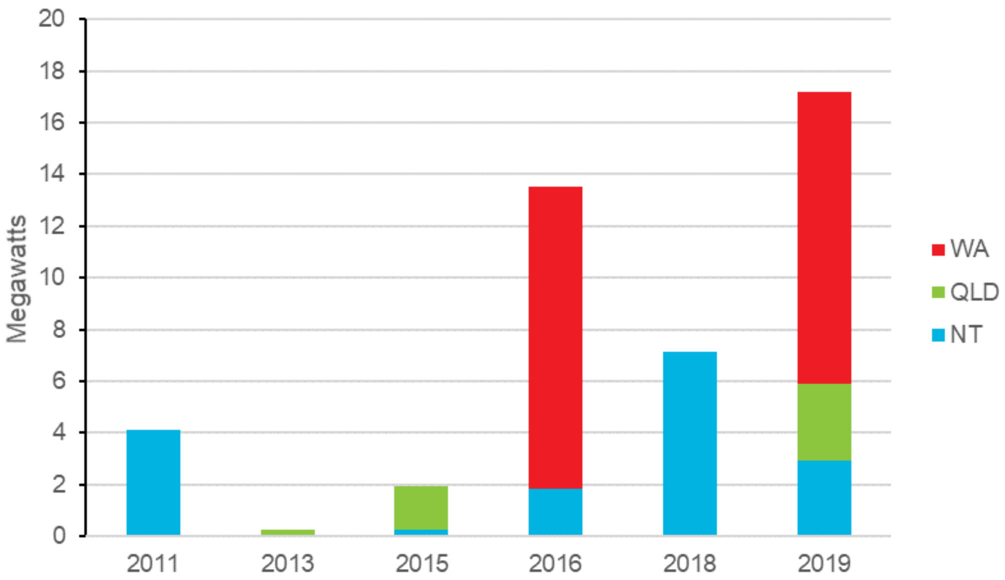
State/Territory	2020	2021	2022	2023	2024	2025
ACT&NSW	75	97	10	10	20	20
NT	45	0	0	0	0	0
QLD	0	15	0	0	0	0
SA	56	25	0	0	10	10
TAS	0	0	0	0	0	0
VIC	16	47	10	10	10	10
WA	32	30	0	0	0	0
TOTAL	**223**	**214**	**20**	**20**	**40**	**40**

The capacity levels in 2021 as well as 2020 (beyond those already accredited) are largely a function of projects that have already been committed or have long term offtake contracts in place and a working towards financial close. We then expect capacity to drop to low levels of 20MW per annum as a result of the collapse in daytime wholesale market prices. A small number of projects are still expected to proceed in NSW and Victoria due to higher daytime wholesale prices in these two states and also because these states tend to host a greater number of the types of businesses that would be willing to enter into a long-term offtake agreement for altruistic/public relations reasons (for example large corporates with household consumer-facing brands). By 2024 and 2025 we would expect power station numbers will pick up further due to the closure of Liddell Power Station and an expected recovery in the gas price acting to reflate wholesale prices by this time.

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. 41.2MW has been accredited since 2011 (see Figure 5-3) much of that accredited prior to 2019 was heavily subsidised via ARENA funding.

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



However, some recently announced projects for powering remote mine sites without grant funding suggest solar has reached a critical inflection point where its economics and demonstrated technical performance suggest installations could rise substantially without the need for ARENA funding. These include the Cannington, Granny Smith, Nova Nickel, and Agnew mine sites (ARENA funding was provided to support the wind but not the solar component of this project). Further reinforcing the viability of solar for remote power is that in these sites solar has been deemed attractive for displacing gas, which is noticeably cheaper than diesel. Public statements from Energy Developments Limited – one of Australia's largest operators of remote power systems – indicate that solar is economically viable now for displacement of gas up to 10% penetration and within 5 years they expect 50% displacement to be viable. Western Australia's remote power utility – Horizon Power – has also indicated publicly that they see solar as now being economically viable across many of their sites.

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.

Due to the significant drop in the oil price as a result of the COVID 19 induced downturn in oil demand we have scaled-back our projections of installations in the remote/off-grid market relative to last year's estimates prepared for the Clean Energy Regulator. The decline in the oil price has led to drops in the price of both diesel and gas which solar competes against in the remote/off-grid market. Table 5-3 details our estimates of megawatts by accreditation year. These are partially informed by announced system roll-outs by Horizon Power in Esperance and the Kimberley and another system upgrade at Umuwa in SA. Outside of these known initiatives our estimates of future capacity are highly speculative and uncertain given this sector has only just recently reached an economic viability threshold and has now been undermined by large falls in the oil price. 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 (putting aside the 3MW system to be installed in Umuwa in outback South Australia).

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

2020	2021	2022	2023	2024	2025
9	5	14	13	15	20

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 not register to create LGCs from 2022 onwards and instead opt to register to create ACCUs in NSW, QLD, SA and TAS. New Victorian systems would also be better off from 2022 onwards registering to create VEECs instead of LGCs. New systems in WA and NT would be better off registering to create ACCUs instead of LGCs from 2023 onwards.

Table 6-1 Expected annual ongoing LGC creation by year of plants' accreditation

State/Territory	2020	2021	2022	2023	2024	2025
ACT&NSW	67,551	86,393	ACCUs	ACCUs	ACCUs	ACCUs
NT	22,536	1,054	1,054	ACCUs	ACCUs	ACCUs
QLD	43,664	35,644	ACCUs	ACCUs	ACCUs	ACCUs
SA	25,419	255,622	ACCUs	ACCUs	ACCUs	ACCUs
TAS	524	756	ACCUs	ACCUs	ACCUs	ACCUs
VIC	54,642	62,273	VEECs	VEECs	VEECs	VEECs
WA	10,525	22,869	22,869	ACCUs	ACCUs	ACCUs
TOTAL	**224,862**	**464,612**	**23,924**	**0**	**0**	**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 Expected annual ongoing LGC creation by year of plants' accreditation

State/Territory	2020	2021	2022	2023	2024	2025
ACT&NSW	176,468	229,424	23,652	23,652	47,304	47,304
NT	114,318	0	0	0	0	0
QLD	0	38,106	0	0	0	0
SA	131,284	59,012	0	0	23,652	23,652
TAS	0	0	0	0	0	0
VIC	35,952	107,730	22,776	22,776	22,776	22,776
WA	78,490	73,584	0	0	0	0
TOTAL	**536,511**	**507,857**	**46,428**	**46,428**	**93,732**	**93,732**

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 ineligible to create ACCUs based on the existing available methodologies and so new systems continue to register to create LGCs

Table 6-3 Expected annual ongoing LGC creation by year of plants' accreditation

2020	2021	2022	2023	2024	2025
14,664	8,029	22,481	20,876	24,087	32,116

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.

7. Appendix A – Projected mid-scale capacity by system size bands

The table below apportions projected megawatts of capacity across system size bands. As explained earlier in this report projections of mid-scale solar uptake are highly uncertain at the aggregated level presented earlier in this report. Breaking this down further into how much capacity is likely to be installed within particular sizes of systems is subject to even greater levels of uncertainty.

Behind the meter systems – megawatts in each system size band

System capacity band	Region	2020	2021	2022	2023	2024	2025
100kW to 1MW	NSW & ACT	27.5	34.9	28.8	28.8	30.2	28.7
100kW to 1MW	NT	1.5	0.7	0.7	0.5	0.5	0.5
100kW to 1MW	QLD	17.7	14.4	16.2	17.1	18.9	23.4
100kW to 1MW	SA	4.1	27.3	6.9	7.3	7.9	9.0
100kW to 1MW	TAS	0.4	0.6	0.6	0.6	0.7	0.8
100kW to 1MW	VIC	29.7	15.7	52.5	29.0	29.0	32.8
100kW to 1MW	WA	3.6	8.2	8.2	7.0	6.8	6.8
>1MW to 5MW	NSW & ACT	20.0	25.8	21.3	21.3	22.3	21.2
>1MW to 5MW	NT	3.3	0.0	0.0	0.0	0.0	0.0
>1MW to 5MW	QLD	13.0	10.7	12.0	12.7	14.0	17.3
>1MW to 5MW	SA	12.5	38.3	5.1	5.4	5.9	6.6
>1MW to 5MW	TAS	0.0	0.0	0.0	0.0	0.0	0.0
>1MW to 5MW	VIC	12.0	11.6	4.5	21.4	21.4	24.2
>1MW to 5MW	WA	3.0	6.1	6.1	5.2	5.0	5.0
>5MW to 10MW	NSW & ACT	0.0	0.0	0.0	0.0	0.0	0.0
>5MW to 10MW	NT	9.2	0.0	0.0	0.0	0.0	0.0
>5MW to 10MW	QLD	0.0	0.0	0.0	0.0	0.0	0.0
>5MW to 10MW	SA	0.0	70.6	0.0	0.0	0.0	0.0
>5MW to 10MW	TAS	0.0	0.0	0.0	0.0	0.0	0.0
>5MW to 10MW	VIC	0.0	8.2	0.0	0.0	0.0	0.0
>5MW to 10MW	WA	0.0	0.0	0.0	0.0	0.0	0.0
10MW-30MW	NSW & ACT	0.0	0.0	0.0	0.0	0.0	0.0
10MW-30MW	NT	0.0	0.0	0.0	0.0	0.0	0.0
10MW-30MW	QLD	0.0	0.0	0.0	0.0	0.0	0.0
10MW-30MW	SA	0.0	30.9	0.0	0.0	0.0	0.0
10MW-30MW	TAS	0.0	0.0	0.0	0.0	0.0	0.0
10MW-30MW	VIC	0.0	12.0	34.2	0.0	0.0	0.0
10MW-30MW	WA	0.0	0.0	0.0	0.0	0.0	0.0

Off-grid/remote power systems – megawatts in each system size band

System capacity band	Region	2020	2021	2022	2023	2024	2025
100kW-1MW	National	0.0	0.0	0.0	1.0	1.0	1.0
>1MW to 5MW	National	2.1	5.2	14.0	7.0	9.0	14.0
>5MW to 10MW	National	7.0	0.0	0.0	5.0	5.0	5.0
>10MW to 30MW	National	0.0	0.0	0.0	0.0	0.0	0.0

Off-grid/remote power systems – megawatts in each system size band

System capacity band	Region	2020	2021	2022	2023	2024	2025
100kW to 1MW	ACT&NSW	0.0	0.0	0.0	0.0	0.0	0.0
100kW to 1MW	NT	0.0	0.0	0.0	0.0	0.0	0.0
100kW to 1MW	QLD	0.0	0.0	0.0	0.0	0.0	0.0
100kW to 1MW	SA	2.7	0.0	0.0	0.0	0.0	0.0
100kW to 1MW	TAS	0.0	0.0	0.0	0.0	0.0	0.0
100kW to 1MW	VIC	0.0	0.0	0.0	0.0	0.0	0.0
100kW to 1MW	WA	0.0	0.0	0.0	0.0	0.0	0.0
>1MW to 5MW	ACT&NSW	21.6	20.0	10.0	10.0	20.0	20.0
>1MW to 5MW	NT	0.0	0.0	0.0	0.0	0.0	0.0
>1MW to 5MW	QLD	0.0	0.0	0.0	0.0	0.0	0.0
>1MW to 5MW	SA	52.8	25.0	0.0	0.0	10.0	10.0
>1MW to 5MW	TAS	0.0	0.0	0.0	0.0	0.0	0.0
>1MW to 5MW	VIC	15.8	20.0	10.0	10.0	10.0	10.0
>1MW to 5MW	WA	2.0	0.0	0.0	0.0	0.0	0.0
5MW to 10MW	ACT&NSW	0.0	0.0	0.0	0.0	0.0	0.0
5MW to 10MW	NT	20.0	0.0	0.0	0.0	0.0	0.0
5MW to 10MW	QLD	0.0	0.0	0.0	0.0	0.0	0.0
5MW to 10MW	SA	0.0	0.0	0.0	0.0	0.0	0.0
5MW to 10MW	TAS	0.0	0.0	0.0	0.0	0.0	0.0
5MW to 10MW	VIC	0.0	0.0	0.0	0.0	0.0	0.0
5MW to 10MW	WA	0.0	0.0	0.0	0.0	0.0	0.0
>10MW to 30MW	ACT&NSW	53.0	77.0	0.0	0.0	0.0	0.0
>10MW to 30MW	NT	25.0	0.0	0.0	0.0	0.0	0.0
>10MW to 30MW	QLD	0.0	15.0	0.0	0.0	0.0	0.0
>10MW to 30MW	SA	0.0	0.0	0.0	0.0	0.0	0.0
>10MW to 30MW	TAS	0.0	0.0	0.0	0.0	0.0	0.0
>10MW to 30MW	VIC	0.0	27.3	0.0	0.0	0.0	0.0
>10MW to 30MW	WA	30.0	30.0	0.0	0.0	0.0	0.0