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Life Is On | Schneider Electric

Realizing the Potential of Customer-Sited Solar

Policy and Economics for a Decentralized Energy Future

September 15, 2021

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Foreword

With the majority of global greenhouse gas emissions now covered by some form of government net-zero target, there is unprecedented urgency to accelerate the global energy transition. Central to these efforts is the power system, which is simultaneously the sector most responsible for carbon emissions, and the one most likely to decarbonize first.

But as we now know, the decarbonized power system of the future will look fundamentally different from the power systems of the past. Thanks to the rapidly falling costs of solar technology, for the first time consumers in various parts of the world can now economically generate some of their own power. This has mobilized new sources of capital to invest in the customer side of the energy transition, while delivering economic benefits to customers and grid operators, and creating local employment opportunities. It has also unlocked energy access for millions.

As energy storage costs fall, a second transition is beginning, where customer-sited solar combined with storage can begin to provide greater benefits to the power system, in terms of energy balancing, grid services and increased resilience. And, as net-zero goals drive greater electricity demand in transport and buildings, customer-sited energy resources could play an even more important role in optimizing local energy supply and demand.

Although several countries and markets have raced ahead (including some of those profiled in this report), these small-scale, decentralized energy resources remain largely untapped. To unlock them will require thoughtful application of a range of policy and regulatory levers, to stimulate efficient, sustainable investment in these new technologies.

This report provides new analysis on the impact of different policy levers on the attractiveness and uptake of customer-sited solar and storage, focusing on five currently active markets as case studies. It puts forward a framework for how to address customer-sited solar and storage from a policy and regulatory point of view, to enable sustainable growth of these technologies within the broader goal of rapidly and efficiently decarbonizing the power sector. While the case studies are drawn from leading, developed markets, we believe that the learnings can be applied to a broad range of market contexts around the world.

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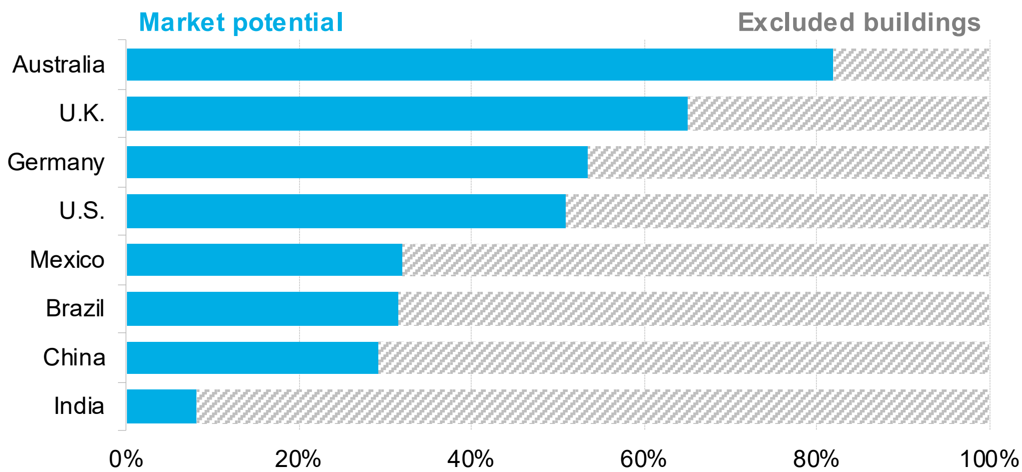
Executive Summary

Customer-sited solar is a significant opportunity, which will materialize in the coming decades and bring change to energy markets and power network operations. There has been significant debate about how best to structure incentives and regulations around customer-sited solar – and more recently solar-plus-storage – and the considerations are complex. Policy makers must aim to stimulate development that realizes the benefits of these technologies, while avoiding the potential adverse effects of large-scale uncoordinated development. There have been limited studies at a global level to examine the impact of different policies on the economics, and therefore the uptake, of customer-sited solar (at first without, and later with storage). This report seeks to address this gap, and presents new economic analysis based on use cases in key solar markets, California, New Jersey, Australia, Spain and France.

- A huge potential exists for more distributed generation on buildings and facility rooftops. Studies vary in assumptions and scope, but all confirm the potential is considerable. More than half of rooftops in the U.S. or Germany could host solar, and this ratio goes up to two-thirds in the U.K. and up to 80% in Australia.

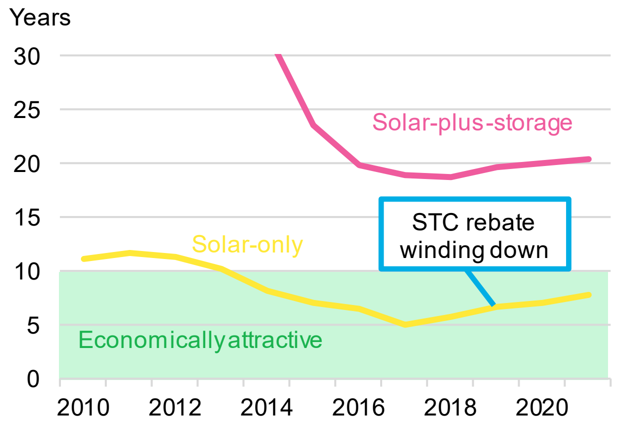
Figure 1: Residential market potential in 2050, selected countries



Source: BloombergNEF

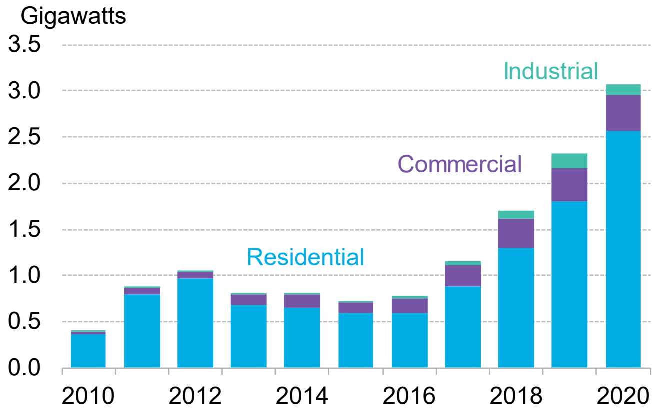
- This identified potential is likely to materialize sooner and faster than often anticipated. On the one hand, sustainability and resiliency issues drive a case for customer-led adoption. On the other hand (and perhaps most importantly) the rapid cost convergence of small-scale solar with retail electricity over time, driven by continuous improvement of technology and value chains, will improve the economics. While this convergence has already happened and is already driving growth in specific regions (in general those with higher retail electricity prices, such as for residential customers in Australia, see Figure 2 and Figure 3), our analysis predicts it will be a common pattern globally within the next decade.

Figure 2: Paybacks of Australia residential solar and storage



Source: BloombergNEF. Note: This is a sample average for Australia. System sizes, STC solar rebates, variable rates and export rates vary by state and over time. As reference, average variable rate in 2020: A$0.24/kWh. Average load also varies by state.

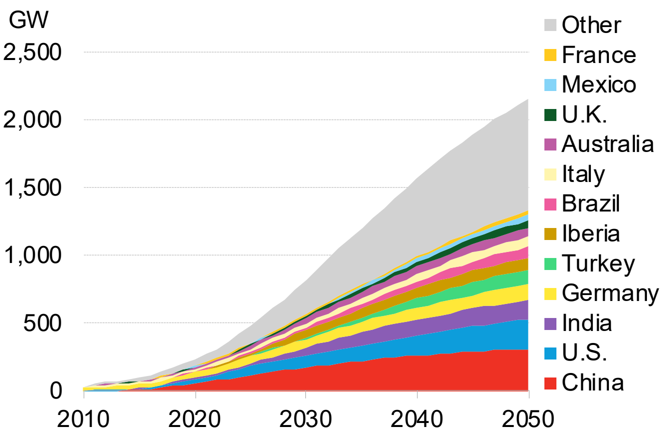
Figure 3: Annual Australia behind-the-meter solar capacity additions



Source: BloombergNEF

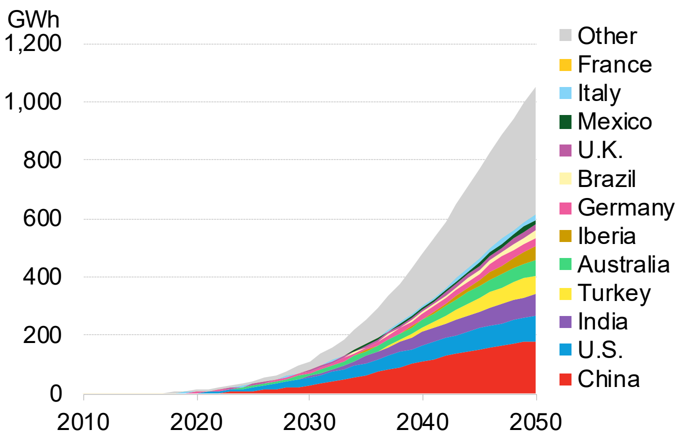
- Looking longer-term, BloombergNEF's modelling projects a total installed base of 2.2TW customer-sited solar by 2050. In this scenario, by 2050, 167 million households and 23 million businesses 'go solar' globally, representing an eight-fold increase from the 0.27TW installed by end-2020 (Figure 4). Provided roadblocks to development are removed, as described in this report, the long-term projection could in fact be larger.

Figure 4: Global cumulative customer-sited solar capacity by region, to 2050



Source: BloombergNEF

Figure 5: Global cumulative customer-sited storage capacity, by region, to 2050



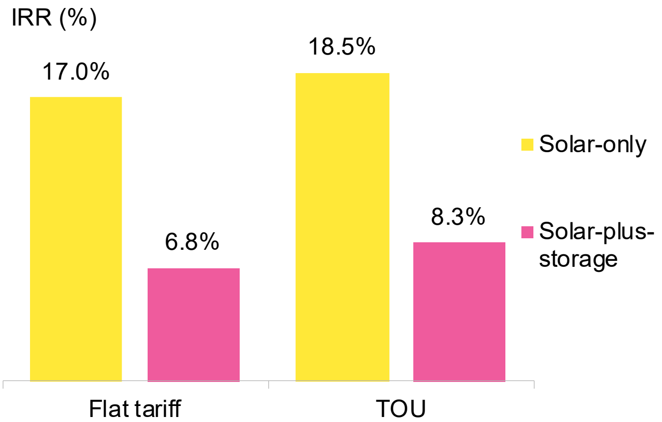
Source: BloombergNEF

- For uptake of this scale – and perhaps greater – to materialize, there are four key areas that policy makers will need to pay attention to:
  - Policies that help kick off adoption, before the natural economic rationale drives accelerated adoption
  - Policies focusing on solar during new building construction
  - Policies that encourage adoption of storage and flexibility on top of solar when the rate of penetration exceeds a certain threshold
  - Policies that help remove other barriers to adoption (occupancy, financial, regulatory)
- **Kicking off adoption:** for the market to get started, customers (households and businesses) must see a positive investment case for solar. In markets where customer-sited solar is not yet a positive business case on its own, policy makers can get the ball rolling by introducing incentives. These must be carefully calibrated to stimulate development without leading to an unsustainable boom. While the economics varies across the country, in France for example, with feed-in tariffs under the 'self-consumption' scheme, households on a time-of-use (TOU) rate can achieve a payback of 5 years on solar projects (IRRs of 18.5%, Figure 6), while businesses on a TOU rate can achieve an IRR of 10.4%, or a 9-year payback (Figure 7).

Paybacks vs. IRRs

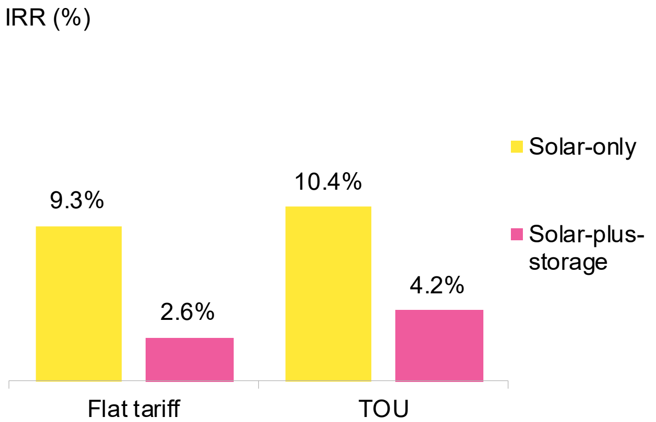
In this report, we refer to both paybacks and internal rates of return (IRRs) but chart only IRRs for comparative purposes. Paybacks (years it takes to recoup investment) are inversely related to IRRs (the percentage return the asset is expected to provide over the lifetime of the system).

Figure 6: Economics for residential solar and solar-plus-storage installed in France, 2021



Source: BloombergNEF. Note: 5.2kW PV and 7.2kWh battery systems, 5,354kWh/year household. Flat retail rate: EUR 0.16/kWh ($0.19/kWh). TOU: Variable peak: 6AM-10PM, EUR 0.18/kWh ($0.21/kWh), Off-peak: 10PM-6AM EUR 0.13/kWh ($0.15/kWh). Assumes compensation under self-consumption scheme. Additional assumptions in Appendix A.

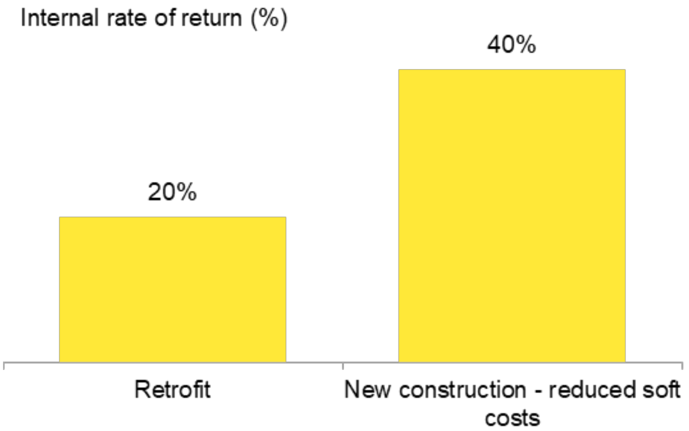
Figure 7: Economics for commercial solar and solar-plus-storage installed in France, 2021



Source: BloombergNEF. Note: 20kW PV and 10kW/20kWh battery systems, office load consuming 40,000kWh/year. Flat retail rate: EUR 0.10/kWh ($0.12/kWh). TOU: Variable peak: 6AM-10PM EUR 0.11/kWh ($0.13/kWh), Off-peak: 10PM-6AM EUR 0.08/kWh ($0.09/kWh). Assumes compensation under self-consumption scheme. Additional assumptions in Appendix A.

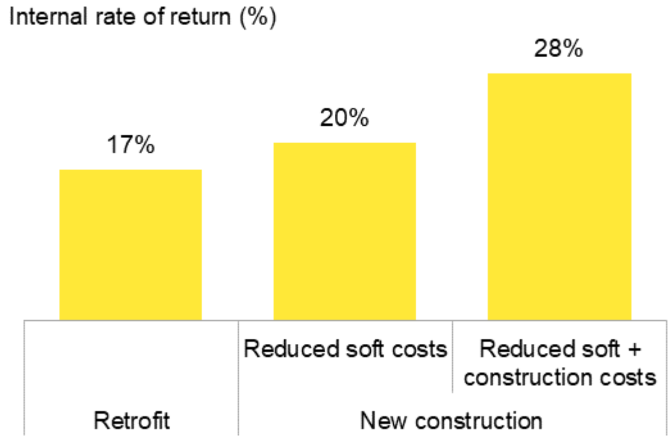
- **Unlocking solar for new-build homes and businesses:** Installing solar when buildings are constructed is cheaper than retrofitting to existing buildings and delivers a clear value proposition. Solar companies can cut down on soft costs, including sales, marketing and permitting, by partnering with home builders. They can also save on solar construction costs, such as labor and scaffolding.
- In California, we estimate that returns on new-build residential solar are around 20 percentage points higher than for retrofits (Figure 8). If solar companies can reduce their soft costs by 80% and install residential solar for $1.6/W, then returns for the solar investment would be 40%, equivalent to a 3-year payback, down from 6 years.
- In markets outside the U.S., soft costs make up a smaller part of PV capex and the returns for solar on new-build homes relies heavily on construction cost savings. In France, for example, 80% lower soft costs would decrease residential solar returns to a 5-year payback, down from 6 years (or improve IRRs to 20%, up from 17%, Figure 9). If solar installers can also save $0.25/W in labor and scaffolding costs, then new construction paybacks would decline further, to 4 years, as returns would increase even more, to 28%. This is a full 10 percentage points higher return than the retrofit case.
- Despite the clear value proposition, builders are not commonly adding solar to new buildings. This is because selling solar systems is not their core business and builders are also often mainly defaulting to incumbent building design and engineering choices when making construction decisions, while ensuring they comply with most recent building codes. Hence, government mandates can be an effective way to ensure that these investments are made.

Figure 8: Returns for residential solar in California – retrofit versus new construction



Source: BloombergNEF. Assumes 8kW PV system, 12,000kWh/year home. Federal ITC applied. Export rate = 100% retail rate. TOU rate: Peak: 4-9PM $0.41/kWh, Off-peak: $0.17/kWh. Retrofit capex = $2.8/W, New construction capex = $1.6/W. Additional assumptions in Appendix A.

Figure 9: Returns for residential solar in France – retrofit versus new construction

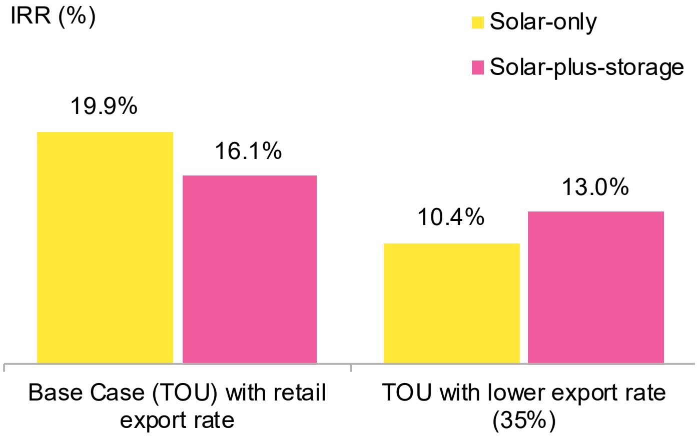


Source: BloombergNEF. Note: 5.2kW PV system for a home consuming 5,343kWh/year on a EUR 0.16/kWh ($0.19/kWh) variable rate. Subsidized compensation for exports and 'self-consumption premium' under self-consumption scheme, Retrofit capex = $1.4/W, Reduced soft costs capex = $1.0/W, Reduced construction costs = $1.0/W. More assumptions in Appendix A.

- **Introducing storage as solar penetration rises:** As the charts above for France show, the business case for solar-plus-storage is initially worse than that for solar alone. This is appropriate: while solar penetrations are low, the addition of solar creates the most value as it generates at peak times and helps offset the customer's energy consumption bill at these times. The incremental cost of adding storage outweighs its benefits.
- Over time however, and as solar penetrations rise, the value of storage rises as it can be used to shift energy production from peak solar hours (which are increasingly devalued due to higher solar production) to evening hours (which are now of higher value as dispatchable generators ramp up to meet the evening peak). The value of solar alone falls, as power markets become saturated with midday generation, and local grid issues such as voltage disturbances rise.
- Energy storage, as well as flexible loads such as electric heating and electric vehicle chargers, can help balance the power system and prevent disturbances on the local distribution grid at higher solar penetrations. At this stage, the challenge becomes to create the right incentives for greater flexibility, while reducing incentives for solar alone.

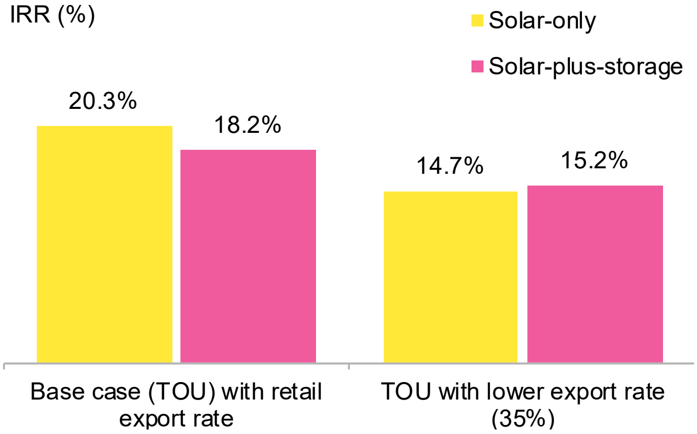
  There are several levers that can help. Simply lowering export rates (the tariff paid to solar customers for energy they export to the grid), for example, can tip the balance towards adding energy storage. In California, current incentives favor solar alone (base case TOU in Figures 6 and 7 below). We modeled a scenario where export rates (the tariff paid to solar customers for energy they export to the grid) are cut to just 35% of the applicable retail rate at the time of export (TOU with lower export rate in Figures 6 and 7 below). In this scenario, the economics of both solar-alone and solar-plus-storage are worsened. But the economic rationale for customers now skews towards adding storage to each new customer-sited solar installation, as internal rates of return for solar-plus-storage get better than for solar-only (13% vs 10% for residential, or 8-year payback vs 10 years, 15.2% vs 14.7% for commercial, or 6-year payback). With a battery, customers can use more of the solar electricity generated so they rely less on export payments.

Figure 10: Returns for California residential solar-only and solar-plus-storage under different export payment rates



Source: BloombergNEF. Note: 8kW PV and 5kW/14kWh battery systems, 12,000kWh/year home. Federal tax credits, rebates for storage assumed. TOU rate: Peak: 4-9PM $0.41/kWh, Off-peak: $0.17/kWh. Base-case export rate = 100% retail rate. Additional assumptions in Appendix A.

Figure 11: Returns for California commercial solar-only and solar-plus-storage under different export payment rates



Source: BloombergNEF. Note: 100kW PV and 50kW/100kWh battery system, 166,000kWh/year office load. Federal tax credits, rebates for storage assumed. TOU rate: Peak: 4-9PM $0.36/kWh, Off-peak: $0.08/kWh, demand charge: $22.77/kW. Additional assumptions in Appendix A.

- There are a range of other policy levers that can be applied to improve the business case for adding energy storage. In addition to lower export rates, as shown above, these include:
  - **Time-of-use retail electricity rates**, which value evening electricity higher than daytime electricity: these increase the incentive to add energy storage so that solar power can be stored for use in the evening.
  - **Payments for grid services**: programs that enroll customer batteries into demand-side management or virtual power plant programs, paying customers for delivery of ancillary services and demand reductions.
  - **Demand charges (primarily for business customers)**: these introduce a fee that business electricity users must pay, proportional to its highest kW power draw during a given billing period. These create an incentive to use energy storage to smooth out energy demand in general, with or without solar.
- **Reducing other barriers:** In addition to the incentives and issues above, policy makers must also pay attention to adoption barriers relating to occupancy, financing and misalignment of utility incentives. In numerous jurisdictions, split incentives mean that building owners either cannot or will not invest in solar. They may also lack capital to invest in solar, and utilities may resist the adoption of solar due to misaligned incentives. Policy makers can begin to address these issues through a range of initiatives and programs, such as community solar, third-party financing and re-alignment of utility incentives and revenue structures, to lower barriers to customer-sited solar adoption.

Section 1.

Customer–sited solar: huge potential, significant benefits

Section 1. Customer-sited solar: huge potential, significant benefits

Distributed generation, and customer-sited solar in particular, have grown quickly in recent years and could play a major role in the low-carbon energy transition. The market potential is huge and remains largely untapped, despite rapid progress in a few leading markets such as Australia, Hawaii and California. Customer-sited solar delivers benefits to both the customer and the wider power system, and when paired with storage can deliver even more value. It also allows for a democratization of the energy system with the active role of citizens and businesses, reducing energy costs and preserving biodiversity with the introduction of renewables.

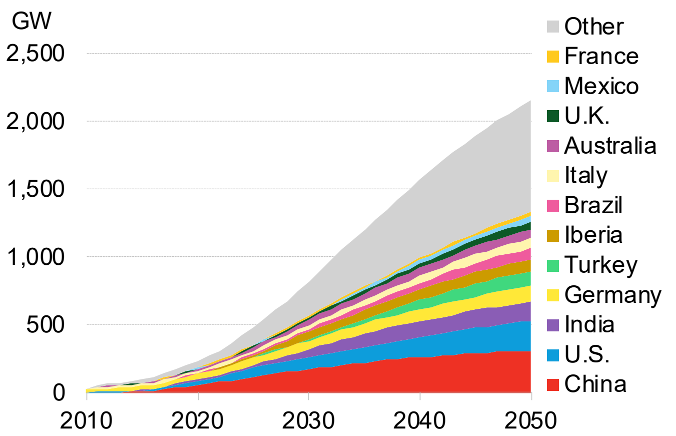
1.1. Customer-sited solar can play a big role in power systems

Current projections may underestimate total solar potential

BloombergNEF's modelling projects a total installed base of 2.2TW customer-sited solar by 2050. In this scenario, by 2050, 167 million households and 23 million businesses 'go solar' globally, representing an eight-fold increase from the 0.27TW installed by end-2020. Uptake is spread out across the world, with China, the U.S. and India representing the largest markets by 2050 (Figure 12). This projection represents a significant change in the way power systems and networks are currently designed and planned for, with a major shift towards distributed energy generation.

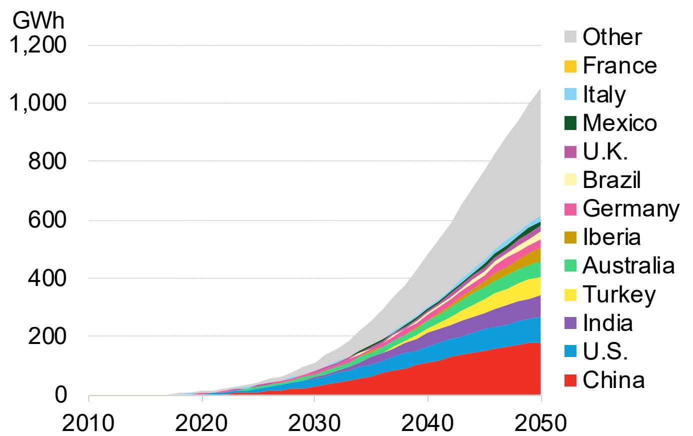
Customer-sited storage, when paired with these solar systems, offers users the ability to consume more of their solar generation, provides resilience in the form of back-up during a blackout, and the potential to capture new revenue streams by providing services to the grid. To date, relatively few solar users have added batteries to their solar systems, because of the additional cost. BloombergNEF projects that China, California and Australia will be the earliest markets to adopt storage at scale and will account for most installations over the next decade. Customer-sited solar is paired with 450GW/1,047GWh of storage by 2050, with the vast majority (89%) of this installed after 2030 (Figure 13), as battery costs fall.

Figure 12: Global cumulative customer-sited solar capacity by region, to 2050



Source: BloombergNEF

Figure 13: Global cumulative customer-sited storage capacity, by region, to 2050



Source: BloombergNEF

The total potential for both customer-sited solar and storage could be even higher than this scenario suggests. Underpinning our base-case scenario is the assumption that customers will install solar in order to offset their electricity bill, green their power supply and achieve some independence from the grid. Additionally, batteries are mainly deployed to enhance self-consumption (so that the user can consume more of its own solar generation, typically in the evening). Crucially, the scenario assumes no continuing policy support for customer-sited solar and storage in the long term, and limited ability to be paid for grid services.

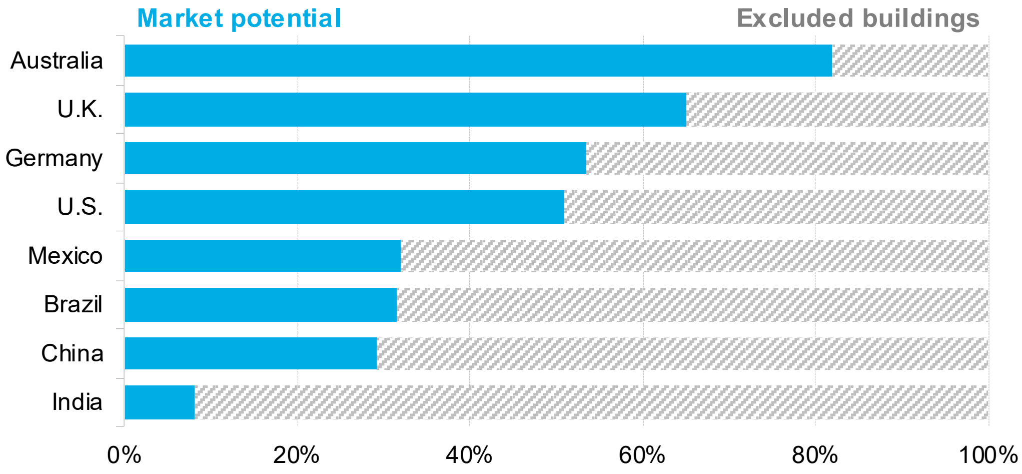
In practice, with some policy support, customer-sited solar is already economically attractive in many regions around the world and there has already been dramatic uptake worldwide. Storage systems are already being deployed too, where the right economic signals exist. Solar cost reductions will offset policy phase-out and allow it to grow steadily over the next 30 years, and a similar dynamic will exist for energy storage technologies,

Physical and economic factors govern the overall potential

To understand just how far customer-sited solar could go, it is important to understand the physical and economic factors that limit how much can be installed in any given market. High-density living, poor physical suitability of buildings, poor affordability and competing uses for rooftops can all limit market potential. On the other hand, technology improvements and cost declines can increase market potential over time, as can population increases and building stock churn. But urbanization will reduce the percentage of customers that have their own roof space. Conversely, in regions where households and businesses move away from cities, as has been observed during the Covid-19 pandemic, the potential for customer-sited solar increases.

We find that more than 80% of residential buildings in Australia can host rooftop solar, as can roughly two-thirds of U.K. homes. For Germany and the U.S. the market potential is about half of residential buildings.

Figure 14: Residential market potential in 2050, selected countries



Source: BloombergNEF

Relative to population, market potential is lower in India, China and Brazil than in other regions. In India, for example, many customer-sited owners have limited capital availability, and there are competing options for investment decisions and roof uses, such as water tanks, air drying and recreation. Not all roofs can bear the load of solar systems. We estimate that only a third of current rural dwellings are suitable for solar. Over time, urbanization will increase the share of multi-story apartments, further limiting the ability for households to install their own solar.

Although BloombergNEF analysis discounts customer sites for suitability, we recognize that other studies often reveal higher levels of potential, and can even show orders of magnitude higher than what our current analysis suggests. In the U.S., for example, by 2050 BloombergNEF's projections suggest customer-sited solar would make up 6% of total generation. Google's Project Sunroof suggests there is enough suitable roof space for customer-sited PV to supply 39% of the country's overall energy needs, and therefore an even higher share of electricity needs alone.[1]

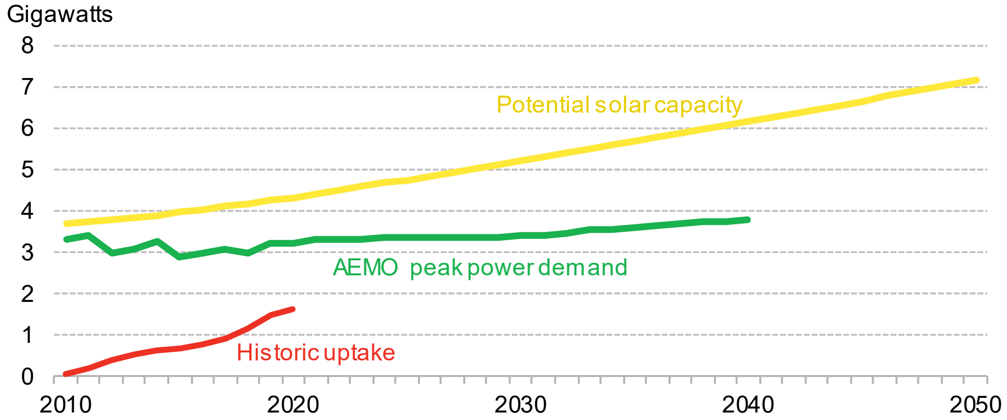
There is also additional land on customer premises that can be used for solar. In Europe, a study found customer-sited systems could supply up to 24.4% of the EU's 2016 electricity consumption.[2] Another study found there is enough suitable space in Australia for rooftop solar to produce 245TWh a year, more than the country's current electricity demand.[3]

In short, the potential for customer-sited solar is large, and still largely untapped.

Solar can add more value when paired with storage

In reality, the electricity system can only absorb so much solar power at once. Figure 15 gives some perspective on this in Australia, where total solar capacity potential would actually exceed peak power demand, if materialized. Achieving such a high level of customer-sited solar would require deployment of local flexibility at the distribution network level (both from behind-the-meter and front-of-meter assets), digital grid technologies and adequate market regulations – as well as more energy storage. South Australia, for example, had the lowest incidence of minimum demand on October 11, 2020 at 12:30PM. Solar in aggregate (grid solar included) was 100% of underlying demand for the first time on record, while distributed solar contributed to 77% of that.

Figure 15: South Australia peak power demand versus potential and actual customer-sited solar capacity



Source: BloombergNEF, Australian Energy Market Operator (AEMO). Note: AEMO's estimate for peak power demand generally occurs during the evening, outside of peak solar production hours.

1 Google, *Reaching our solar potential, one customer-sited at a time*, December 2016

2 Bódis et al., *A high-resolution geospatial assessment of the customer-sited solar photovoltaic potential in the European Union*, October 2019.

3 Roberts, M., Nagrath, K. Briggs, C., Copper, J., Bruce, A., and Mckibben, J (2019) How Much Rooftop Solar Can be Installed in Australia? Report for the Clean Energy Finance Corporation and the Property Council of Australia. Sydney.

In addition, if left unmanaged, there is a limit to how much customer-sited solar can connect to the grid before quality of supply is compromised. There are a range of technical challenges posed by solar that affect the system – such as balancing, managing frequency and inverter tripping – and the distribution grid – primarily voltage disturbances and thermal conditions. According to South Australia Power Networks (SAPN), once 25%-30% of households in an area have customer-sited PV, customers will experience voltage levels outside the regulated range.[4] Batteries will play a key role in integrating customer-sited PV, providing needed flexibility on the distribution network. It will allow customers to consume more solar generation on-site, rather than exporting to the grid.

Battery storage will be a key solution for these challenges, but it is not the only way for customers to use more of their solar generation. Shiftable loads can also help absorb more solar during the day, without the additional cost of adding a battery. Hot water tanks allow customers to heat water using solar hours and store for use later in the day. As electric vehicle penetration increases, vehicle batteries could store solar power generated during the day. We expect that at least 63% of the 1.4 billion passenger vehicle fleet will be electric by 2050, providing significant potential for customer-sited flexibility.[5]

1.2. Price signals matter

There are many challenges to realizing the huge potential of customer-sited solar. In this report, we focus on two main ideas.

The first is that policy and regulation needs to be right: designing policy mechanisms to help accelerate the uptake of customer-sited solar requires careful consideration, and that consideration is different in early-stage markets compared to more mature markets. The good news is that cost reductions in the solar and storage value chains are already enhancing the competitiveness of customer-sited generation and storage.

The second idea is that deep decarbonization, and higher levels of solar penetration, require careful policy design to incentivize the uptake of flexible technologies such as energy storage. These two issues are introduced here and explored in depth in the next section.

Customer economics drive uptake

A customer's decision to 'go solar' can be thought of as an investment decision, where the capital expenditure is the cost of installing solar (with or without storage) and the return comes from energy bill savings and revenues from exports or other grid services. The economics vary a lot based on subsidies, export rates (the price paid to the customer for the solar energy it provides to the grid) and retail electricity rates (the price paid by the customer for power provided by its energy supplier). Because of their importance, these two terms, 'export rates' and 'retail rates', are used frequently throughout this report.

Experience from many markets shows that most customers will only make this jump if the returns are adequate (though there are always early adopters that buck this trend). The required internal rate of return (IRR) depends on the region, segment, customer and their financing options. Residential and commercial customers also differ. The appetite of a business to invest in a solar

4 SAPN's LV Management Business Case.

5 This is based on BloombergNEF's Economic Transition Scenario. For more on this analysis, see BloombergNEF's *Long-Term Vehicle Outlook 2021*, full report available to BloombergNEF subscribers at (web | terminal).

option depends on other potential investment opportunities (including other capital investments), whether they have cash or access to loans or other forms of investment, and their appetite to invest in general. As a rule of thumb, in markets such as Europe and the U.S., acceptable payback periods in the residential segment are 9 years or less, while in some emerging markets that could be much lower (1 to 3 years) due to more of the population having less disposable income to invest. In the commercial segment, IRRs that would be sufficient to encourage investment varies significantly and are tied to commercial interest rates, which vary by market. We'd consider a premium to commercial interest rates, which could range from 6-14% in the U.S. to 16-23% in India.[6]

Figure 16: Residential solar payback periods, 2021

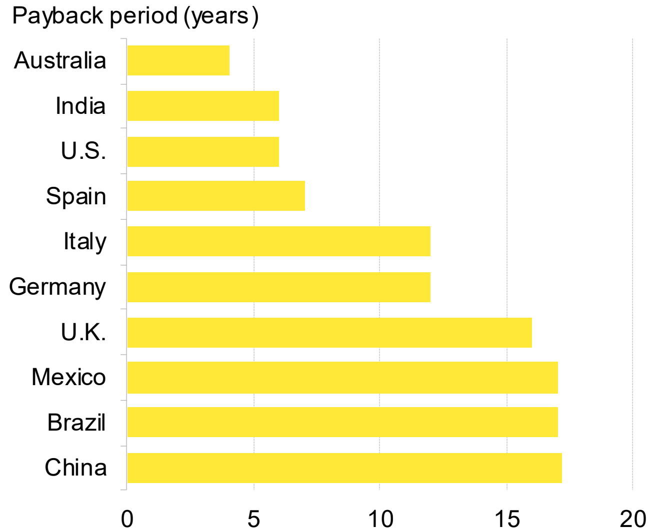
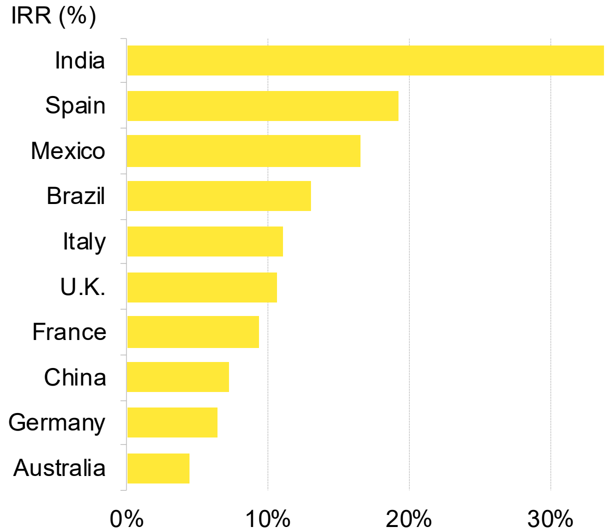


Figure 17: Commercial solar IRRs, 2021



Source: BloombergNEF. Note: For inputs and calculations see our Energy Consumption Optimization Model *(web | terminal). Assumes 25-year system life with battery replacement after 14 years. U.S. represents the average of 50 states plus District of Columbia, weighted by addressable market.*

In many regions, customer-sited solar is already an attractive investment, or is approaching economic competitiveness. But the design of retail tariffs, export rates and other policy factors is a key determinant of these economics. Much of the rest of this report focuses on how different policy and regulatory levers can be applied to change the IRR, and thus change the rate of customer adoption, while delivering positive benefits to the overall energy system. These levers include changes to retail electricity price structures, export rates and the ability to be paid for grid and system services.

Customer-sited solar paired with flexibility can deliver further system benefits

To be clear, the objective should not be to achieve maximum solar build at all costs, but rather to stimulate the market in an economically efficient way, and ultimately to phase in energy storage (or other forms of flexibility) at the right point in market development.

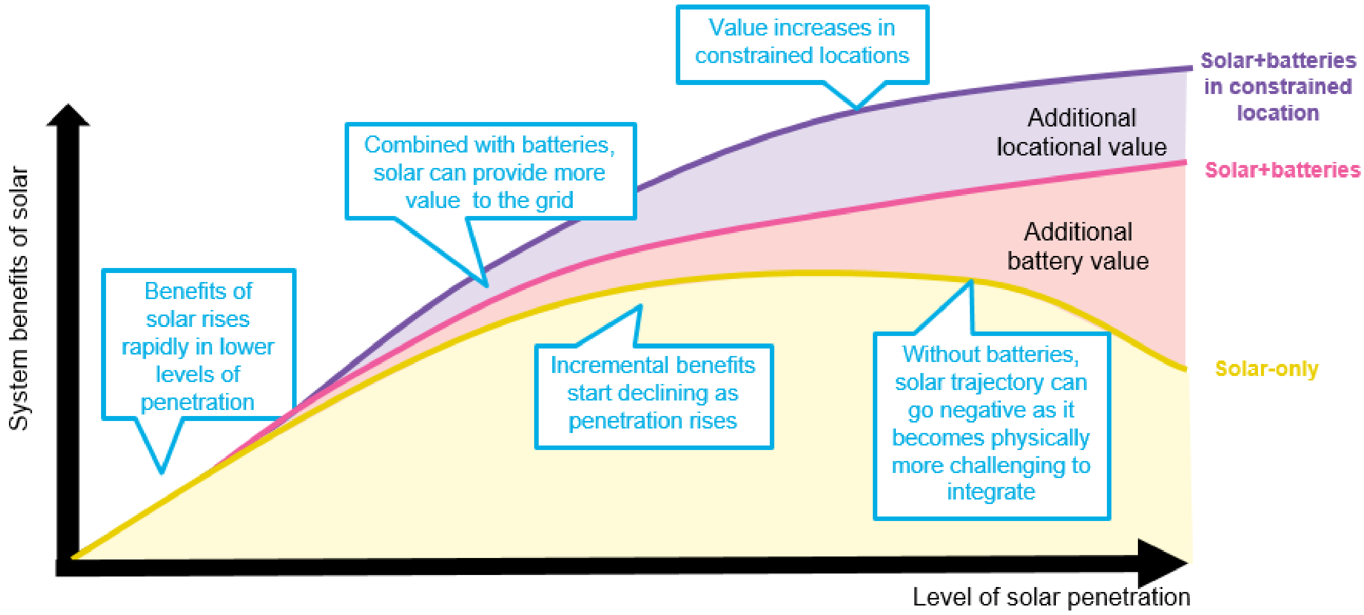
[6] Range includes unlevered and levered project assumptions, as financing decisions vary also by market and customer type. Note that individual business' appetite to invest in solar would vary also by its size and its business. The smaller the business, the more they may expect to see from an investment in a non-core part of their activities to think it's worthwhile to invest.

This is the case for a few reasons. First, as several markets have experienced in the past, over-incentivizing rooftop solar alone can create a boom-and-bust dynamic, while increasing costs either to taxpayers or to energy customers, depending on how the costs are allocated. This is now a well-understood dynamic and future boom-and-bust cycles are less likely thanks to lessons learned.

A more structural dynamic, and a key focus of this report, is what happens in the longer term when customer-sited solar reaches high penetrations. As solar penetrations grow in a region, there comes a point where aggregate solar production in the daytime approaches the total electricity demand of the region. Clearly, beyond this point, adding more solar ceases to add value to the overall electricity grid, as the energy is not needed at the time it is produced. (It should be noted, however, that further electrification of energy uses in transportation, buildings and industries may help raise this threshold.)

For this reason, policy and regulatory approaches (rate designs in particular) should be tuned to encourage adoption of solar paired with the ability to deliver its energy flexibly, after a certain level of penetration. This transition, managed carefully, can ensure that decentralized energy resources continue to add more value to the overall energy system, while also benefiting customers. A prime option is stationary batteries, which can provide that flexibility without the need to change customer behavior. This value may be even higher if the resources are located in geographical areas with limited grid connectivity. Figure 18 shows these ideas in an illustrative diagram.

Figure 18: How the system benefits of solar and batteries change with higher levels of penetration



Source: BloombergNEF. Note: this is merely illustrative. The actual levels of penetration and benefits will depend by market and grid infrastructure.

Besides batteries, other options can and will play a role in supporting further solar penetration, (see box below).

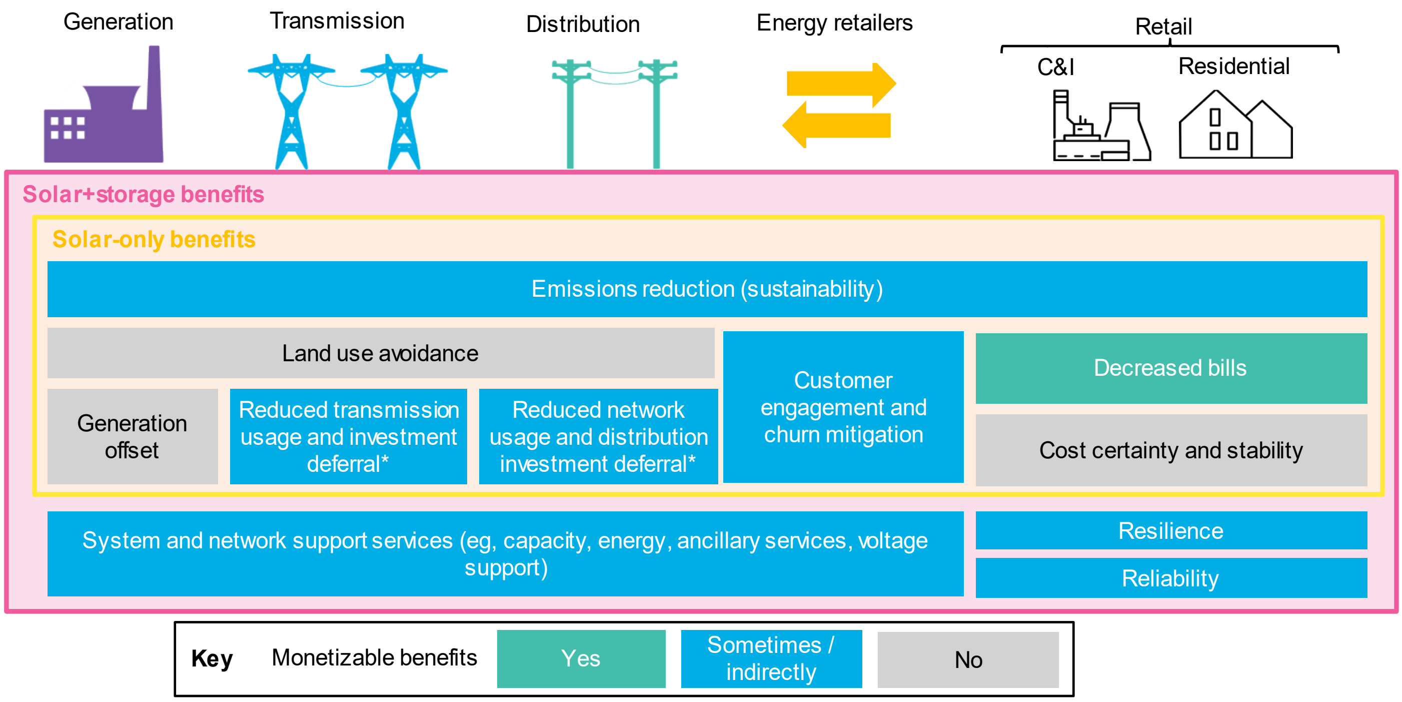
Demand-side flexibility beyond batteries

While the focus of this report and its analysis is on batteries, we are likely to see a plethora of forms of demand-side flexibility emerging that can support deeper levels of customer-sited solar penetrations. Flexing loads can be done in many ways including changing energy consumption behavior (running the washer or charging electric cars at certain times) or pre-programming water and space heating (and cooling) to align with solar hours. These may end up helping to increase on-site solar self-consumption and potentially improve economics of the solar system. In France, for example, there are an estimated 15 million electric water heaters that can represent up to 20GW of installed capacity and 25TWh of daily load.[7] Some of these can become sources of zero-marginal cost energy storage, compared to batteries, which require investment in additional hardware.

Note, however, that most of these are not bi-directional, so provide a different level of flexibility as they don't re-inject energy to the customer site or grid. Electric vehicles' bi-directional capabilities (also known as vehicle-to-grid or vehicle-to-home) are growing, but these are not yet common features.

Analyses (including our IRR analysis further above) generally focus on customer monetary benefits from installing a solar (and storage) system – rightly so as this is the primary driver for uptake. There are, however, a significant number of other benefits (as well as costs) that are not paid/charged when a solar and storage system is installed onto a customer site.

Figure 19: Benefits of customer-sited solar and storage



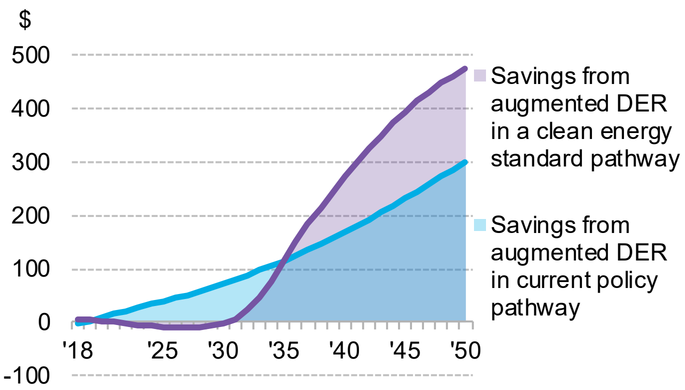
*Source: BloombergNEF. Note: *transmission and distribution investment deferral are location-specific, storage can often provide more benefits than solar. Size of boxes does not correlate with size of benefit. This figure does not illustrate costs of customer-sited solar and storage, for example grid exports can generate a cost that networks take on – some of these may be embedded in how the export rules and tariffs are designed.*

[7] EDF (2020) comments on studies for ecodesign and ecolabelling for water heaters and storage tanks.

Figure 19 shows a few of these from a customer and system perspective. From a customer perspective, reduced dependence on the utility, access to clean generation and reduced emissions and resilience benefits (with batteries) are benefits that are generally not monetized. On the utility and network side, on-site solar can reduce overall demand from the grid, offset generation and fuel consumption which can free up the network and reduce grid congestion. These can also help relieve land use for other activities.[8] Across the network there are overall benefits from reductions in emissions.

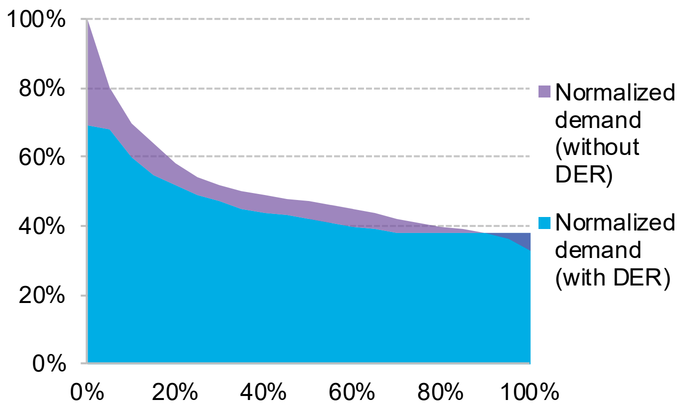
Some studies estimate significant savings if the benefits of distributed solar and storage were accounted for, or if capacity modelling accounted for the optimization of distribution- and transmission-connected resources.[9] One study for the U.S. shows that optimizing local solar and storage can result in between $300 and $480 billion cumulative savings for the U.S. (Figure 20). These savings are in large part generated by a more distributed load duration curve (Figure 21) that could be achieved by making better use of distributed energy.

Figure 20: Cumulative electricity spending savings from augmented DER modelling for the U.S.



Source: Vibrant Clean Energy. Note: the savings are relative to two distinct pathways, in both, the 'augmented DER' refers to modelling which includes distribution modelling.

Figure 21: DER altered load duration curve for example state



Source: Vibrant Clean Energy

Ultimately, policy and regulatory levers should be applied so that they encourage the right levels of solar and storage investment, delivering benefits both to the energy system as a whole and to the customer.

8 There are often competing interests for use of land for renewable deployment. In suburban areas there is usually competition on land use (real estate, local agriculture, local ground mounted solar), or even restrictions to use new land for energy projects, so using customer-sited systems for further renewable development is an important path forward. Decentralized on-site generation generally encounters less push-back than utility scale, as permitting and opposition from citizens on local "nuisance" are unlikely.

9 Vibrant Clean Energy, *"Why Local Solar Costs Less: A Road Map for the Lowest Cost Grid"*, 2020.

LBNL, *"Locational Value of Distributed Energy Resources"*, 2021

Section 2.

Getting the policy environment right

Section 2. Getting the policy environment right

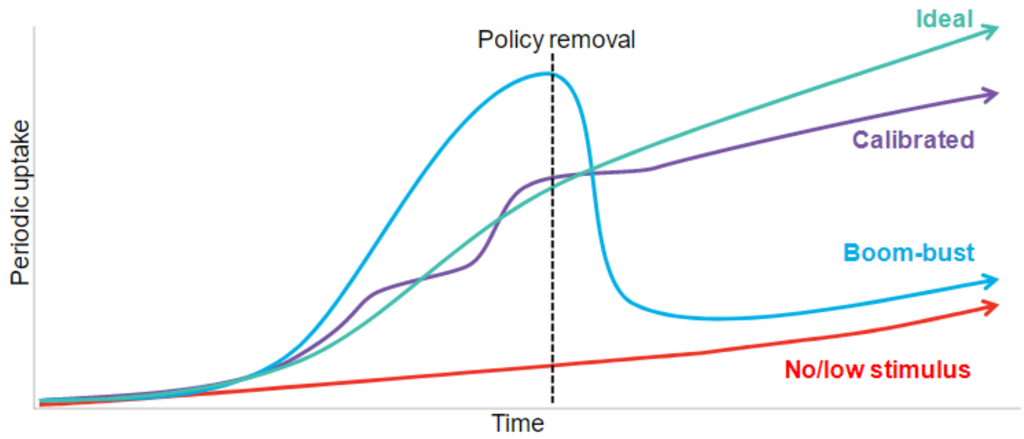
In this section, we explore what it means to get the policy and regulatory environment 'right' for customer-sited solar, and how policy makers can approach this. Policy makers should first aim to stimulate early market development and customer adoption for customer-sited solar, but do this efficiently while taking advantage of the falling costs of solar technology. They should later turn their attention to phasing in solar-plus-storage as market maturity and solar penetration rise. Separately, new-build use cases offer a low-friction, low-cost way of growing the solar market since the incremental cost of 'going solar' is much lower for a newly constructed residence or commercial building.

2.1. Early-stage market boost can bring forward economic uptake

Policy makers have often used production-based incentives (such as feed-in tariffs), capital subsidies and tax benefits to attract early investment in customer-sited solar and guide the market to the point of self-sufficiency. Since falling solar costs mean that on-site solar will ultimately become attractive in most markets, the goal is to stimulate market interest and accelerate the 'foot' of the adoption curve, and lead to a self-sustaining market that continues to grow as subsidy is removed ('**Ideal**' uptake profile in Figure 22).

In practice, policy makers have found it difficult to ignite consumer interest and stimulate market development without an unsustainable boom. Several European markets, Japan and Australia offered generous feed-in tariffs that drove immense growth ('**Boom-bust**' profile in Figure 22). Busts followed unsustainable booms when budgets ballooned, and policy support was reined in.

Figure 22: Illustrative policy-driven small-scale PV uptake profiles



Source: BloombergNEF

By contrast, markets with low reward and policy support see much slower development, driven only by intrinsic motivators until unsubsidized economics support adoption ('**No/low stimulus**' in Figure 22). For example, U.S. net metering policies have been generally less attractive than premium feed-in tariffs, particularly in states with low retail rates, and have resulted in low and slow growth. This challenge is exacerbated by high system costs. As PV costs have declined, there are more markets where unsubsidized economics are attractive, or the level of support needed is lower than it was for policy makers incentivizing growth a decade ago.

Stable policy environments foster stable industry development, regardless of the level of the incentive or mechanism design. Past experiences suggest that modest and stable compensation leads to higher customer-sited PV adoption rates than generous but unstable rates. From an incentive or mechanism design perspective there are a number of different options available (see box below). Effective policy requires careful consideration of the existing market regulation and policy structures that would help implement the most effective option(s).

Compensation nomenclature

- A **feed-in tariff, or FiT**, is a policy mechanism that compensates solar customers at a fixed rate per kilowatt hour (either on gross or net generation) and is guaranteed for a long period.
- **Net energy metering, or NEM**, allows customers to inject excess solar generation to the grid in return for a retail credit that offsets consumption at a later time or date. In principle, this has a similar effect as a net-generation FiT set at the retail price of electricity, but is capped by the size of the customer's load.
- **Generation premiums**, including adders and renewable energy certificates (RECs), provide an additional credit for each kilowatt-hour of PV generation, whether consumed onsite or injected to the grid. These can be in addition to other forms of compensation.
- An **export tariff** is the per kilowatt-hour credit issued to a solar customer for generation that is injected into the grid in the absence of a long-term feed-in tariff or net metering agreement.

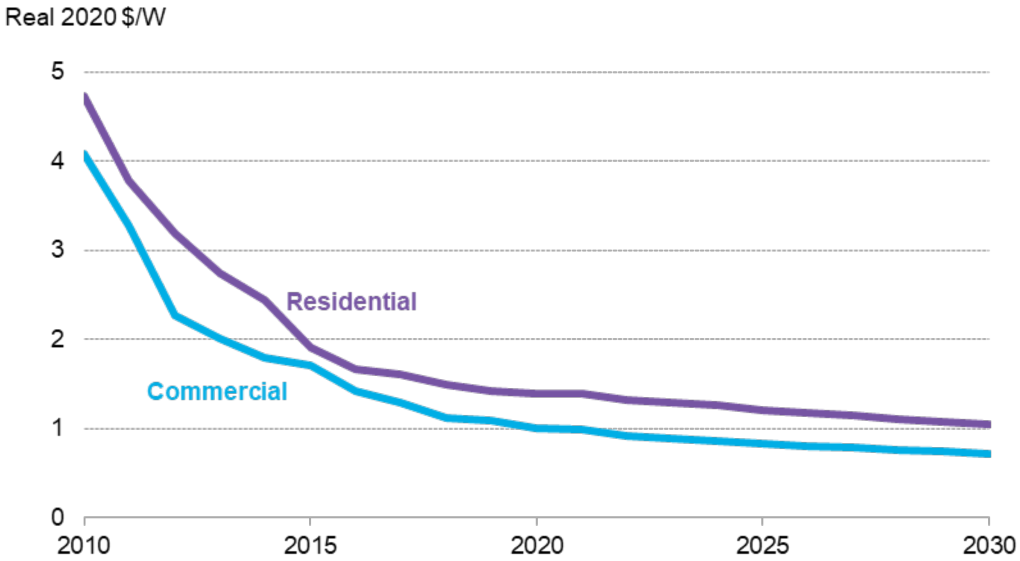
Policy designs can take advantage of falling costs

Policy makers can drive customer interest without an unsustainable boom by aligning incentives to market dynamics and putting in place automatic triggers to adjust the policy based on subscription levels ('**Calibrated**' profile in Figure 22). Some turbulence is to be expected as consumer confidence oscillates with each scheme change. For example, in France, government support is adjusted every quarter based on the volume of new capacity installed in the previous quarter, which ensures moderate growth of the customer-sited solar market.

The price of PV modules has fallen along an experience curve where costs fall by 28% for every doubling in cumulative capacity. As the market scales, it takes longer to double demand, hence cost reductions will probably slow. Continued module cost reductions will come from technology improvements and economies of scale. We expect balance-of-system costs to decline with experience, and, since they are mostly per-module, they will reduce as panel efficiency improves.

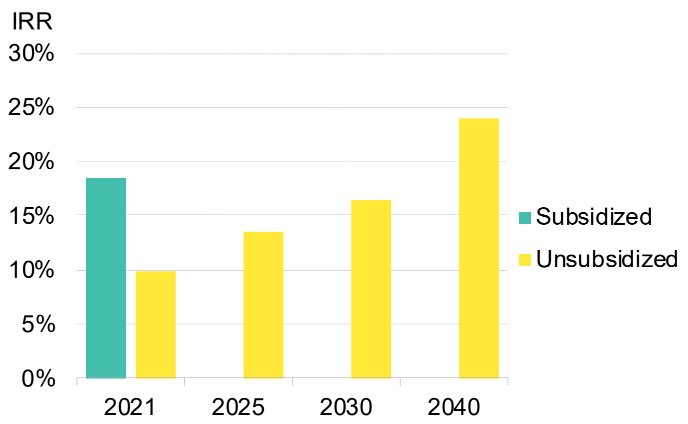
Given the continued cost declines of solar and batteries, there is an ongoing balance that needs to be struck between subsidizing for a sustainable market growth and not over-subsidizing as costs decline. Global pioneers in Europe (eg. Italy, Germany) and the mechanisms they used to encourage the solar market in 2010s are not entirely useful for policy makers today who have to design policies considering PV systems are 3.5-4 times cheaper (Figure 23). As PV comes closer to grid parity in more markets, incentives can take advantage of those continued cost declines. In France, for example, unsubsidized solar will likely become attractive to households and businesses by at least 2025, achieving a 7 and 9-year payback, respectively (Figure 24 and Figure 25). French power prices are expected to rise by 2025. And while economics varies across the country, this, coupled with declining solar capex, will mean that solar may be attractive without compensation above wholesale rates.

Figure 23: Global benchmark for customer-sited PV capex



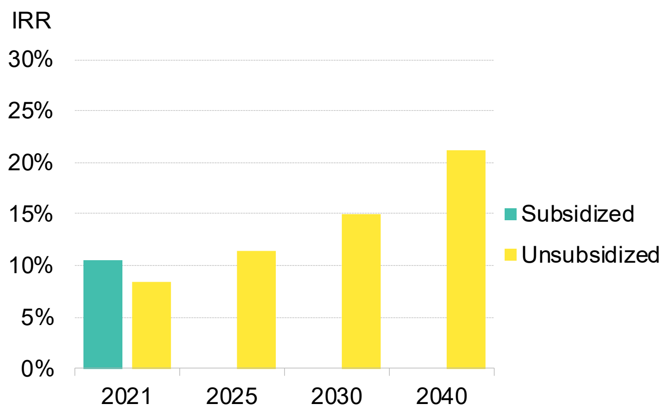
Source: BloombergNEF

Figure 24: Forecast IRRs for residential solar in France



Source: BloombergNEF. Note: 5.2kW PV system for a home consuming 5,343kWh/year on a EUR 0.16/kWh variable rate. Subsidized: compensation for exports and 'self-consumption premium' under self-consumption scheme. Unsubsidized: exports compensated at wholesale price; both scenarios assume TOU tariffs. Additional assumptions in Appendix A.

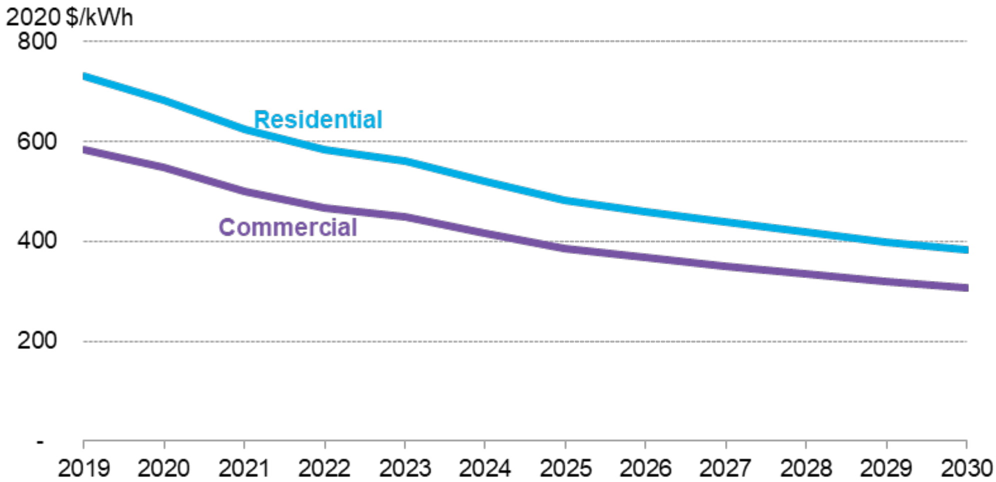
Figure 25: Forecast IRRs for unsubsidized commercial solar in France



Source: BloombergNEF. Note: 20kW PV system for an office consuming 40,000kWh/year on a EUR 0.10/kWh variable rate. Subsidized: compensation for exports and 'self-consumption premium' under self-consumption scheme. Subsidized: exports compensated at wholesale price; both scenarios assume TOU tariffs. Additional assumptions in Appendix A.

Storage system price reductions will be more rapid in the coming decade than solar, as production of lithium-ion batteries ramps up to supply the electric vehicle market. The price of lithium-ion batteries has so far followed an 18% learning rate – decreasing by 18% for each doubling in cumulative capacity.[10] Cost declines will be driven by technological improvements, manufacturing scale, competition between major battery manufacturers, greater product integration ahead of installation, and more overall industry expertise. Our benchmark for installed battery prices in 2019 was around $721/kWh for residential systems and $577/kWh for commercial systems.[11] We expect these prices to fall roughly 56% by 2050, to $317/kWh for residential and $254/kWh for commercial.

Figure 26: Global benchmark for customer-sited storage capex



Source: BloombergNEF

Heading towards an unsubsidized market

As the market takes off, subsidies need to be removed to avoid blowing government budgets and cross-subsidizing between customers. As technology costs decline, policy makers are shifting away from subsidies to more value-based payments. 'Fair-value' payments are more likely to support the next level of solar penetration because they avoid cross-subsidization and budgetary requirements remove and as markets scale.

What is cross-subsidization?

Cross-subsidization refers to when a group of customers are paying (often in an inequitable form) for the benefits that another customer is experiencing. In the case of customer-sited solar, it means customers that don't have a solar system may be indirectly paying for another customer's solar system.

This will occur if solar is valued too highly by policies that subsidize them. This could be through capital subsidies but also payments for solar generation or exports at a rate higher than what it is actually worth, such as premium feed-in tariffs or net metering. The premium is funded either by tax-payers or rate-payers. If the costs are covered by rate-payers, then non-solar customers pay a higher amount of those costs, as they also pay for more energy than their solar-counterparts. Cross-subsidization is particularly problematic since solar adopters tend already to be more well-off customers. Generous subsidies can also encourage system over-sizing that can lead to grid issues and discourage the uptake of behind-the-meter storage.

10 See *2019 Lithium-Ion Battery Price Survey* (web | terminal)

11 See *Energy Storage System Costs Survey 2019* (web | terminal)

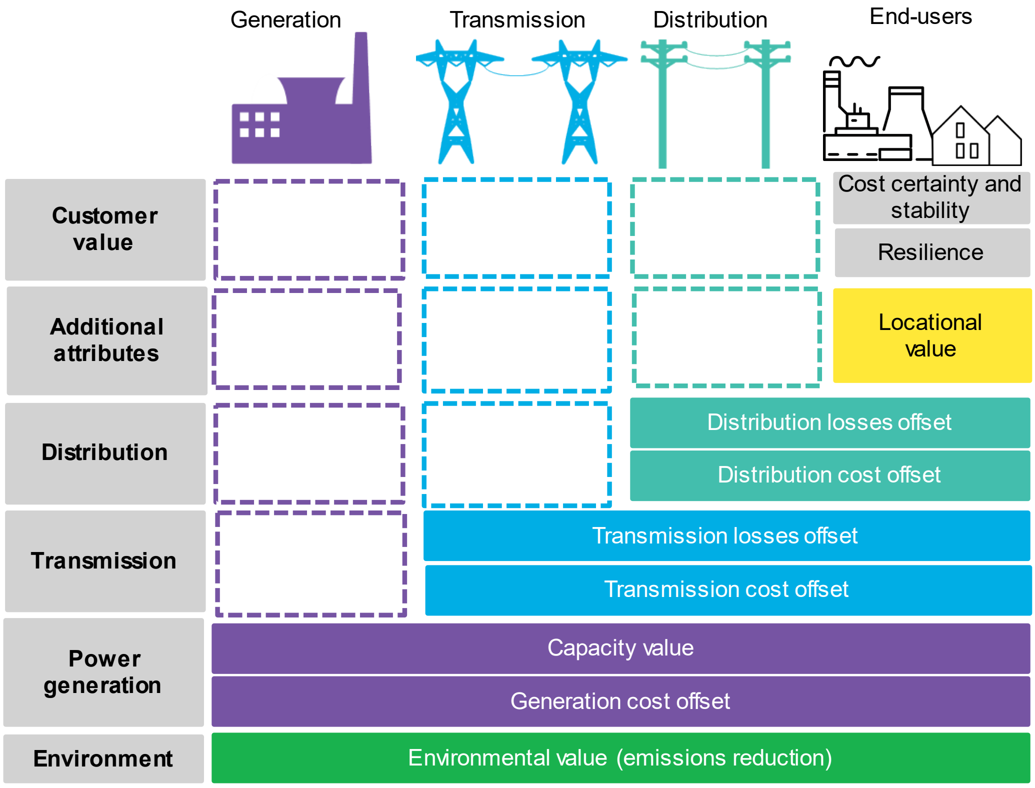
Customer-sited solar and storage provide benefits not only to the customer but also to the system. As solar penetrations rise and markets mature, the regulator's challenge is no longer to stimulate the market, but to move towards incentive structures that distribute the benefits 'fairly'.

In an effort to control cross-subsidization, many jurisdictions have moved towards compensating solar customers with the 'fair' value, or avoided costs, that small-scale PV generation provides to the grid. This can mean lowering FiTs and net metering credits to less than the retail consumption tariff, or introducing uncontracted mechanisms where compensation levels can change over time.

In many cases, this notion of 'fair value' is based on some average power price, some portion of the network charges normally incurred, and occasionally some value for the environmental attributes (for example, equivalent renewable energy credits or carbon offsets). Some exceptions exist where PV generation is deemed to deliver significant value to the network (in the form of upgrade deferral, for example) or environmental attributes are valued highly. New York state has designed a 'value of distributed energy' methodology to calculate all these components.

Figure 27 below illustrates portions of this value stack that can be chosen when evaluating the compensation mechanism. Network losses, such as those in the transmission and distribution grid, can be significant. In India, for example, 20% of electricity generated is lost through transmission and distribution inefficiencies, which could in turn be avoided through customer-sited generation. In general, value-reflective mechanisms almost always provide a weaker economic signal, and thus less impetus to adopt solar, than net metering or premium feed-in tariffs which pay at or above the retail electricity rate.

Figure 27: Layers of value stack that can be used to assess distributed energy compensation mechanisms



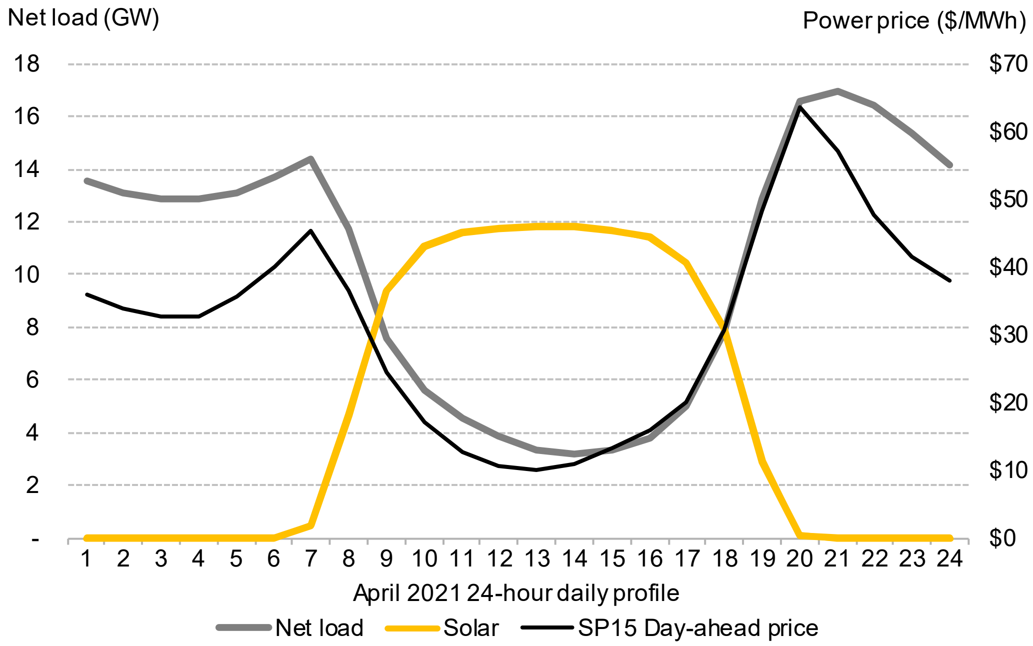
Source: BloombergNEF

2.2. Smart policy can encourage storage for deeper decentralization

Fair value payments can start to shift the balance towards solar-plus storage

As penetration of solar increases, its marginal value decreases in terms of avoiding generation and grid costs during the day. More 'zero-marginal cost' solar generation suppresses wholesale energy prices when solar is generating. In the more distributed markets, like California and Australia, power prices are depressed during the day. See, for example Figure 28 for the power market 'duck curve' in California.

Figure 28: April 2021 California power market duck curve



Source: BloombergNEF

A 'fair value'-based compensation mechanism can be designed to pass on this depressed power price to customers during solar hours. In the short term, this may mean the economics of solar self-consumption worsens. However, the fair-value mechanism should also reflect the much higher power prices during evening hours, when the sun is setting and generators need to ramp up to fill the gap as evening demand peaks. This is where storage comes in. With higher levels of solar penetration, the incremental value of more solar declines and a fair value payment can start to shift the balance towards solar-plus-storage, since using storage can be used to deliver value in times of higher net demand.

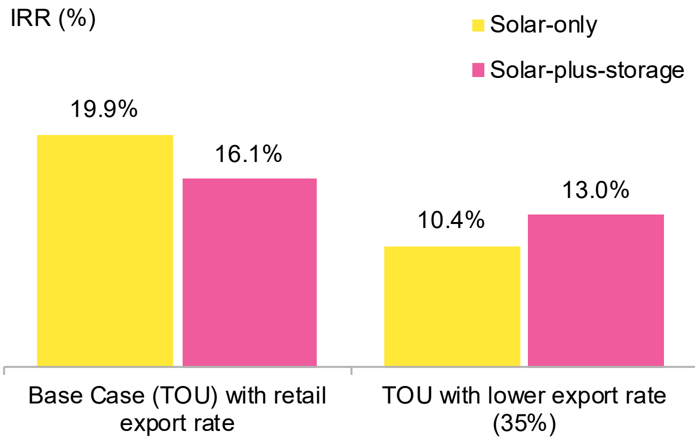
To encourage storage a few tools can be used

Lever 1: Lower export rates

When export rates are reduced to be lower than retail rates, customers are incentivized to consume solar generation on site. The higher the difference, the higher the incentive to store the generation and consume it later.

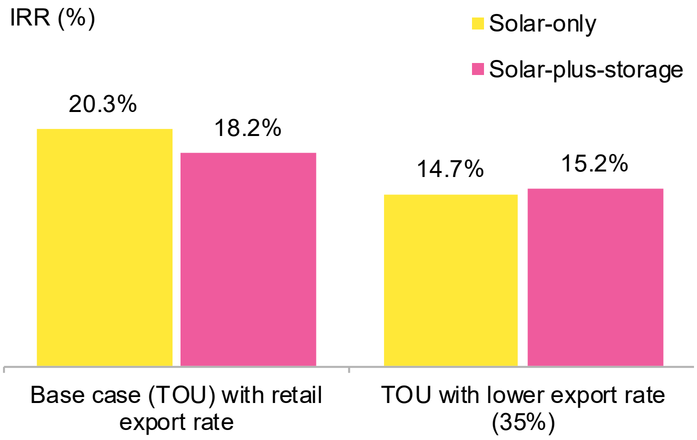
For example, in California, utilities are advocating for a reduction in net metering. Currently, customers receive a full retail credit for each kWh of solar generation exported to the grid. If regulators reduce the rate of remuneration to 35% of the retail rate, which is lower during the middle of the day than peak hours, the returns for both solar and solar-plus-storage would be lower than they currently are. However, economics for solar-plus-storage improve relative to solar-only. Residential internal rates of return are almost 3 percentage points higher when adding batteries in that scenario, equating to 8-year payback compared to 10 years without batteries. In the commercial segment, batteries just about equalize economics at 15% IRR (6-year payback) for either option. In summary, solar-plus-storage returns would withstand the change better than solar by itself, with existing subsidies in place.

Figure 29: Returns for California residential solar-only and solar-plus-storage under different export payment rates



Source: BloombergNEF. Note: Assumes 8kW PV and 5kW/14kWh battery systems, 12,000kWh/year home. Federal ITC and storage rebate applied. Base case export rate = 100% retail rate. TOU Peak: 4-9PM $0.41/kWh, Off-peak: $0.17/kWh, Additional assumptions in Appendix A.

Figure 30: Returns for California C&I solar, and solar-plus-storage with high and low export rates



Source: BloombergNEF. Note: Assumes 100kW PV and 50kW/100kWh battery systems, 166,000kWh/year office. Federal ITC and storage rebate applied. Base case export rate = 100% retail rate. TOU Peak: 4-9PM $0.36/kWh, Off-peak: $0.08/kWh). Demand charge: $23/kW. Additional assumptions in Appendix A.

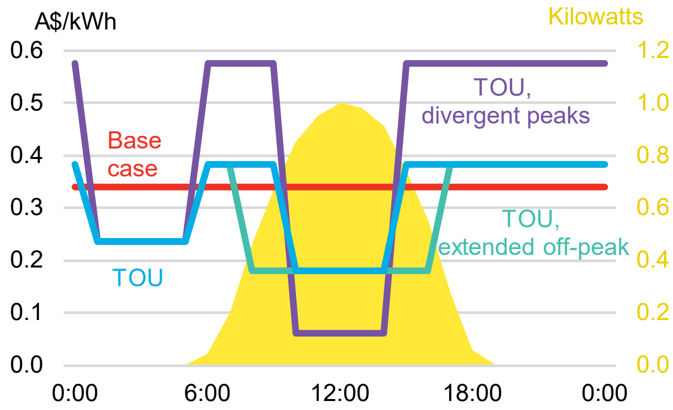
This approach, seen at a high level, is essentially to reduce the value of solar energy sent to the grid. Ultimately, when taken to a conclusion, this approach may result in introduction of rules like those in Hawaii, where limits on pushing PV energy to the grid have greatly improved the stationary battery market there, and indeed provided a better path forward for distributed renewables in an environment that is positive for both the customer and grid.

Lever 2: TOU and TOP rates, with the right design

Utilities and regulators can use time-of-use (TOU) and time of production (TOP) pricing signals to encourage the addition of storage to solar installations, but the impact depends heavily on design. Generally, regulators and utilities use time-of-use structures with lower daytime rates to reflect lower generation costs during solar hours (relative to higher generation costs during peak evening hours when thermal generators need to ramp up). Lower daytime retail rates reduce the value that is offset through self-consumption at the time solar is generating. At the same time, higher evening or early-morning rates increase the value of solar energy stored in a battery for later use. Together, these TOU features can encourage the addition of storage.

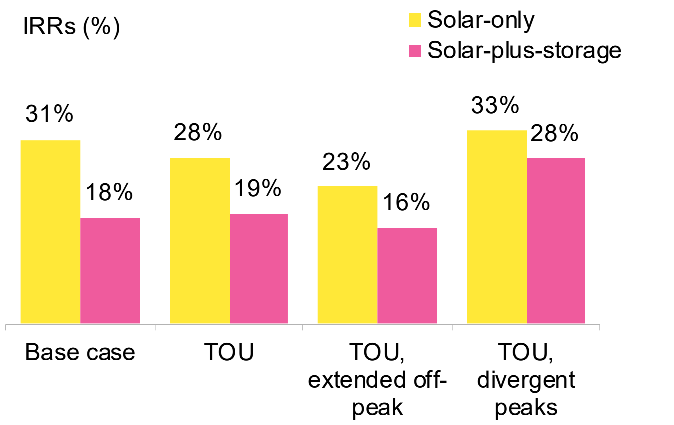
In South Australia, where 39% of households already have solar, the distribution network service provider has made it mandatory for any customer with a smart meter to be charged a TOU network tariff. Retailers often pass on this varying rate structure in the final customer-facing retail rate. The current design has only a small impact on solar-only IRRs, reducing them from 31% on the base-case flat tariff to 28% on a TOU tariff, maintaining payback at 4 years (Figure 32). As solar additions continue, the value of daytime solar production will continue to decrease, while flexibility will become more important. Utilities will be more likely to make daytime off-peak periods longer, while also increasing the price difference from peak periods, both of which will impact the returns of solar and storage. These effects are illustrated in Figure 31 and Figure 32 with our 'extended off-peak' and 'divergent peaks' scenarios. The divergent peak scenario, which has the highest difference in peak/off-peak rates, gives an attractive IRR for solar-plus-storage, increasing the IRR of a solar-plus-storage system to 28% and reducing the payback period from 7 to 4 years.

Figure 31: Retail tariff scenarios for South Australia households



Source: BloombergNEF

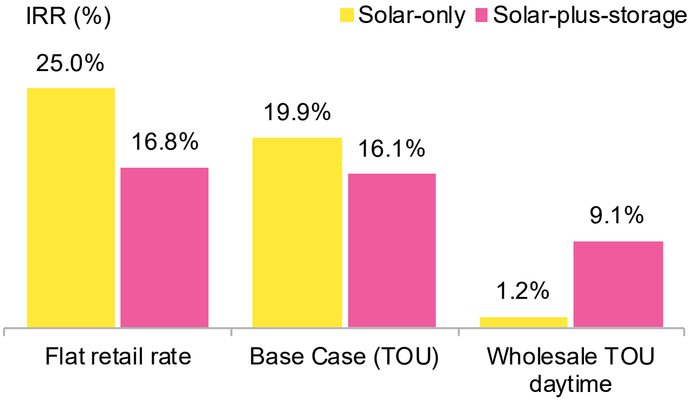
Figure 32: IRRs of South Australia residential behind-the-meter solar and storage under different retail tariff scenarios



Source: BloombergNEF. Note: Assumes 6kW PV and 12kWh battery systems, home consuming 6,220kWh/year. Rate assumptions in Figure 31, additional assumptions in Appendix A.

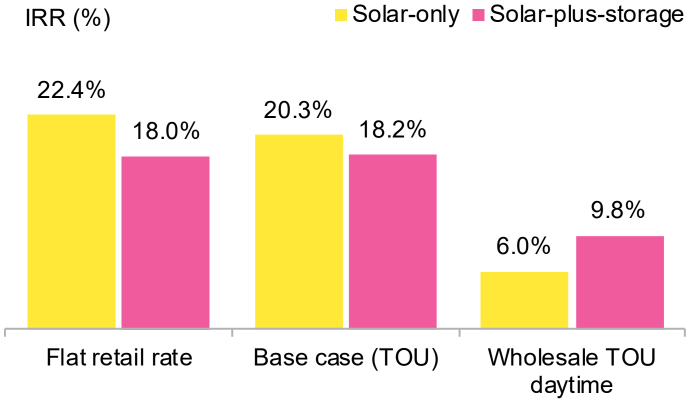
In California, time-of-use rates are compulsory for solar customers. Under the current TOU rate structure, customers are more inclined to add storage to their new customer-sited solar, compared to when rates were flat (see Figure 33 and Figure 34). This is because returns for solar-only drops when TOU is applied, while the economics for solar-plus-storage remains almost the same. Solar-plus-storage yields the same returns in both scenarios because the battery charges from solar and helps to offset the highest electricity prices during the evening. The effect would be even more marked if daytime rates were even lower – at wholesale rates, customers would be much better off adding storage (third scenario in Figures 23 and 24). Returns for solar-plus-storage would be just under the threshold of 10% IRR or 8-year payback period.

Figure 33: Return comparison for California residential solar-only and solar-plus-storage with different TOU structures



Source: BloombergNEF. Note: Assumes 8kW PV and 5kW/14kWh battery systems, 12,000kWh/year home. Federal ITC and storage rebate applied. Base case export rate = 100% retail rate. Flat retail rate; $0.25/kWh. TOU Peak: 4-9PM $0.41/kWh, Off-peak: $0.17/kWh, Wholesale TOU daytime: Peak: 4-9PM $0.44/kWh, Off-peak: $0.01/kWh. Additional assumptions in Appendix A.

Figure 34: Return comparison for California commercial solar-only and solar-plus-storage with different TOU structures



Source: BloombergNEF. Note: Assumes 100kW PV and 50kW/100kWh battery systems, 166,000kWh/year office. Federal ITC and storage rebate applied. Base case export rate = 100% retail rate. Flat retail rate: $0.13/kWh. TOU Peak: 4-9PM $0.36/kWh, Off-peak: $0.08/kWh). Wholesale TOU daytime: Peak: 4-9PM $0.40/kWh, Off-peak: $0.01/kWh). $23/kW demand charges applied to all scenarios. Additional assumptions in Appendix A.

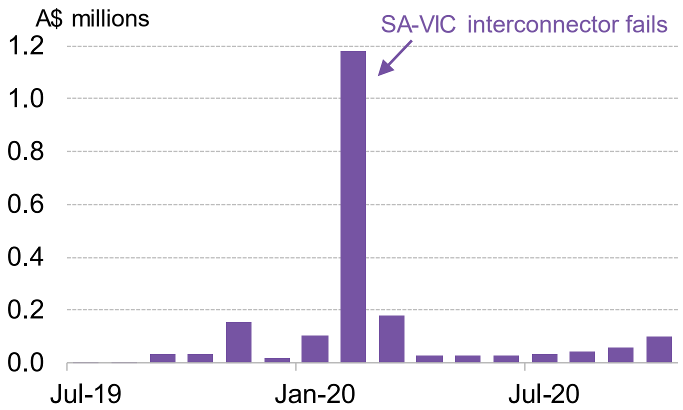
Lever 3: Payments for grid and system services

Solar-plus-storage can provide services to the power system and grid. Utilities, energy retailers or aggregators can aggregate the power from the batteries for capacity, energy or network services and either earn revenues or achieve cost savings. They share the value with customers through payments, subsidies, discounts or bill credits.

Payments for batteries providing such services improve the returns of solar-plus-storage and make batteries more appealing to both residential and commercial customers. Meanwhile the returns for solar-only remain unchanged -- the additional incentive for storage helps encourage more solar-plus-storage additions.

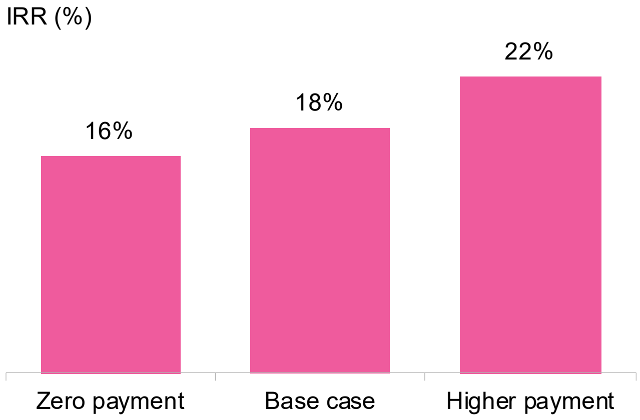
For example, Australia is one of the world leaders in virtual power plant (VPP) development, with over 50 active VPPs. Customer incentives for participating can be lucrative in some cases but the future value is uncertain. Assuming a base case where customers are paid $50/year per kilowatt enrolled in a VPP, residential solar-plus-storage IRRs are slightly higher than without this aggregation service (18% compared to 16%, or 6-year payback in both cases). At the upper end, higher payments of $100/kW/year further increase solar-plus-storage IRRs to 22%, still managing a 6-year payback.

Figure 35: Monthly Frequency Control and Ancillary Services (FCAS) market revenues for Tesla's VPP



Source: BloombergNEF, AEMO

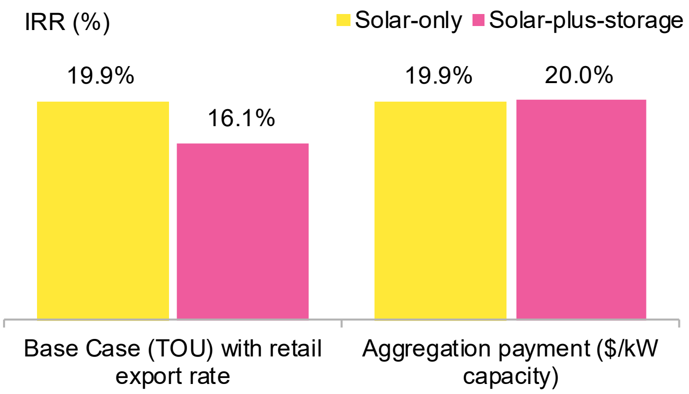
Figure 36: IRRs of South Australia residential solar-plus-storage under different aggregation payment scenarios



Source: BloombergNEF. Note: Assumes 6kW PV and 12kWh battery systems, home consuming 6,220kWh/year. Base case: aggregation payment A$65/kW/year. Higher aggregation: payment A$140/kW/year. Retail rate at A$0.34/kWh and export rate at A$0.12/kWh. Additional assumptions in Appendix A.

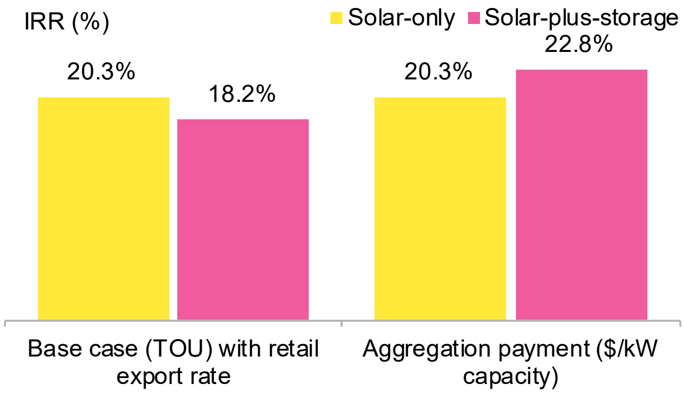
In the U.S., California was one of the first states where utilities, system operators and distributed energy providers piloted aggregation programs for customer-sited solar and storage. A $100/kW/year payment improves IRRs for residential solar-plus-storage and narrows the gap with solar-only for both households and businesses (see Figure 37 and Figure 38). For businesses, these payments would make solar-plus-storage (with an IRR of 18.2%) more attractive than solar-only, when combined with existing storage rebates.

Figure 37: Returns for California residential solar with and without aggregation payments for batteries



Source: BloombergNEF. Note: Assumes 8kW PV and 5kW/14kWh battery systems, 12,000kWh/year home. Federal ITC and storage rebate applied. Export rate = 100% retail rate. Base Case (TOU): Peak: 4-9PM $0.41/kWh, Off-peak: $0.17/kWh, Aggregation payment: $100/kW capacity/year assumed for residential solar and storage.

Figure 38: Returns for California C&I solar with and without aggregation payments for batteries



Source: BloombergNEF. Note: Assumes 100kW PV and 50kW/100kWh battery systems, 166,000kWh/year office. Federal ITC and storage rebate applied. TOU rate: Peak: 4-9PM $0.36/kWh, Off-peak: $0.08/kWh. Export rate = 100% retail rate. $23/kW demand charges applied. Aggregation payment: $100/kW capacity/year for commercial solar and storage.

Regulators and market operators are making moves to improve market access. In 2020, the U.S. Federal Energy Regulatory Commission issued an order requiring wholesale market operators to accommodate DERs in their markets. The U.K. already accommodates aggregated resources, and in recent years the transmission system operator has removed some barriers, such as removing the requirement for a supply license in the Balancing Mechanism and reducing the minimum size to 1MW in the capacity market. The Australian Energy Market Operator has removed participant-type limitations for virtual power plants in ancillary service markets. It is now implementing a mechanism for commercial and industrial demand response in energy markets. In 2020, Shandong became the first province in China to allow virtual power plants in its spot, back-up capacity and ancillary service markets.

Lever 4: Consider demand charges design (especially for C&I)

Peak demand charges are fees more commonly applied to commercial and industrial customers, structured as a $/kW charge for each kW consumed at the time when they are withdrawing the most power (kW) from the grid (usually averaged over 15 minutes) over the course of their billing periods. Demand charges help utilities make up the expenses incurred by building transmission and distribution (T&D) capacity to meet peak demand.

Utilities need to have T&D capacity that meets the maximum possible demand as opposed to just the average demand to ensure that all customers will have reliable service. Some infrastructure will only be used to its full extent at times of very high demand, yet it must still be built, maintained and paid for like all other infrastructure. Demand charges are calculated based on customers' peak usage, incentivizing them to reduce such peaks, and therefore lessening the need for additional T&D capacity.

Peak demand charge reduction is a major driver for commercial storage uptake, such as in California, New York and Ontario. Customers use batteries to shave peak demand and reduce the demand charge component of their utility bill, which is typically based on the building’s highest demand in a month.[12] The value of doing so depends on how high the demand charge is, how it is designed (as in, when and how is it applied) and how peaky the load is.

In Australia, businesses already face demand charges, but the returns are still generally low for commercial solar-plus-storage. With network companies’ revenues continuing to be eroded by solar, discussions have centered around increasing the value of their demand charges, in an effort to offset lost revenue. If demand charges were increased by 50% the economics of solar-plus-storage would be improved (see Figure 39 and Figure 40). For users with an office-like profile, the IRR of solar-plus-storage is boosted from 5.5% to 8.1% (reducing the payback period from 13 to 9 years), which starts to look attractive. These higher demand charges are still not enough to make solar-plus-storage a worthwhile investment for warehouses and manufacturers in the modelled scenarios, due to their different load profiles (note that rates, demand profiles and system sizes can vary significantly and mean economics will vary across Australia).

Note that batteries may be an economic option for demand charge management as a standalone asset, without solar. Stacking the demand charge reduction savings, time-of-use rate optimization

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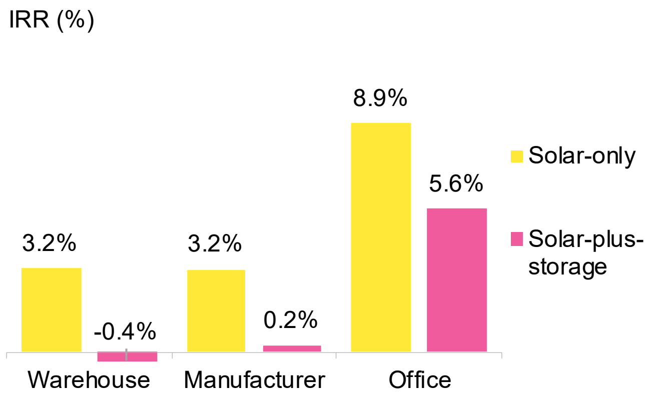
12 A demand charge, often in $/kW per month, is typically based on a building’s highest average demand in any 15-minute period, in kW, each month. Both the structure and the rate will vary by country – in the U.K. for instance this is not based on monthly peak demand but on three half-hour settlement periods with highest system demand between November and February, separated by at least 10 clear days. The underlying purpose of the tariff is similar though.

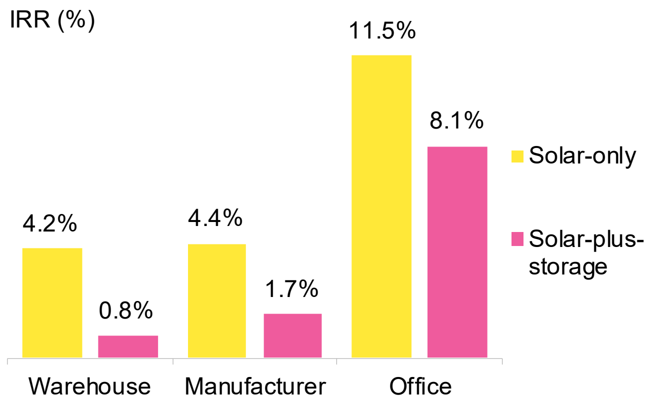
in addition to aggregation payments and resilience benefits would improve relative economics of the battery addition, while in the future, its lower cost will also make its proposition more attractive.

Figure 39: IRRs of New South Wales industrial behind-the-meter solar and storage with different user profiles



Source: BloombergNEF. Note: 300kW PV and 500kWh battery systems, 1GWh/year load. Variable peak: A$0.12/kWh ($0.09/kWh), Shoulder: A$0.05/kWh ($0.04/kWh), Off-peak A$0.03/kWh ($0.02/kWh) - peak times vary depending on month. Demand charge: A$12/kW/month ($9/kW/month). Exports curtailed. Additional assumptions in Appendix A.

Figure 40: IRRs of New South Wales industrial behind-the-meter solar and storage with different user profiles and a 50% increase in demand charges



Source: BloombergNEF. Note: 300kW PV and 500kWh battery systems, 1GWh/year load. Variable peak: A$0.12/kWh ($0.09/kWh), Shoulder: A$0.05/kWh ($0.04/kWh), Off-peak A$0.03/kWh ($0.02/kWh) - peak times vary depending on month. Demand charge: A$18/kW/month ($14/kW/month). Exports curtailed. Additional assumptions in Appendix A.

2.3. Removing barriers can open up solar markets

Aside from the economics, there are a number of other barriers that can impede customer solar adoption. In this section we briefly discuss these barriers, and available solutions that can lower them.

Occupancy barriers

There are a number of barriers associated with tying investments to the specific tenant(s) of the building (see Table 1 below). Potential solutions include community solar programs and virtual net metering/collective self-consumption. They provide opportunities for other customers located nearby essentially to buy the power generated, which reduces the emphasis of all benefits accruing to building occupants.

Table 1: Tenancy barriers

Barrier	Description
Split incentives	In rental properties, benefits of solar accrue to tenants and the landlord has no incentive to invest in solar.

Short tenors/property churn	Where properties are regularly turned over, with property ownership and tenancy short, the owner has less incentive to invest in a 25-year solar asset. They may be able to recover the investment through a higher property sale price.
Mismatched load and space	Some large properties have more space for solar than they do load to consume the generation. This is particularly problematic in markets where exports are not allowed (as for most businesses in Australia) or not well remunerated.
Shared roof space	Where roof space is shared by multiple customers. This may occur in multi-story apartments, shopping centers, office buildings, etc. Exacerbated by urbanization: Over time, urbanization will increase the share of multi-story apartments, further limiting the ability for households to install their own solar. Markets that have advanced rooftop solar have typically addressed this, but this can sometimes be a barrier when tenants do not agree in how to use shared roof space.

Source: BloombergNEF

Financial barriers

Removing barriers to third-party ownership can help unlock solar investment for more customers. Despite falling costs, a solar system is a large upfront outlay. Households and businesses may either lack the funds to invest in solar themselves or have alternative investments they'd prefer to make. Instead of investing in systems themselves, some organizations turn to third-party ownership models and enter into power purchase agreements (PPAs).

Structuring policies to incentivize third-party finance is a double-edged sword. On one hand, additional revenues provided by renewable energy certificates, feed-in tariffs or investment tax credits reduces the potential income loss from off-taker bankruptcy. According to a review by the Berkeley Lab, 30-70% of commercial solar projects in places in the U.S. with generous state subsidies, such as SRECs or feed-in-tariffs, are third-party owned. On the other hand, complex policies such as tax credits and non-uniform, changing subsidies often require a specialized investor – which potentially locks out investments from smaller investors or the customer themselves.

Utility and regulatory push-back

There are many examples of utilities demonstrating reluctance in supporting customer-sited solar. This has often led to onerous permitting rules, penalties and charges; and export limits that make solar more difficult to install, more expensive and less attractive.

Utilities may object to customer-sited solar for a variety of reasons. There may be a lack of incentive for utilities to encourage customers to generate their own energy or allow them to deliver services that may be useful for them to manage the grid. Additionally, utilities may find themselves unable to recoup grid investment and maintenance costs when customers adopt solar in large numbers, due to the lack of proper rate design. In a worse-case scenario, utilities' revenues may be tied directly to volumes of electricity sold, hence they may not want customers to defect load.[13] In any case, realigning utility incentives could be an effective way to address utility pushback. For example, performance-based incentives can directly incentivize utilities to speed up interconnection, green the grid etc.

Some utilities prefer solar paired with batteries to limit injection into the grid, which can be particularly warranted in high-penetration markets such as Hawaii. In some U.S. markets, notably Florida where penetration is low, utilities had historically pushed back against net metering and

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13 Often, however, regulation ensures that utility profits are not tied to selling electricity (kWh). Private network operators typically own profit over the investment and maintenance of the grid instead.

third-party owned systems, a stance which was disproportional to the value that customer-sited solar could otherwise bring. Removing penalties and simplifying permitting processes have proven to allow market growth. For example, Spain's small-scale solar market boomed in 2019 following the removal of Spain's 'sun tax'[14] on self-consumption and the simplification of connection and permitting processes for both households and businesses.

Table 2: Utility and regulatory push-back

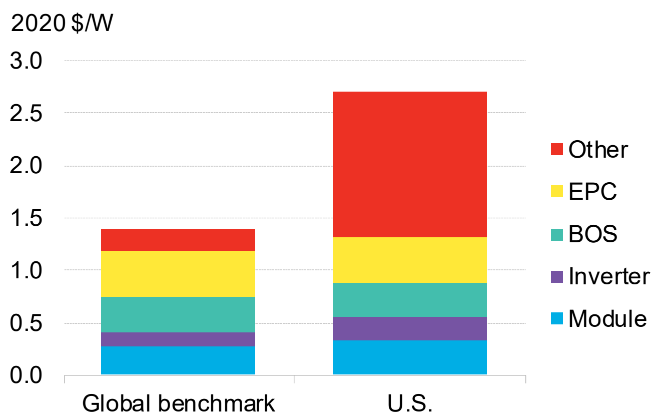
Barrier	Description
Onerous permitting rules	In some markets, utilities impose interconnection rules that make the process of adopting solar complex, long and expensive. Non-standardized rules across different states and regions makes it difficult for installers to scale. This is a challenge faced by the solar market in the U.S.
Penalties and charges	Standby charges, solar self-consumption charges. Eg, Spain 'sun tax'
Export limits	Utilities may restrict or ban solar exports to the grid. In some cases, such as Australia and Hawaii, this is an attempt to reduce impact of solar on the grid and to allow more solar to connect. In others, it is an attempt to undermine the attractiveness of solar.

Source: BloombergNEF

2.4. New construction

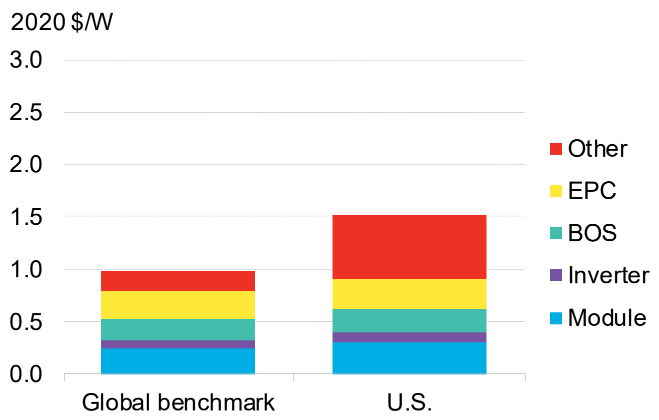
Installing solar when buildings are constructed is cheaper than retrofitting to existing buildings and delivers a clear value proposition. Solar companies can cut down on soft costs, including sales, marketing and permitting, by partnering with home builders. These soft costs make up a large component of total solar costs in some markets.: in the U.S. they account for 51% ($1.39/W) of the final residential solar price and 39% ($0.6/W) of final commercial solar price (see Figure 41 and Figure 42). By comparison, soft costs make up 14% of BloombergNEF's global benchmark for residential PV capex.

Figure 41: Residential PV capex breakdown, 2021



Source: BloombergNEF

Figure 42: Commercial PV capex breakdown, 2021



Source: BloombergNEF

Installing solar panels on new homes could also save on solar construction costs, such as labor and scaffolding. In regions where scaffolding is commonly used for solar installations, it can

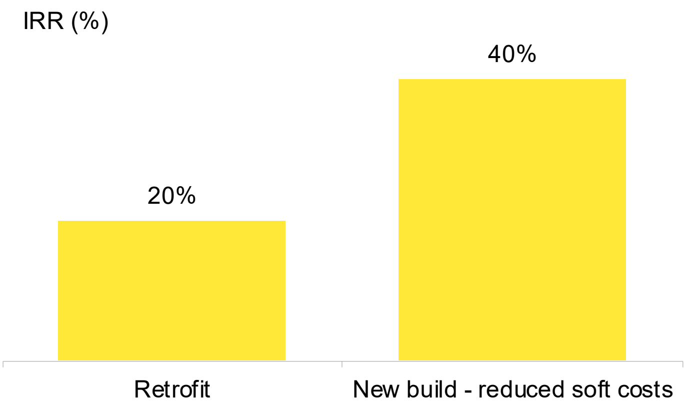
[14] Sun tax was an export charge placed on a customer that exported power to the grid (at around half the retail tariff).

contribute large costs which can be reduced by installing at the same time as the roof. However, labor cost savings depend on roofers being willing and able to install solar panels. Builders and roofing companies in the U.S., for example, prefer to subcontract the entire panel installation and electrical work to solar installers due to a lack of expertise and the complexity of the solar supply chain. Examples include partnerships between SunPower and KB Home or Sunnova's recent acquisition of SunStreet, the solar installation business of new-home builder behemoth Lennar.

Returns tend to be very high for new construction solar, making it a 'no-brainer'. In our analysis, we assume that property developers pass on full solar installation costs, which are lower than for retrofits, to homeowners who can then recover the investment through utility bill savings and export credits. This allows us to measure IRRs in the same way as for the retrofit use cases shown above.

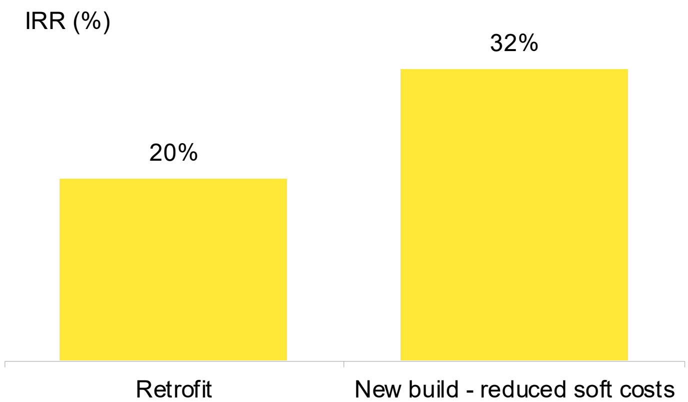
In California, we estimate that returns on new-build residential solar are around 20 percentage points higher than for retrofits. If solar companies can reduce their soft costs by 80% and install residential solar for $1.6/W, then returns for the final household would be 40%, equivalent to a 3-year payback, down from 6 years (Figure 43). In absolute terms, the installation cost of an 8kW PV system would go down to $12,700 compared to $22,000 when retrofitting. When building a new home, the builder or homeowner may also be more willing to pay for it, considering it's a smaller cost compared to overall investment of building the new home. Comparatively, for commercial solar, an 80% soft cost reduction wouldn't have as big an impact. Returns would increase to 33%, up from 20% bringing the payback period from 4 to 3 years.

Figure 43: Returns for residential solar in California – retrofit versus new construction



Source: BloombergNEF. Assumes 8kW PV system, 12,000kWh/year home. Federal ITC applied. Export rate = 100% retail rate. TOU rate: Peak: 4-9PM $0.41/kWh, Off-peak: $0.17/kWh. Retrofit capex = $2.8/W, New construction capex = $1.6/W. Additional assumptions in Appendix A.

Figure 44: Returns for commercial solar in California – retrofit versus new construction

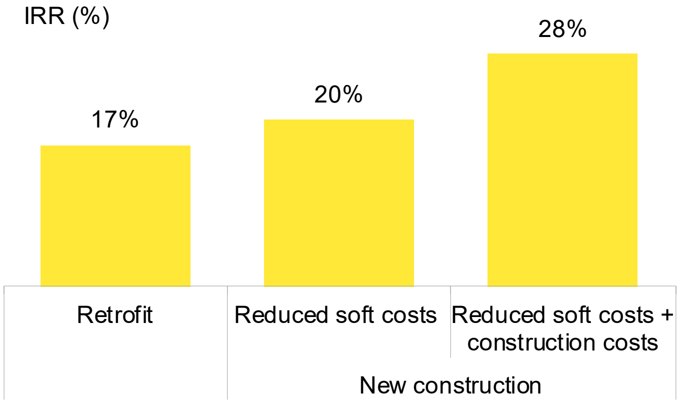


Source: BloombergNEF. Assumes 100kW PV, 166,000kWh/year office. Federal ITC rebate applied. TOU rate: Peak: 4-9PM $0.36/kWh, Off-peak: $0.08/kWh. Export rate = 100% retail rate. $23/kW demand charge. Retrofit capex = $1.6/W, New construction capex = $1.0/W. Additional assumptions in Appendix A.

In most other markets, soft costs make up a smaller part of PV capex and the returns will rely heavily on construction cost savings. In France, for example, 80% lower soft costs would decrease residential solar returns to a 5-year payback, down from 6 years (or improve IRRs to 20%, up from 17%, Figure 45). If solar installers can also save $0.25/W in labor and scaffolding costs, then new construction returns would increase much more to 28%, or 4-year payback. This is a full 10 percentage points higher return than the retrofit case.

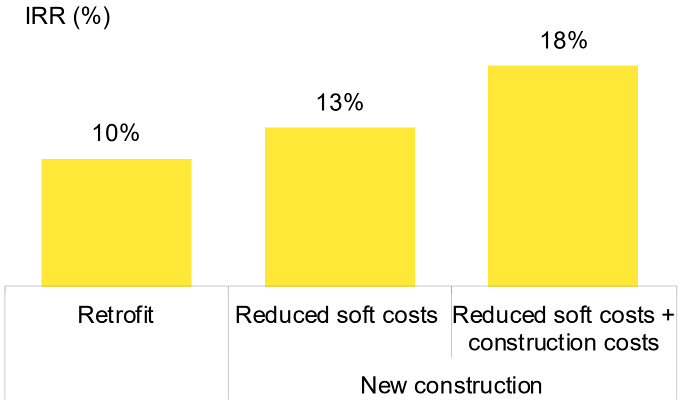
For commercial solar, the story is similar, with 18% returns, up from 10% (reducing payback from 9 to 6 years) in the retrofit case (Figure 46).

Figure 45: Returns for residential solar in France – retrofit versus new construction



Source: BloombergNEF. Note: 5.2kW PV system for a home consuming 5,343kWh/year on a EUR 0.16/kWh ($0.19/kWh) variable rate. Subsidized compensation for exports and 'self-consumption premium' under self-consumption scheme, Retrofit capex = $1.4/W, Reduced soft costs capex = $1.0/W, Reduced construction costs = $1.0/W. Additional assumptions in Appendix A.

Figure 46: Returns for commercial solar in France – retrofit versus new construction



Source: BloombergNEF. Note: 20kW PV system for an office consuming 40,000kWh/year on a EUR 0.10/kWh variable rate. Subsidized compensation for exports and 'self-consumption premium' under self-consumption scheme. Retrofit capex = $1.0/W, Reduced soft costs capex = $0.8/W, Reduced construction costs = $0.7/W. Additional assumptions in Appendix A.

Despite the clear value proposition, builders are not commonly adding solar to new buildings. This is because selling solar systems is not their core business and builders are also often mainly defaulting to incumbent building design and engineering choices when making construction decisions, while ensuring they comply with most recent building codes. Hence, government mandates can be an effective way to ensure that these investments are made.

France has decreed new rooftops at commercial sites to have solar since 2015. In 2020, we've seen a wave of additional regions follow suit. Germany implemented rooftop solar in 2020 for non-residential buildings, and in Berlin this will be extended to most new buildings from 2023, and as of 2020 California was the first U.S. state to require rooftop solar on every new single-family building. In August 2021, the California Energy Commission expanded the rooftop solar mandate to include commercial and multi-family apartment buildings as well, pending approval by the state's Building Standards Commission. South Miami city in Florida also has a mandate for solar on new homes.

Section 3.

Case studies

Section 3. Case studies

This section reviews the state of the market in France, Spain, Australia, New Jersey (U.S.) and California (U.S.). For each market, BloombergNEF has conducted sensitivity analyses to illustrate how different policy and regulatory approaches affect the customer economics of solar (with and without storage).

3.1. Markets at different stages

As discussed above, policy objectives should reflect the stage of each market: early stage markets have different needs compared to more mature markets.

The five markets we analyzed are at different stages of market development, and thus provide interesting case studies on how these different objectives can be achieved. France and Spain are both in early market development, with different policy frameworks. In France, stable growth is supported by quota-based feed-in tariff and subsidy schemes whereas Spain is growing largely unsubsidized at this point. New Jersey is grappling with reducing production-based incentives as the market scales. California and Australia are the most advanced markets and face immediate solar integration issues due to high penetrations causing grid challenges.

Table 3: Summary of case study policy implications

Market	Solar penetration (W per capita)	Current policy priority	Policy implication
France	Residential: 23 C&I: 50	Early market development	Quota-based solar support currently ensures stable growth of customer-sited solar in France. The 'self-consumption' scheme is a more sustainable policy compared to the gross FiT scheme as it lessens the incentive for customers to over-size systems and provides more incentive for them to shift demand or add a battery to consume more solar generation on-site. As the solar segment grows and costs decline, policy makers should be able to shift subsidies from solar to storage and kick-start the local residential storage market. Commercial storage will require more support -- avoidable demand charges would boost the attractiveness of storage.
Spain	Residential: 10 C&I: 45	Early market development	Solar in Spain is already growing largely unsubsidized, after the removal of a 'sun tax' and onerous permitting processes. Further solar cost declines should improve economics. Battery storage will likely need support in the near term to foster market development. Demand charges could improve the outlook for commercial storage.
New Jersey	Residential: 131 C&I: 38	Fair value	Generous export incentive has helped to support historical growth. The regulator is considering a reduction in the incentive, which would erode new build. In addition, reducing net metering could nudge customers to add storage. Policy makers could offset the reduction by allowing for automated permits and interconnection, opening up markets for grid and system services and providing incentives to create a higher pool of qualified labor. Permitting, interconnection and labor market incentives translate into lower upfront costs, while aggregation payments provide an additional revenue stream for batteries.
California	Residential: 213 C&I: 119	Fair value and integration	California policy makers are prioritizing grid stability and reducing cross-subsidization. Lower export rates can be used to nudge customers to add storage to solar installations. Returns for residential solar and solar-plus storage could remain attractive if policy makers also put in place reforms to ensure access to payments for grid and system services, faster permitting and labor availability.

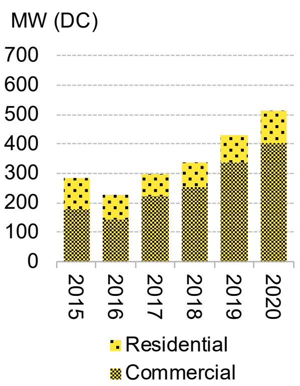
Market	Solar penetration (W per capita)	Current policy priority	Policy implication
Australia	Residential: 449 C&I: 97	Integration	The priority for policy makers in Australia is to manage solar exports and integrate higher penetrations of customer-sited solar. Storage subsidies, such as those in South Australia, are helping to kick-start the storage market. Tariff design will be key to the next stage of market development – supporting ongoing addition of storage without subsidization. TOU tariffs for households will enable solar-plus-storage to be valued and earn returns, even as daytime value of solar generation and utilities try to reduce solar exports. Meanwhile demand charges for C&I customers will be central to storage uptake in that sector and could help integrate more solar.

Source: BloombergNEF. Note: France, Spain and Australia solar penetration as at end 2020. New Jersey and California as at Feb 2021.

3.2. France

Quotas on government support ensure moderate growth of customer-sited solar

Figure 47: Customer-sited solar capacity additions in France



Source: BloombergNEF

Solar uptake has grown in France in both the commercial and residential segments (Figure 47), as PV capex has fallen and awareness among consumers has risen. At the moment, the economics rely on government support. There are two main government programs, both of which are based on a quota mechanism that adjusts support every quarter based on the volume of new capacity installed in the previous quarter, ensuring moderate growth of the customer-sited solar market. If build volumes fall short or go above what is considered in line with the yearly target, the rates are adjusted to help slow or encourage build. The government has steadily reduced support as the country meets small-scale solar installation quotas.

The first government program is a generous gross feed-in tariff (FiT) scheme, which has driven customer-sited solar build. It compensates systems up to 100kW (expected to be raised to 500kW by 4Q 2021) for every kilowatt-hour generated. Systems under the scheme are required to export all of their generation. The current rate is for systems between 3 and 9kW is 15 euro cents/kWh, while systems up to 100kW receive a FiT of around 10 euro cents/kWh. Compensation rates are designed so it pays below the peak and above the off-peak retail tariff for both segments. Tariffs are guaranteed for 20 years and indexed to inflation.[15]

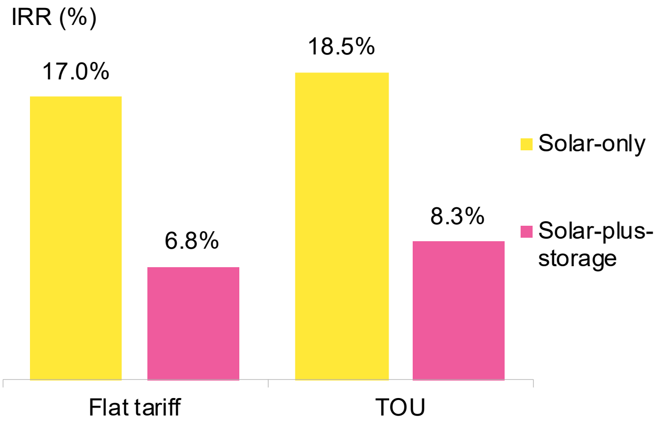
The second program is an opt-in alternative to the gross FiT. Introduced in 2017, the program encourages consumers to size their systems more conservatively. Consumers can elect for a self-consumption scheme, where they receive a lower rate for excess energy fed into the grid than they would under the FiT. The rate is below the retail power rate, currently 10 eurocents/kWh for systems of 9kW or smaller, and 6 eurocents/kWh for larger systems up to 100kW. Customers may choose this option, particularly if they can consume enough of their generation on-site, because they receive an additional capacity-based payment for the first five years of operation (called an "investment premium" or "self-consumption premium"), which acts as a sort of capex support mechanism (currently 56 euros/kW/year for 3-9kW systems; 32 euros/kW/year for 9-36kW systems; and 16 euros/kW/year for systems up to100kW). The 'self-consumption premium' is adjusted to achieve government quotas for solar additions.

[15] Terre Solaire

The 'self-consumption' scheme lessens the incentive for customers to over-size systems compared to the gross FiT scheme and provides more incentive for them to shift demand or add a battery to consume more solar generation on-site. We used the 'self-consumption' scheme when modelling customers in our analysis.

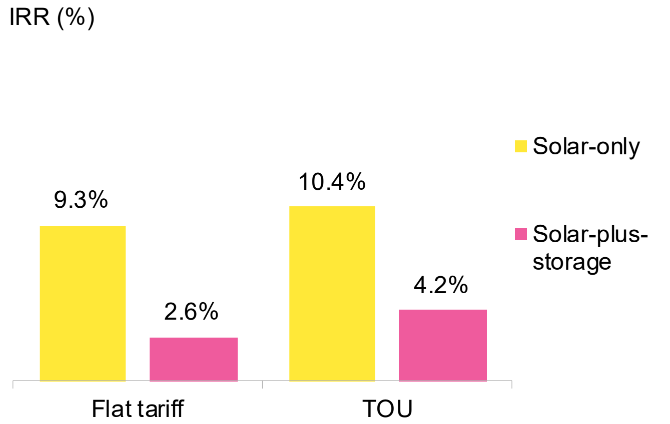
With feed-in tariffs under France's 'self-consumption' scheme, households on a time-of-use (TOU) rate can achieve a payback of 5 years on solar projects (IRRs of 18.5%, Figure 48), while businesses on a TOU rate can achieve an IRR of 10.4%, or a 9-year payback (Figure 49). Without government support, households and businesses would comparatively have longer paybacks, 10 years and 11 years respectively with lower IRRs (9.8% and 8.5%, respectively).[16] Customers on current TOU tariffs benefit slightly more from installing customer-sited solar than those opting for flat tariffs. This is because current peak rates are from 6am to 10pm and solar can help customers reduce grid consumption during many of these hours.

Figure 48: Economics for residential solar and solar-plus-storage installed in France, 2021



Source: BloombergNEF. Note: 5.2kW PV and 7.2kWh battery systems, 5,354kWh/year household. Flat retail rate: EUR 0.16/kWh ($0.19/kWh). TOU: Variable peak: 6AM-10PM, EUR 0.18/kWh ($0.21/kWh), Off-peak: 10PM-6AM EUR 0.13/kWh ($0.15/kWh). Assumes compensation under self-consumption scheme. Additional assumptions in Appendix A.

Figure 49: Economics for commercial solar and solar-plus-storage installed in France, 2021



Source: BloombergNEF. Note: 20kW PV and 10kW/20kWh battery systems, office load consuming 40,000kWh/year. Flat retail rate: EUR 0.10/kWh ($0.12/kWh). TOU: Variable peak: 6AM-10PM EUR 0.11/kWh ($0.13/kWh), Off-peak: 10PM-6AM EUR 0.08/kWh ($0.09/kWh). Assumes compensation under self-consumption scheme. Additional assumptions in Appendix A.

In the commercial segment, IRRs are lower than in the residential segment, at about 9% and 10% (or 10 and 9-year paybacks) in the flat and TOU tariff scenarios, respectively, compared to about 17% and 19% in the residential segment (6 and 5-year paybacks). This is because commercial systems receive lower compensation for exported electricity and lower 'self-consumption premium'. Additionally, residential power prices tend to be higher, heightening the savings potential for residential consumers.

Vehicle and heat electrification will increase loads and allow for larger solar system sizes. If loads are shifted to solar hours, self-consumption and therefore returns will also increase.

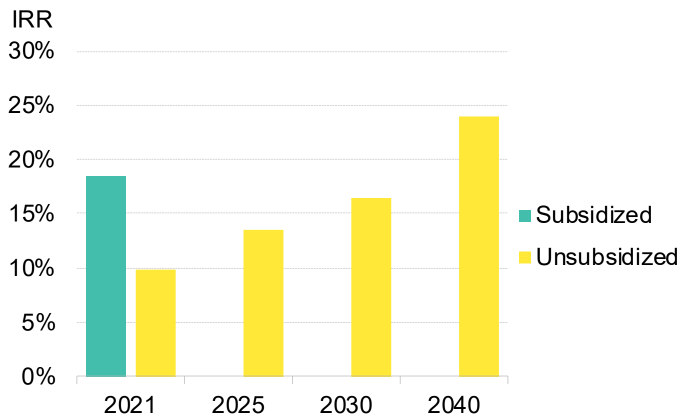
[16] We assume exported electricity is compensated at the wholesale electricity price.

However, government subsidies for solar may not be needed for long

Removing subsidies would worsen the economics of new solar installations in the short term, particularly for households that currently benefit from higher support. However, unsubsidized solar will likely become attractive to businesses and households by 2025 (Figure 50 and Figure 51). French power prices are expected to rise by 2025, due to a few factors including growing capacity mechanism payments, the potentially increasing cost of energy savings programs financed by the utility, and growing grid costs due to the connection of more renewable generation. This, coupled with declining solar costs, means that solar could be attractive even with lower compensation rates, for example, if solar was compensated at wholesale power prices.

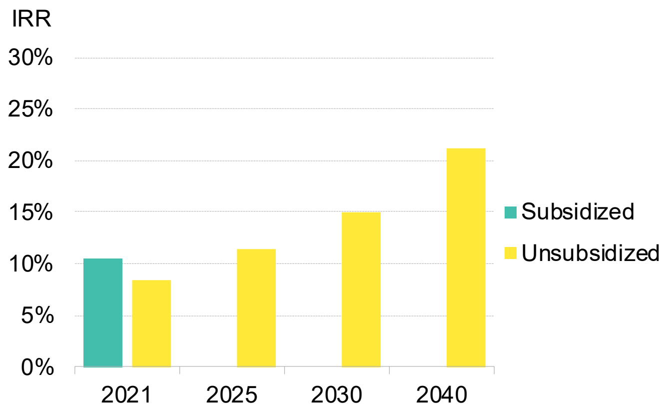
BloombergNEF estimates that by 2025, solar projects for the commercial segment would have similar returns to a subsidized project today (about 11% IRR). This happens slightly later in the residential segment (after 2030), but by 2025 returns are already attractive at 14%. Here, we assumed that customers would opt for TOU tariffs, which are currently structured with peak rates during solar hours and improve returns for solar customers compared to flat rates. The key conclusion is that government support may no longer be needed to support project economics by the late 2020s.

Figure 50: Forecast IRRs for unsubsidized residential solar in France



Source: BloombergNEF. Note: Subsidized = compensation for exports and 'self-consumption premium' under self-consumption scheme. Unsubsidized = exports compensated at wholesale price; both scenarios assume TOU tariffs.

Figure 51: Forecast IRRs for unsubsidized commercial solar in France



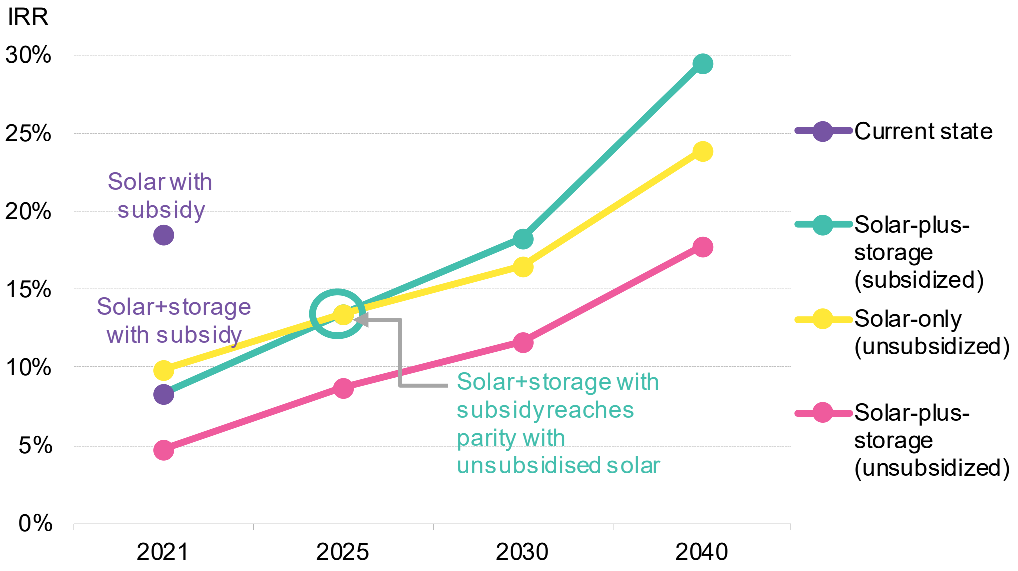
Source: BloombergNEF. Note: Subsidized = compensation for exports and 'self-consumption premium' under self-consumption scheme. Subsidized = exports compensated at wholesale price; both scenarios assume TOU tariffs.

Tying subsidy to residential storage rather than stand-alone solar could foster storage market development

If the value of premium export payments and the 'self-consumption premium' were only available to PV systems coupled with storage, these systems could reach economic parity with unsubsidized stand-alone solar by 2025, at about a 7-year payback (or 14% IRR, Figure 52). This could be a way for France to shift incentives to a newer technology. Flexible loads, such as electric water heaters with tank capacity, could also help absorb daytime generation and integrate higher penetrations of customer-sited solar, which could increase the IRRs for solar-plus-storage given their low- or zero-marginal cost.

Come 2040, subsidized residential solar-plus-storage could yield a 4-year payback, equivalent to IRRs of almost 30%, and be more attractive than solar alone. Of course, subsidies as they are today are likely to change by then, but this helps to give a sense of magnitute of its impact. Storage costs are projected to drop by over 50% from current rates by 2040, while PV capex will likely decline by about 40%. This, coupled with increasing power prices, would otherwise make storage-integrated systems more affordable for household consumers.

Figure 52: Internal rates of return for residential solar and solar-plus-storage systems in France, by year of commissioning



Source: BloombergNEF Note: Subsidized = compensation for exports and 'self-consumption premium'. Unsubsidized = exports compensated at wholesale price; both scenarios assume TOU tariffs.

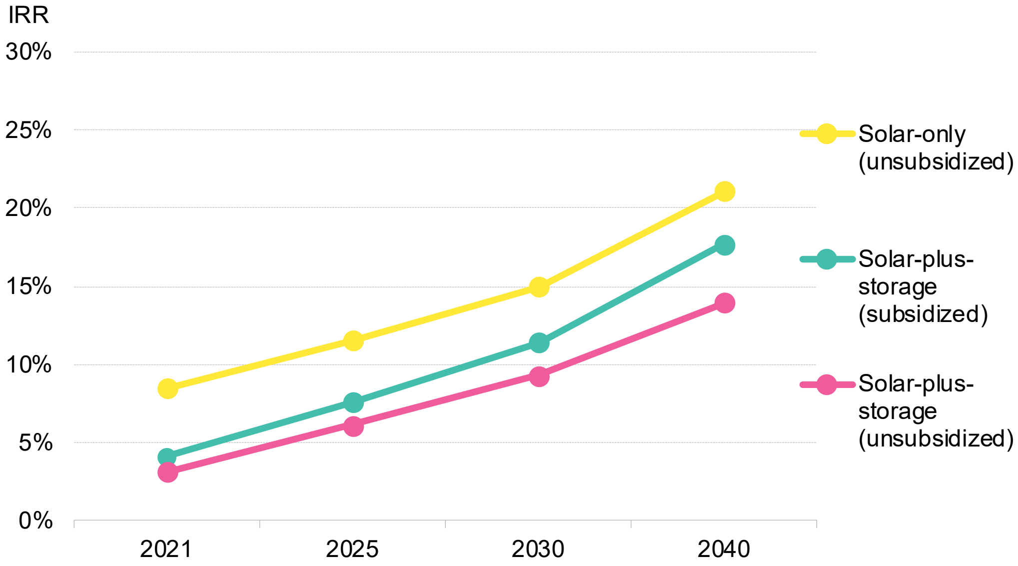
Commercial storage will likely require further intervention to make economics work

Solar-plus-storage is less attractive for businesses than for households. Businesses usually use the most electricity during the day, when PV is generating, making storage less useful for increasing the amount of solar that is consumed on-site. Additionally, power prices, compensation for exported electricity, and PV 'self-consumption premium' tend to be lower compared to residential.

The returns on commercial solar-plus-storage are lower than for solar by itself. This is because the economics generally worsen with the additional cost of pairing batteries with solar to increase the proportion of generated electricity consumed. As storage costs decline, the returns improve but the marginal benefit of storage to the solar system is low will not justify the cost.

Commercial solar-plus-storage will remain less attractive than solar by itself, even if the value of premium export payments and 'self-consumption premium' were only provided to PV systems coupled with storage (see Figure 53). BloombergNEF estimates that by 2025, IRRs for subsidized commercial solar and storage systems will be about 8%, with an 11-year payback (compared to near 12%, or 9-year payback, for unsubsidized solar alone). This is because commercial retail rates are low and load profiles well-aligned with solar.

Figure 53: Internal rates of return for commercial solar and solar-plus-storage systems in France, by year of commissioning



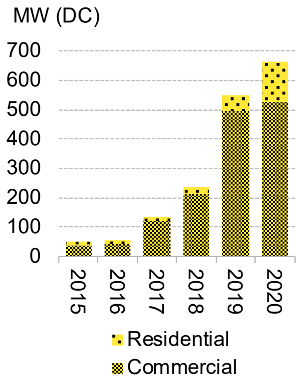
Source: BloombergNEF. Note: With subsidy = compensation for exports and capex support. Without subsidy = exports compensated at wholesale price; both scenarios assume TOU tariffs.

Additional revenue streams for commercial storage will likely be required to make the economics work. Avoided demand charges, for example, could improve the economics of adding storage. Currently, consumers subscribe to a power plan, which is based on their peak demand. The plan has two cost components: the yearly subscription price, which is higher for consumers with higher peak demand, and the electricity tariff, which is charged for every kWh consumed and varies depending on the time of day. Under this tariff design, business customers could potentially reduce their retail bills by using batteries to reduce peak demand (or, at lower cost, with shiftable load such as electric water tanks and electric vehicles), a factor we have not included in our modelling. The bill reduction might be easier to achieve if monthly demand charges were implemented, allowing a direct cost saving each month the customer is able to reduce its peak demand.

3.3. Spain

Customer-sited solar in Spain is already growing largely unsubsidized

Figure 54: Customer-sited solar capacity additions in Spain



Source: BloombergNEF

Spain's small-scale solar market boomed in 2019 following the removal of Spain's 'sun tax'[17] on self-consumption, and the simplification of connection and permitting processes for both households and businesses (Figure 54). The commercial segment in particular benefited from the removal of the sun tax on generated power for systems over 10kW. Systems installed on industrial and agricultural facilities are the main driver of this segment today. Solar customers can now also benefit from collective consumption in commercial settings like shopping centers, where businesses share roof space. Several consumers can share the generation from one system, allowing higher self-consumption rates in shared buildings and greater realized savings overall.

Additionally, as of the 2019 Royal Decree, solar customers in Spain can receive compensation for exported electricity, an option only previously available to legally authorized energy producers. Small-scale solar owners can choose one of three options for grid connection and compensation:

- **Systems smaller than 100kW:** customers can export electricity to the grid, and electricity retailers compensate them for exports either at the time-specific wholesale rate[18] or at a flat price agreed with the retailer in advance.
- **Systems larger than 100kW (market export):** can become an energy producer and export to the market. This will come with extra grid connection requirements and costs.
- **Self-consumption:** customers are not allowed to export power and can avoid the added grid connection requirements.

In Spain, solar is currently unsubsidized and is economic without subsidy, due to high power prices and abundant sunshine. We estimate that solar yields 17% and 19% IRRs for residential and commercial customers (equivalent to 7 and 6 year paybacks) respectively, assuming that they are on time-of-use (TOU) tariffs which are now compulsory (see Figure 55 and Figure 56).[19]

Commercial solar returns are higher than residential because load profiles tend to line up better with solar generation and commercial systems tend to be sized to maximize self-consumption to avoid exports to the grid. Solar used to offset retail costs is more valuable than solar exported for a sub-retail export payment. Households face fewer grid-connection hurdles and are more likely to export to the grid. For both sectors, electrification of vehicles and heat may increase loads, allowing for larger solar system sizes. If loads are shifted to solar hours, self-consumption will also increase and the self-consumption option would become more attractive.

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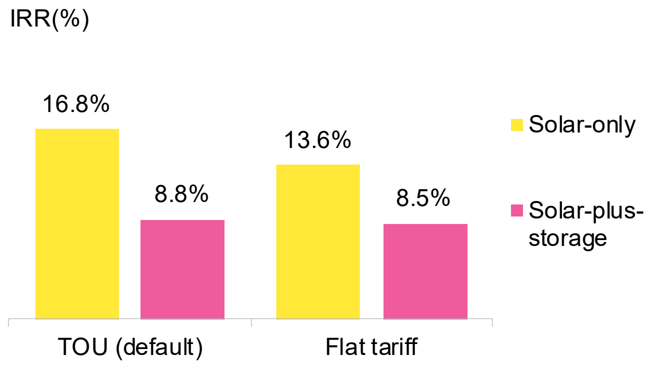
[17] The sun tax was a set of charges on self-consumption, to cover distribution and maintenance costs in the grid. The level varied, but it was about 4-6 eurocents per kWh for systems over 10kW, and the consumer received no credit for exported power.

[18] Under this option, exports are metered, but the energy bill is not necessarily reduced on a 1-to-1 basis. Rather, a price is set by the retailer for the exported electricity, dependent upon the electricity price at the time of export. Compensation for exports never exceeds the size of the monthly power bill.

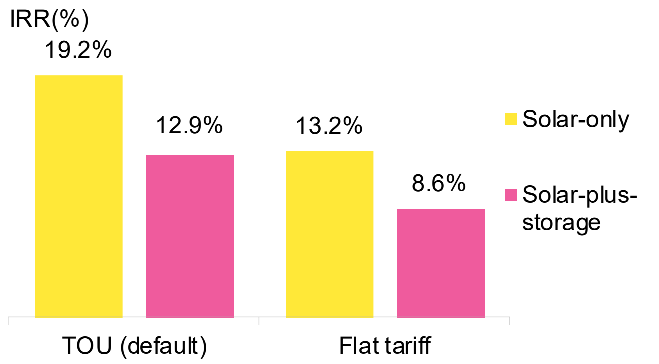
[19] As of June 2021, residential consumers have been required to transition to a new standardized tariff structure (called 2.0TD) set by the regulator, which includes three different rates (peak, off-peak, and super off-peak) over the course of weekdays, and a flat super off-peak tariff on weekends. The new tariff design is meant to encourage consumers to shift their demand. This structure is now required for all small-scale consumers. Commercial consumers with power demand exceeding 15kW are on tariffs which follow a 6-period schedule, with monthly and day-of the week variation. Off-peak rates are charged early in the morning, in the afternoon, and throughout the weekend, and peak periods coincide with mid-morning and evenings, and are especially high during the winter and mid-summer months. In parallel, utilities offer solar rates for customers who want to install PV.

Figure 55: Economics for residential solar and solar-plus-storage installed in Spain, 2021



Source: BloombergNEF. Note: 4.3kW PV and 7.2kWh battery systems, 4,046kWh/year home. Flat tariff = EUR 0.22/kWh. TOU: assumes customer is enrolled in a solar plan (EUR 33c/kWh during solar hours, ranging from 9AM-6PM throughout year, and EUR 15c/kWh for all other hours, see Figure 57. Exports compensated at approximately wholesale rate. See full assumptions in the Appendix A.

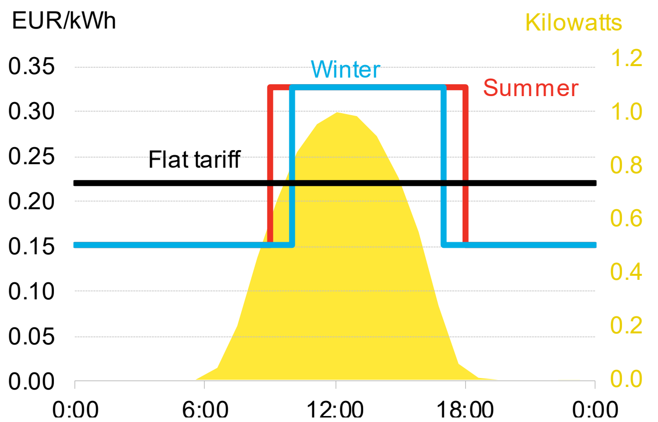
Figure 56: Economics for commercial solar and solar-plus-storage installed in Spain, 2021



Source: BloombergNEF. Note: 50kW PV and 10kW/20kWh battery systems, 40,000kWh/year office load. Flat tariff = EUR 0.18/kWh. TOU: assumes customer is enrolled in a solar plan (EUR 25c/kWh during solar hours, ranging from 9AM-6PM throughout year, and EUR 17c/kWh for all other hours, see Figure 58). EUR 5c/kWh export payment. See full assumptions in the Appendix A.

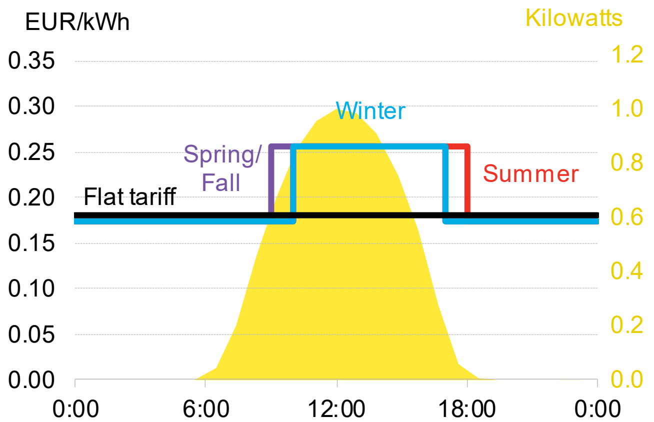
Spain's TOU tariffs[20] result in higher returns for residential and commercial customers than if customers were on flat rates, mainly because the TOU rates are higher than the flat tariff during solar hours. TOU is more impactful in improving solar economics in the commercial segment, where load aligns more with solar generation times. In addition, the residential TOU off-peak rate is lower than the flat tariff, which means solar generated during those hours saves the customer less compared to the flat tariff.

Figure 57: Spain sample residential TOU (default) rate



Source: BloombergNEF. Note: solar generation (in yellow) is exemplary only, generation profile will differ by season. Sample for small utility in Spain, further details in Appendix A.

Figure 58: Spain sample commercial TOU (default) rate



Source: BloombergNEF. Note: solar generation (in yellow) is exemplary only, generation profile will differ by season. Sample of Iberdrola's Solar Plan rate in Aug 2021, details in Appendix A.

20 Retail rates are generally sample rates used to exemplify economics in the country/region but in reality may vary significantly across utilities within a country, as well as by type of and size of load (small commercial, industrial and agricultural loads often have different rates).

Energy storage in Spain would likely need support

At present, solar-plus-storage is less attractive than stand-alone solar in Spain (Figure 55 and Figure 56). We estimate that under the TOU tariff structure, households can expect paybacks of 7 years with IRRs of about 17% for solar alone, while systems coupled with storage would yield IRRs of only 9% and a 10-year payback. In the commercial segment, TOU consumers with solar and solar-plus-storage can expect IRRs of about 19% and 13% respectively, or 6- and 8-years payback. The storage-paired option is more attractive on the commercial segment, although still less attractive than a solar-only proposition.

Storage is hampered by high capex, and in the commercial segment, by the fact that load profiles tend to coincide well with times of peak solar generation. Going forward, large capex declines coupled with some form of subsidy will likely be required to make small-scale solar with storage feasible. Demand charges could improve the outlook for commercial storage. Businesses already face power plans with an added peak demand charge, in addition to the per kWh tariff.[21] Businesses could potentially use batteries to reduce this portion of their electricity bill, although we have not modelled this in our analysis. Demand charges which could more easily be reduced using batteries would improve the case for businesses to add storage.

Future uptake depends on the power price outlook

As renewable energy penetration grows in Spain and more costly fossil fuel power assets are retired, BloombergNEF analysis suggests wholesale power prices may decline (Figure 59).[22] Under a least-cost economic transition scenario (ETS), wholesale power prices could drop by nearly 60% between 2021 and 2025. Power prices recover again after 2025, as gas and carbon prices increase, electricity demand grows with electric vehicles deployment and renewable capacity development lags fossil fuel generator retirement. New renewable capacity may be developed as demand increases, rather than replacing fossil fuel assets, allowing wholesale price recovery through the last half of the current decade.[23]

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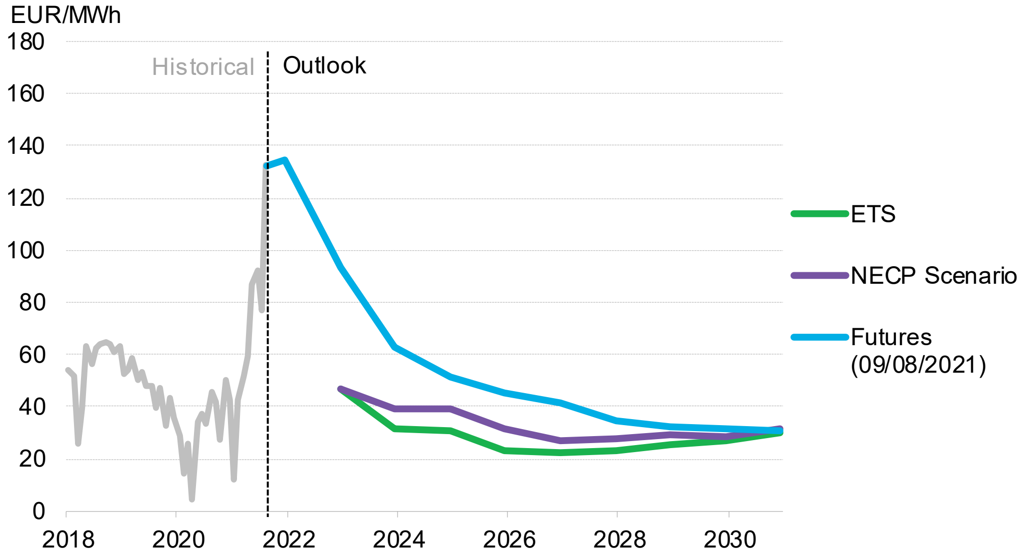
21 Known as "power term", it is charged on a per kW basis based on peak demand; it is a sort of subscribed peak power that consumers pay for, and it varies with the time of day, day of the week, and season, similarly to the per kWh tariff.

22 Note that this is the opposite to France, where prices are expected to rise by 2025, as costly nuclear assets need to be maintained and refurbished.

23 Note that this represents BloombergNEF's view on trajectory of power prices. There is, however, uncertainty with regards to how this will indeed unfold given annual volatility, EU carbon pricing fluctuation and other factors. For more on BloombergNEF's take see *2021 Spain Power Market Outlook* (web | terminal)

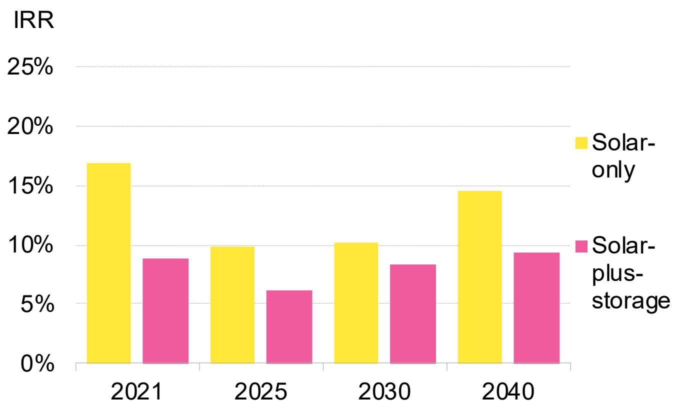
Figure 59: Spanish power prices outlook



Source: BloombergNEF Note: ETS = Economic Transition Scenario (BloombergNEF least-cost power market scenario without policy intervention); NECP Scenario follows Spain's National Energy and Climate Plan 2030 capacity targets for wind and solar; Futures curve is from the OMIP exchange on September 8, 2021.

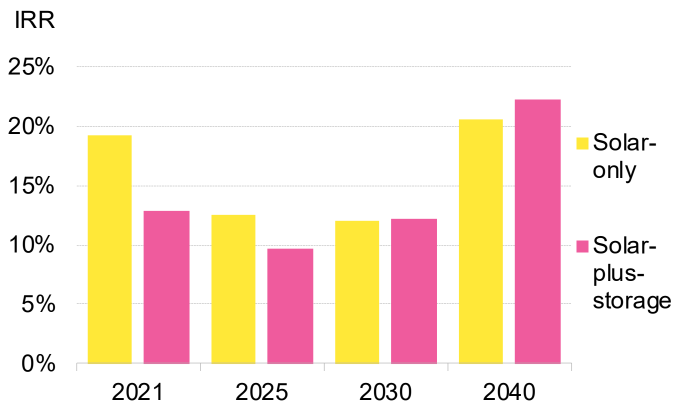
Wholesale power price declines have knock-on effects for customer-sited solar and storage if retail rates fall and reduce the associated potential energy bill savings. If retail rates remain correlated with wholesale rates to the same degree as they have in the past, the economics of small-scale solar and storage could become less attractive in the near term (Figure 60 and Figure 61). We estimate that by 2025, IRRs for residential and commercial solar would fall to about 10% and 13% (paybacks of 10 and 9 years), respectively.

Figure 60: IRRs for residential solar and solar-plus-storage installed in Spain, changing retail rates



Source: BloombergNEF. Note: assumes declining retail rates to reflect overall wholesale energy price drops.

Figure 61: IRRs for commercial solar and solar-plus-storage installed in Spain, changing retail rates



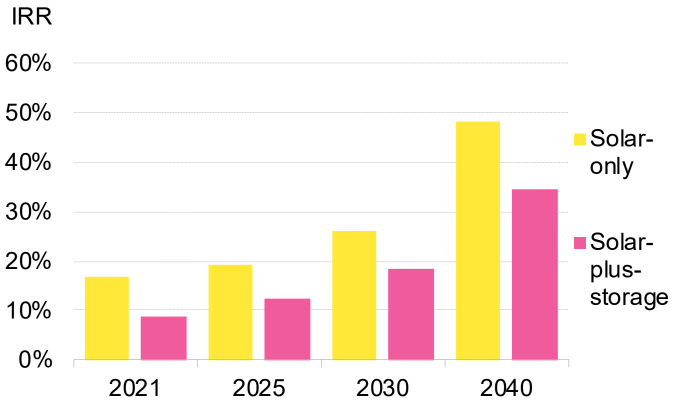
Source: BloombergNEF. Note: assumes declining retail rates (a 60% drop in the energy portion of the rate, which accounts to about 30% of the retail tariff. Also assumes a higher price drop during solar hours).

Plummeting power prices could drive this worsening economics near-term, but economics would recover by 2030 in the residential sector, and between 2030 and 2040 for commercial buildings as capex declines and higher retail rates improve the economics (excluding any additional revenues from grid services). Note that economics for commercial solar would still be quite attractive and that the relative economics for batteries in the 2030s begin to look better in particular as we assumed that retail rates would decline during solar hours, providing an incentive to add batteries.

The impact of wholesale rate declines on retail rates could be limited since a large component of retail rates in Spain are the taxes and levies charged to consumers. If retail rates remained constant over time, the economics of residential and commercial solar and storage would improve steadily (Figure 62 and Figure 63). In 2025, residential and commercial solar would yield IRRs of about 19% and 23% respectively (paybacks of 6 and 5 years), significantly more attractive than the 10% and 13% achieved if retail rates fall.

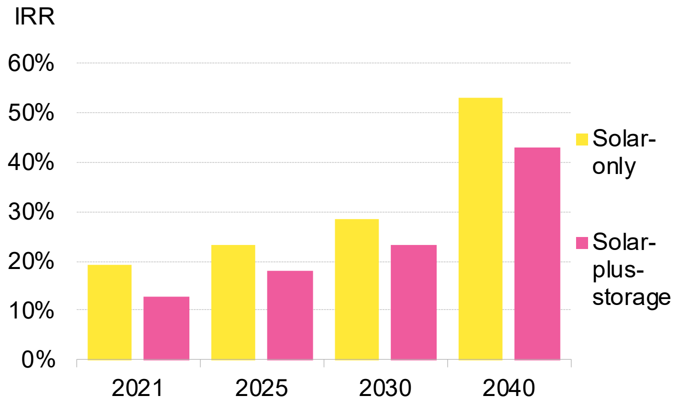
The economics of solar-plus-storage would also improve but would still be slow to become attractive in the residential sector due to high storage capex, and never quite surpasses solar economics without a time-reflective retail rate that discounts retail prices during solar hours more heavily. It is also worth noting that rising solar penetrations would likely lead to a re-design of TOU tariffs to favor evening generation, and therefore improve the economics of storage paired with solar. This is discussed in the following sections.

Figure 62: IRRs for residential solar and solar-plus-storage installed in Spain with retail rates constant over time



Source: BloombergNEF

Figure 63: IRRs for commercial solar and solar-plus-storage installed in Spain, with retail rates constant over time



Source: BloombergNEF

If power prices continue to fall, and are passed onto consumers, policy intervention might be needed to mitigate the impact of lower energy prices on solar economics in Spain. Such support could then be tapered off as capex costs fall and power prices start to recover. The need for support will depend on the power price outlook. Storage would likely need additional support to encourage deployment, particularly in the residential sector where costs are higher. Incorporating demand charges and encouraging demand-shifting behavior could improve the economics for both commercial and residential consumers until batteries are cheap enough to make solar and storage economical.

Solar in Spain is already growing largely unsubsidized, after the removal of a sun tax and onerous permitting processes. Further solar cost declines should improve economics but could retail price declines could undermine unsubsidized solar returns. Battery storage will likely need support in the near term to foster market development. Demand charges could improve the outlook for commercial storage.

A note on declining wholesale power prices and the role of policy

The above analysis shows a decline in wholesale power prices in Spain as renewable penetrations rise. This downward pressure on prices can come about in any given market as a result of both utility-scale renewable energy build and customer-sited renewables adoption. In principle, both utility-scale and customer-sited installations face some risk from this deflationary effect, since their value is linked to power prices. For this reason, the 'right' policy environment to deliver on a high-renewables power system needs to make ensure that there are still stable, long-term returns available to investors in both utility-scale and small-scale renewable energy.

3.4. New Jersey

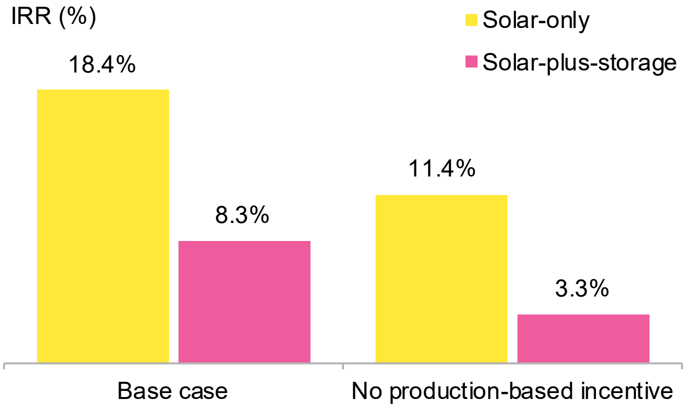
Generous production-based incentives have helped to support growth

Production-based incentives that pay solar projects for each MWh produced have supported the New Jersey customer-sited solar market, which has reached 2.7GW as of March 2021. These subsidies have been instrumental for new solar built in New Jersey for over a decade. The amounts paid have varied over time. The incentive was over $200/MWh before regulators reduced it to $91/MWh for residential and $152/MWh for commercial solar in 2020. In addition to this subsidy, residential and commercial solar project owners have access to retail rate net metering, which credits exported solar generation to customers' bills at their retail rate.

As of July 2021, the New Jersey Board of Public Utilities (BPU) has been assessing a revision to the production-based incentive. The proposal entails paying new residential and commercial solar projects $85/MWh of solar produced over 15 years. The NJ BPU would review the incentive level every three years, to align with continued solar cost reductions.

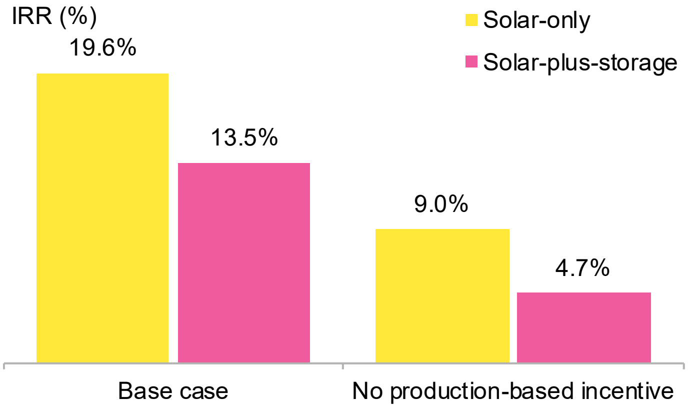
The economics for customer-sited solar and solar-plus-storage materially deteriorates without the incentive, even if net metering continues (Figure 64 and Figure 65). For residential solar, IRRs would drop by seven percentage points, to 11.4%, or a 9-year payback, which would barely exceed the 10-12% return threshold, or 8-year payback, that households typically use to consider a capital investment. Far fewer homeowners would go forward with customer-sited solar at this point, and no customer would have an economic incentive to add storage. Comparably, commercial solar would have a more significant drop, down 10.6 percentage points, to a 9.0% IRR or 10-year payback period. Few commercial and industrial customers would have an economic motivation to add customer-sited solar at 9.0% IRR and would more likely instead choose to spend the money in their core businesses.

Figure 64: Impact on returns of removing production-based incentive for New Jersey residential solar, and solar-plus-storage



Source: BloombergNEF. Note: 7kW PV and 14kWh battery systems, 8,000kWh/year home. Federal ITC assumed. Retail rate = $0.17/kWh. Export = 100% retail rate. Additional assumptions in Appendix A.

Figure 65: Impact on returns of removing production-based incentive for New Jersey C&I solar, and solar-plus-storage



Source: BloombergNEF. Note: 100kW PV and 50kW/100kWh battery systems, 114,000kWh office load. Federal ITC assumed. Retail rate = $0.08/kWh, demand charge = $19/kW/month. Additional assumptions in Appendix A.

Reducing export rates nudges commercial and industrial customers towards solar-plus-storage

Here we explore a scenario where, instead of removing production-based incentives, regulators reduce export rates instead. Export rates are currently set at the retail rate, as mentioned above. In this analysis, we reduce them to 35% of the retail rate.

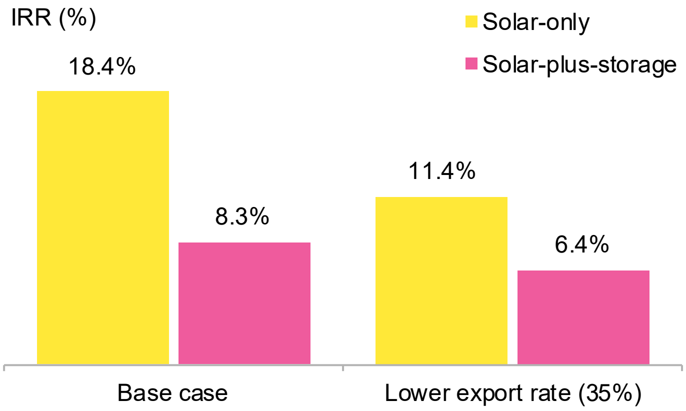
Commercial and industrial customer-sited solar projects in New Jersey typically export less of their generation than residential. In our modelled commercial case, for example, around 60% of the solar generated was consumed, compared to about 35% in the residential sector. This is largely due to commercial loads coinciding more with solar generation than residential loads (in general). These higher consumption rates make the economics of commercial solar less dependent on the export payments. This means returns for C&I solar-only under lower net metering rates are still attractive, at 16.2% IRR or 5-year payback period (Figure 66).

Adding batteries helps commercial customers use as much as 77% of the solar produced. Because self-consumption rates with batteries are high, returns for solar-plus-storage drops by only 1.4 percentage points under lower net metering rates, while solar-only returns worsen by 3.4 percentage points.

For residential solar, reducing the payment for solar exports has a similar IRR impact as removing the production-based incentive – they reduce IRRs to 11.4%, equivalent to an 8-year payback period (Figure 67). However, home solar-plus-storage yields higher returns in a lower export payment than in a scenario without a production-based incentive, although a 6.4% IRR (11-year payback) would still be unlikely to drive adoption.

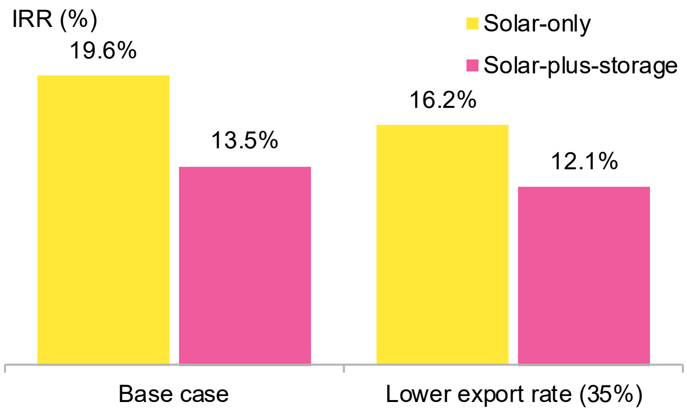
It is unlikely that regulators will keep the production-based incentives at current levels and choose instead to lower solar export payments to 35%, as we have modelled here. If regulators think subsidies for solar in their state are too aggressive, they would most likely remove the production-based incentives before lowering net metering. We expect regulators to reduce solar export payments in New Jersey once solar penetration reaches levels seen in California or Hawaii.

Figure 66: Returns for New Jersey residential solar, and solar-plus-storage with high and low export rates



Source: BloombergNEF. Note: 7kW PV and 14kWh battery systems, 8,000kWh/year home. Federal ITC assumed. Retail rate = $0.17/kWh. Base-case export rate = 100% retail rate. Additional assumptions in Appendix A.

Figure 67: Returns for New Jersey C&I solar, and solar-plus-storage with high and low export rates



Source: BloombergNEF. Note: 100kW PV and 50kW/100kWh battery systems, 114,000kWh office load. Federal ITC assumed. Retail rate = $0.08/kWh, demand charge = $19/kW/month. Base-case export rate = 100% retail rate. Additional assumptions in Appendix A.

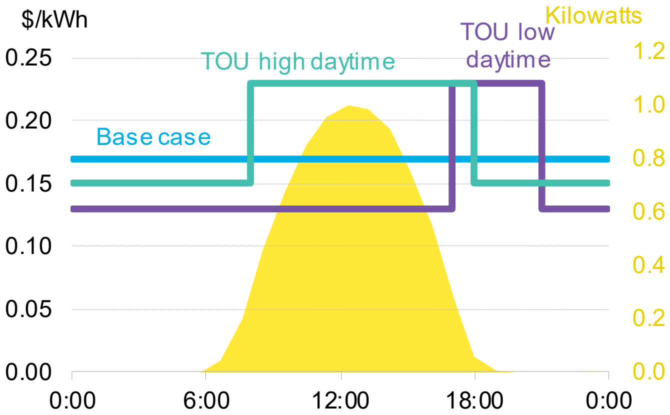
Time-of-use (TOU) pricing is a powerful tool to change customer-sited solar economics and incentivize more battery attachment

Instead of changing export payment rates, New Jersey utilities and regulators could use time-of-use pricing signals to discourage or incentivize more customer-sited solar and storage. While lower export rates only change the compensation for the excess solar produced, lower daytime rates (and comparatively higher evening rates) can also encourage users to shift their solar production using energy storage. New Jersey residential, commercial and industrial customers typically pay a flat rate or a consumption-tiered rate[24] for their variable electricity costs.

Generally, regulators and utilities use time-of-use structures with lower daytime rates to reflect the lower generation costs during solar hours (relative to higher generation costs during peak evening hours when thermal generators need to ramp up). This can encourage more energy consumption during the daytime and may incentivize customer-sited solar customers to add a battery. It may also incentivize customers to shift loads to the daytime to absorb solar generation. Vehicle and heat electrification could increase load size and flexibility.

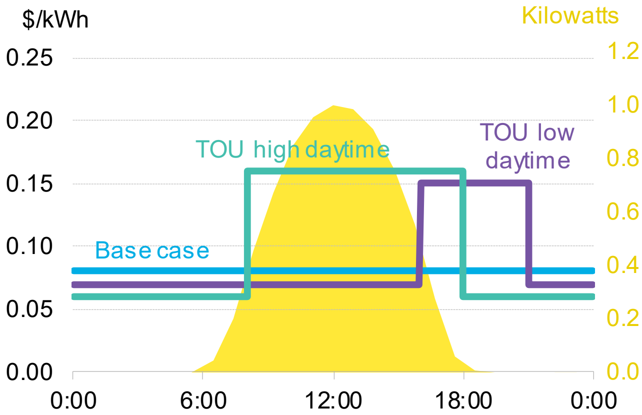
[24] Consumption-tiered rate is a flat rate for brackets of energy consumption (e.g. first 100kWh at $0.16/kWh and any additional consumption at $0.25/kWh).

Figure 68: New Jersey assumed time-of-use rates for residential customers with solar generation



Source: BloombergNEF. Note: solar generation (in yellow) is exemplary only, generation profile will differ by season.

Figure 69: New Jersey assumed time-of-use rates for C&I customers with solar generation

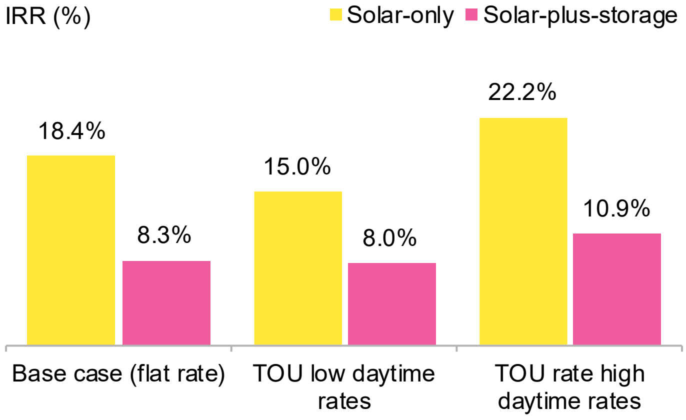


Source: BloombergNEF. Note: solar generation (in yellow) is exemplary only, generation profile will differ by season. Analysis included $19/kW/month demand charge in addition to variable time-of-use rate.

Under an assumed scenario with low daytime TOU rates for New Jersey, we modelled 40-60% lower daytime rates during 8AM-4PM compared with peak prices between 4PM-9PM, which resembles the current rate structures in California. Economic returns in New Jersey for solar-plus-storage stay the same under low daytime TOU rates compared with a flat rate structure (Figure 72). This is because customers can store the solar generated during the day and use it during the higher price windows in the evening. Commercial customers can also use the battery to reduce their peak demand charges, which is accounted for in the base case and sensitivities below (Figure 71).

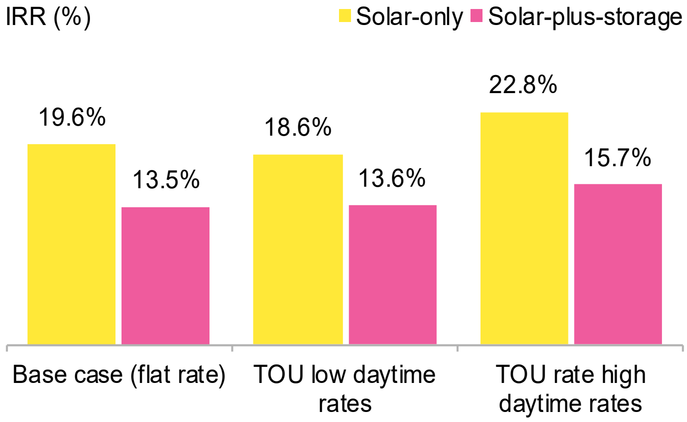
In an opposite design, where daytime rates are higher, we assumed 42% lower evening rates for commercial during 6PM-9PM, and peak prices at about $0.14/kWh from 8AM-6PM. For residential, we assumed 46% lower rates between 4PM-9PM and peak prices at $0.23/kWh from 8AM-4PM. Returns for both solar and solar-plus-storage improve, as peak solar production times overlap with the highest prices (Figure 70, Figure 71). This could be a mechanism to encourage more customer-sited solar. Returns for residential solar-only systems, however, are so much higher than for solar-plus-storage that customers would have no economic incentive to add a battery. In such a rate structure, there is little value to storing and using the solar electricity at night. For commercial systems, batteries can still help offset demand charges.

Figure 70: Returns for New Jersey residential solar under different time-of-use structures



Source: BloombergNEF. Note: 7kW PV and 14kWh battery systems, 8,000kWh/year home. Federal ITC assumed. Rate assumptions in Figure 68. Base-case export rate = 100% retail rate. Base case refers to the flat rate structure. Additional assumptions in Appendix A.

Figure 71: Returns for New Jersey C&I solar under different time-of-use structures



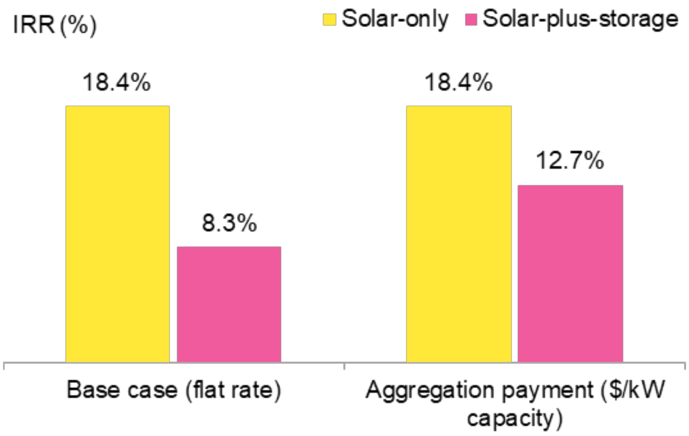
Source: BloombergNEF. Note: 100kW PV and 50kW/100kWh battery systems, 114,000kWh office load. Federal ITC assumed. Variable rate assumptions in Figure 69, demand charge = $19/kW/month. Base-case export rate = 100% retail rate. Additional assumptions in Appendix A.

Payments for grid services can sweeten the deal for storage

Some utilities and aggregators in the U.S. pay or reward customers to participate in virtual power plants where they can call upon customer batteries when needed. The additional payments improve the economics for solar-plus-storage and make batteries more appealing to both residential and commercial customers.

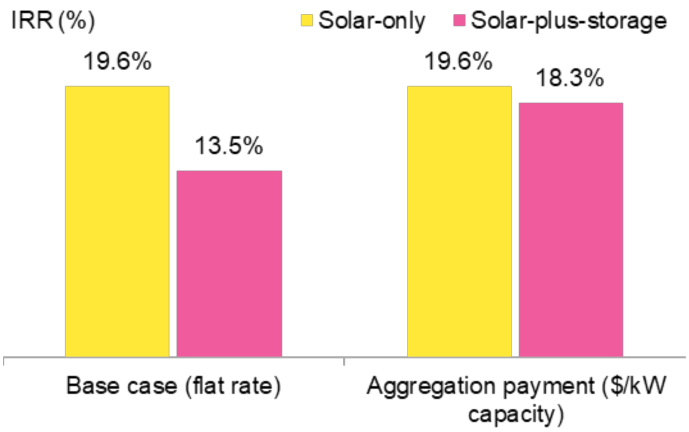
Returns for solar-plus-storage improve and get closer to solar-only if solar and storage customers in New Jersey receive a $/kW/year payment to participate in such an aggregation program (below, we assumed $100/kW/year in line with some existing programs in the U.S. although there would likely be uncertainty on the longevity and amount of these payments for any given site). For residential, IRRs for solar and storage improve to 12.7% from 8.3% and the payback period falls to 8 years. For C&I, solar and storage IRRs improve to 18.3% from 13.5%, and the payback period falls to 5 years from 6.

Figure 72: Returns for New Jersey residential solar with and without aggregation payments for batteries



Source: BloombergNEF. Note: 7kW PV and 14kWh battery systems, 8,000kWh/year home. Federal ITC assumed. Retail rate = $0.17/kWh. Base-case export rate = 100% retail rate. Base case refers to the flat rate structure. $100/kW capacity/year assumed for residential solar and storage aggregation payments. Additional assumptions in Appendix A.

Figure 73: Returns for New Jersey C&I solar with and without aggregation payments for batteries



Source: BloombergNEF. Note: 100kW PV and 50kW/100kWh battery systems, 114,000kWh office load. Federal ITC assumed. Retail rate = $0.08/kWh, demand charge = $19/kW/month. Base-case export rate = 100% retail rate. $100/kW capacity/year assumed for commercial solar and storage aggregation payments. Additional assumptions in Appendix A.

Streamlined permitting and interconnection could offset negative effects from lower export rates

As outlined above, lower export rates would deteriorate the economics for both solar and solar-plus-storage in New Jersey. Many utilities across the U.S. advocate for lower net metering rates because they claim this policy shifts costs to non-solar customers. BloombergNEF expects the net metering rates to decrease as some places reach high solar penetration levels. Power markets that have a lot of solar see depressed daytime power prices that can even reach negative levels, which reduces the value of each additional customer-sited solar kWh produced. At current solar penetration levels of 3% of total utility customers with customer-sited solar, it is unlikely that New Jersey drastically cuts export payments.

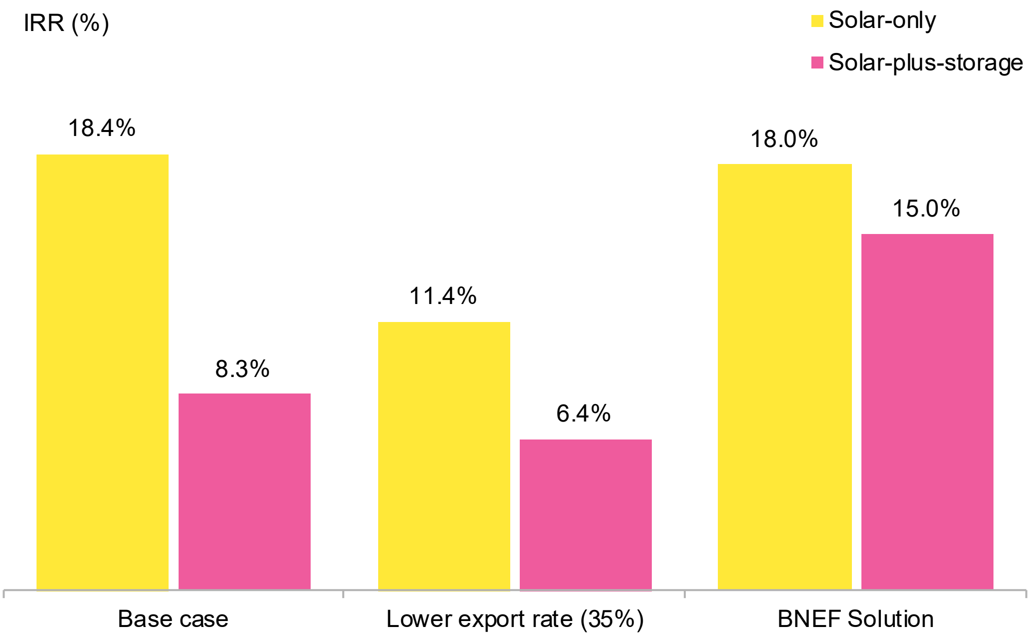
We modelled a scenario for residential solar that incorporates a set of policy tools and market incentives that are currently being discussed across several U.S. markets, including New Jersey. We have labelled this scenario as 'BNEF Solution' in our analysis. The objective was to test whether these new solutions could offset the lower revenues if regulators cut net metering to 35% of the retail rate. The policy and market solutions include automated permits and interconnection, aggregation payments, as well as incentives that create a higher pool of qualified labor force.

Permitting, interconnection and labor market incentives translate into lower upfront costs, while aggregation payments provide an additional revenue stream for batteries. We included the production-based incentive ($85/MWh) as part of the BNEF Solution given its recent extension and the subsidy's specific role in meeting the state's 2030 and 2050 climate targets.

These three incentives combined (permits, labor, aggregation payments) would materially improve the returns for residential solar-plus-storage in New Jersey, and result in more customer-sited solar paired with batteries (Figure 74). For solar-only systems, lower upfront costs offset cuts in net metering payments and keeps returns at 18% IRR or 6-year payback.

A bill that allowed the installation of residential solar systems in New Jersey prior to obtaining construction permit and interconnection passed the state Senate in 2020. While the bill has not become law yet, it signals policy makers' intentions to improve customer-sited solar installation processes.

Figure 74: Returns for New Jersey residential solar under lower export rates with different installation cost and aggregation payment scenarios



Source: BloombergNEF. Note: 7kW PV and 14kWh battery systems, 8,000kWh/year home. Federal ITC assumed. Base-case retail rate = $0.17/kWh, base-case export rate = 100% retail rate. BNEF Solution scenario assumes lower export rates at 35%, reduced installation costs from automated permitting and lower labor costs, production-based incentives remain, and aggregation payments for batteries of $100/kW capacity/year. Additional assumptions in Appendix A.

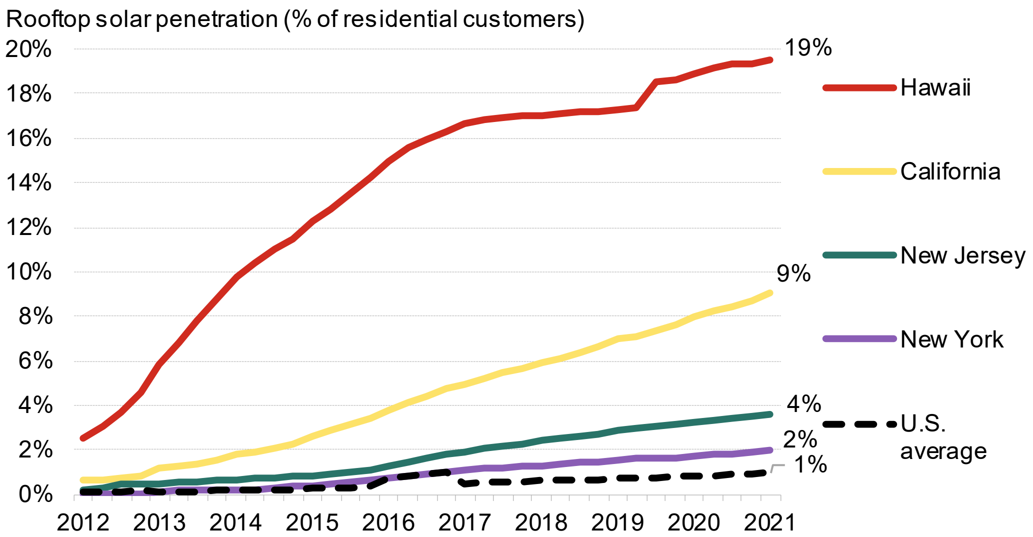
3.5. California

California is one of the most decentralized energy markets in the U.S.

California has one of the highest percentages of residential utility customers that have installed customer-sited solar in the U.S. (second only to Hawaii, Figure 75). Customer-sited solar penetration rates for California investor-owned utilities Pacific Gas and Electric, San Diego Gas and Electric and Southern California Edison were higher than the state average in 1Q 2021 at 26%, 16% and 10%, respectively. California has already transitioned to a fairer value payment for customer-sited PV exports and is moving toward a third stage of incentivizing customer-sited solar with batteries.

High utility rates, great solar resources and early incentives for customer-sited solar spurred market growth in California for distributed solar and will continue to drive market growth. Retail-rate net metering is the last incentive available for customer-sited solar, but we expect export payments to decrease as more solar projects come online. Batteries are also eligible for a generous upfront rebate in California as part of the self-generation incentive program (SGIP), which is geared to encouraging massive distributed energy storage alongside PV. This is helping at the distribution level of the grid to mitigate grid issues arising from deep penetration of PV.

Figure 75: Residential customer-sited solar penetration in the U.S.: top states and U.S. average



Source: BloombergNEF, EIA 861m

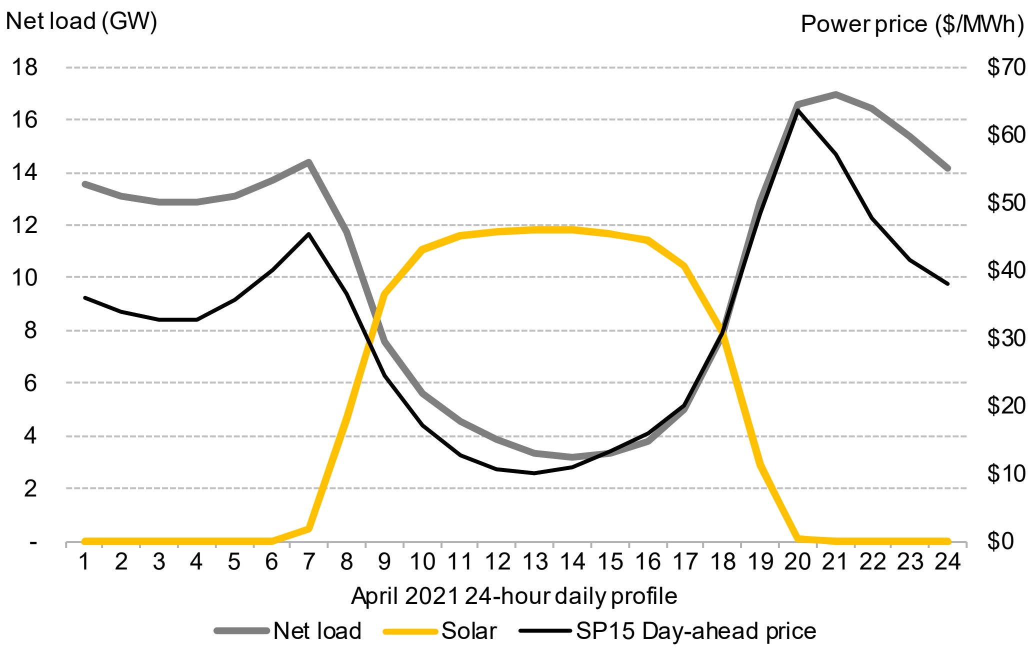
California solar policy requires reform to incentivize customer-sited solar with batteries

The key policy and regulatory challenge for customer-sited solar in California is how to use tariff structures and subsidies to incentivize most, if not all, customer-sited solar to come with a battery. Increased utility-scale and customer-sited solar penetration has depressed power prices in California during the day and reduced total net electricity demand (Figure 76). Other examples where solar has re-shaped power markets are Hawaii and Australia. With high solar penetration, peak 'net' electricity demand shifts to the evening and power prices are highest at this time. In California, system operators must quickly ramp up expensive natural gas plants to meet the evening demand once solar output drops.

Because of these sharp changes in the load profile, regulators and grid operators want more batteries paired with customer-sited solar. Batteries can store some of the daytime solar output so that customer can use the power during the most expensive evening times. This flexibility would allow customers to offset the highest power prices while helping system operators stabilize the grid.

An extreme example of encouraging only solar-plus-storage installations is Hawaii, where utilities only allow customer-sited solar systems that have a battery to export solar to the grid. In 2020, at least a quarter of new customer-sited solar systems in Hawaii had a battery.[25]

Figure 76: April 2021 California power market duck curve



Source: BloombergNEF

California regulators, utilities and solar advocates have all proposed changes to incentivize new customer-sited solar and storage. Regulators are contemplating a series of options to increase the share of distributed storage to the grid that aim to make solar-plus-storage more attractive than standalone solar. Some active regulatory and market proposals include:

1. Direct upfront rebates for batteries under the self-generation incentive program
2. Lower payments for solar exports
3. Lower daytime time-of-use rates
4. A combination of 2 and 3
5. Aggregation payments for batteries
6. Streamlined permitting and interconnection, standard mechanical and electrical codes
7. Solar charges

Utilities are advocating for lower export payments, a new time-of-use structure and solar charges

California has already updated how it compensates customer-sited solar exports once before. In 2017, utilities changed from a flat tariff structure to time-of-use rates with low daytime prices and high evening prices. This change meant that electricity offset by customer-sited solar, either

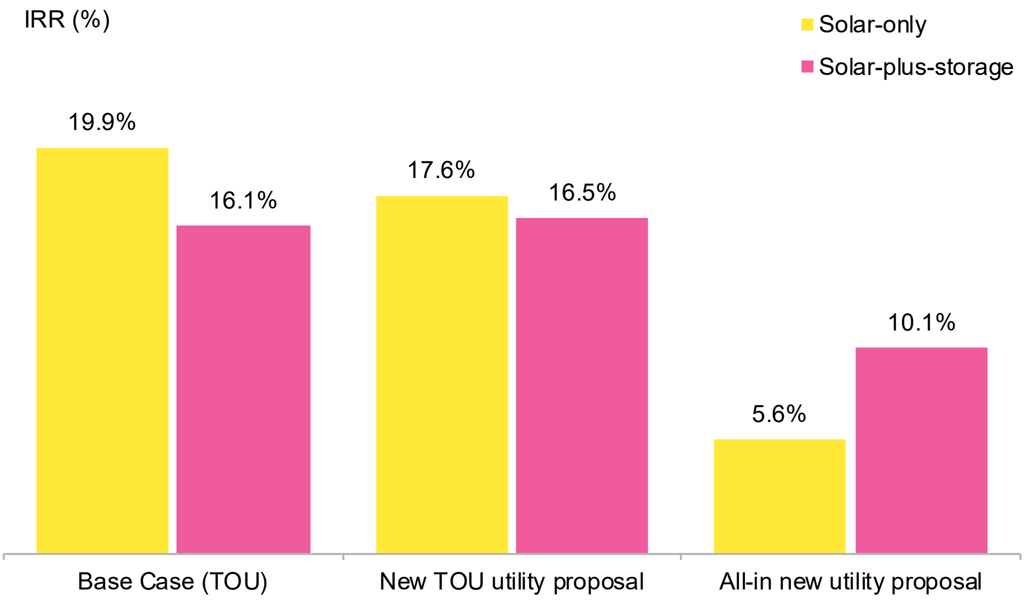
[25] This percentage considers the U.S. Energy Information Agency's data for solar and storage installations, which likely under-counts storage installations. Other sources such as the Lawrence Berkeley National Laboratory estimate that attachment rates are closer to 80%.

through self-consumption or export payments, was worth less due to low daytime rates. Solar exports still received the full value of the new (lower) daytime rate.

The regulator is expected to issue a final decision on the current net metering proceeding in late 2021. California utilities want to reduce payments for customer-sited solar exports to about 29-34% of the already lower daytime rate, depending on the utility. They have also proposed to adjust time-of-use rates and levy a monthly solar charge.

As an example, Southern California Edison has proposed to default all new solar customers to its PRIME rate, which charges peak prices of $0.41-0.44/kWh during 4PM-9PM and off-peak prices as low as $0.16/kWh, depending on the season. The proposed rate change would barely change returns for residential solar and storage (Figure 77). But returns drop significantly once we combine the new time-of-use rate with the suggested reduction in export payments and the solar charge. Under this scenario, internal rates of return (IRRs) for solar-only decrease from 19.9% to 5.6% (payback period rises from 6 to 15 years) and from 16.1% to 10.1% (payback period rises from 7 to 10 years) for solar-plus-storage. The new IRRs would provide no economic incentive for further home solar build in California for existing homes, and only customers interested in grid resilience would install panels with batteries. New residential buildings are required to add solar under a state mandate.

Figure 77: Return comparison with only changes in time-of-use rates vs all of the proposed changes (time-of-use, lower export rates and solar charge) for California residential solar



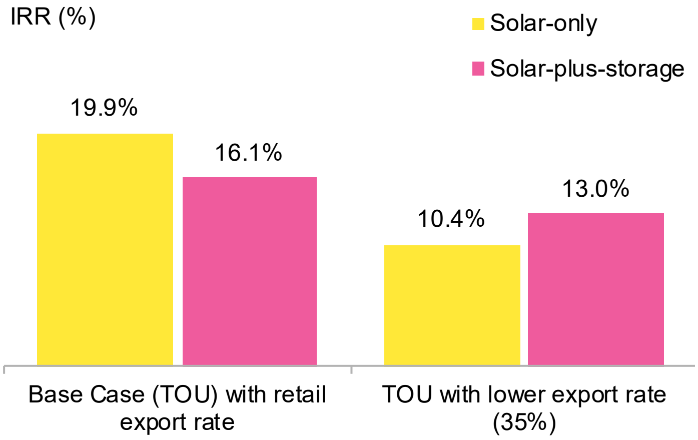
Source: BloombergNEF. Note: 8kW PV and 5kW/14kWh battery systems, 12,000kWh/year home. Federal tax credits, rebates for storage assumed. Base Case (TOU): Peak: 4-9PM $0.41/kWh, Off-peak: $0.17/kWh. New TOU utility proposal: Peak: 4-9PM, $0.44/kWh, Off-peak: 8PM-5PM, $0.16/kWh. All-in new utility proposal: adds 34% net metering; solar charge $7.39/kW/month. Additional assumptions in Appendix A.

Just lowering export payments in California will move customers to solar-plus-storage

Overall adoption of home solar and storage in California would slow down if solar export payments were cut. Under lower export rates, the economic rationale for customers would skew towards adding storage to each new customer-sited solar installation, as internal rates of return for solar-plus-storage get better than for solar-only (13% vs 10% for residential, or 8-year payback vs 10 years, 15.2% vs 14.7% for commercial, or 6-year payback). With a battery, customers can use more of the solar electricity generated so they rely less on compensation for exports.

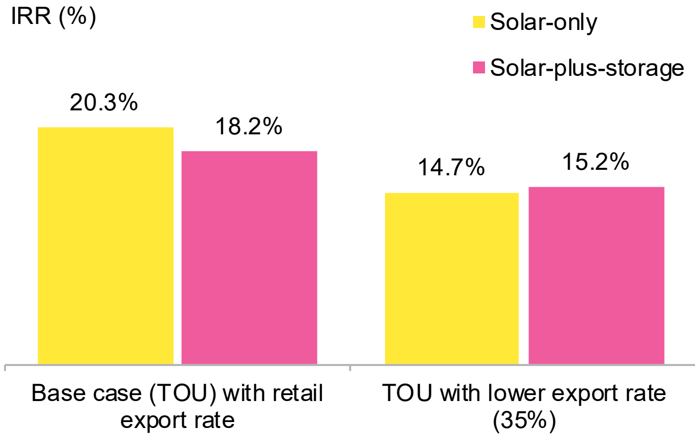
We modeled a scenario for residential and commercial solar where exports receive 35% of the applicable retail rate at the time of export. Unlike the 'All-in utility proposal' above, we kept TOU rates as they currently are and did not include a solar charge. For residential, the lower net metering payments deteriorate returns for both solar-only and solar-plus-storage, which range from 10-13% IRR respectively, increasing payback periods to 8-10 years. Solar-only systems are just within the payback threshold of 8 years, or 10% IRR, that households use to assess a capital investment. For commercial, returns for solar-only and solar-plus-storage would remain attractive to customers at 14.7% and 15.2% IRR, respectively, or a 6-year payback period.

Figure 78: Returns for California residential solar-only and solar-plus-storage under different export payment rates



Source: BloombergNEF. Note: 8kW PV and 5kW/14kWh battery systems, 12,000kWh/year home. Federal tax credits, rebates for storage assumed. TOU rate: Peak: 4-9PM $0.41/kWh, Off-peak: $0.17/kWh. Base-case export rate = 100% retail rate. Additional assumptions in Appendix A.

Figure 79: Returns for California commercial solar-only and solar-plus-storage under different export payment rates



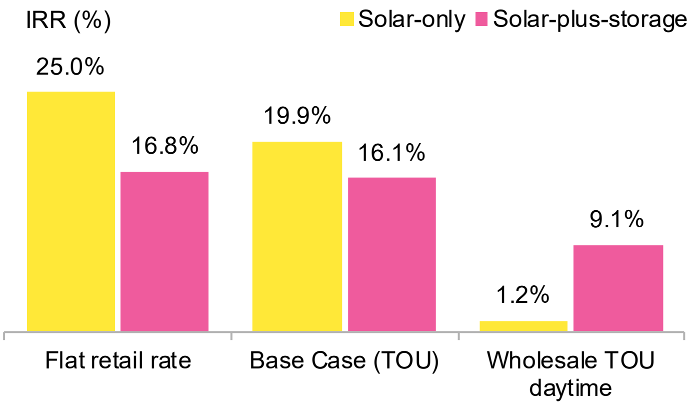
Source: BloombergNEF. Note: 100kW PV and 50kW/100kWh battery system, 166,000kWh/year office load. Federal tax credits, rebates for storage assumed. TOU rate: Peak: 4-9PM $0.36/kWh, Off-peak: $0.08/kWh, demand charge: $22.77/kW. Additional assumptions in Appendix A.

TOU can serve as a pricing tool to encourage more storage build

For residential and commercial systems, solar-only yields higher returns in both a time-of-use and a flat tariff scenario compared to the solar-plus-storage option, due to lower upfront costs. Yet, with the current time-of-use structure in California, customers are more inclined to add storage to their new customer-sited solar compared to when rates were flat. This is because returns for solar-only drop compared with a flat tariff structure, while the economics for solar-plus-storage remain almost the same. Solar-plus-storage yields the same returns in both scenarios because the battery charges from solar and helps to offset the highest electricity prices during the evening.

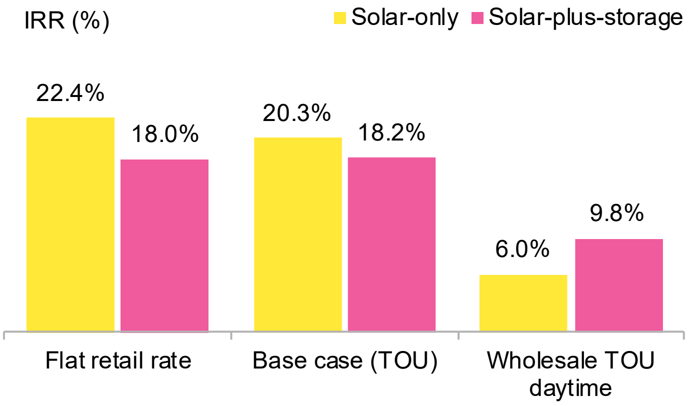
We modelled a more conservative time-of-use scenario, where utilities price daytime electricity for solar customers at about the wholesale rate ('Wholesale TOU daytime'). In this scenario, there is no economic incentive for either residential or commercial customers to install customer-sited solar without batteries. Returns for solar-plus-storage would be just under the threshold of 10% IRR or 8-year payback period. Despite poor economics, some homeowners and businesses may still choose to build customer-sited solar-plus-storage if they have other non-economic motivations, such as grid resilience.

Figure 80: Return comparison for California residential solar-only and solar-plus-storage with different TOU structures



Source: BloombergNEF. Note: 8kW PV and 5kW/14kWh battery systems, 12,000kWh/year home. Federal tax credits, rebates for storage assumed. Flat retail rate = $0.25/kWh. TOU rate: Peak: 4-9PM $0.41/kWh, Off-peak: $0.17/kWh. Wholesale TOU daytime: Peak: 4-9PM $0.44/kWh, Off-peak: $0.01/kWh. Base-case export rate = 100% retail rate. Additional assumptions in Appendix A.

Figure 81: Return comparison for California commercial solar-only and solar-plus-storage with different TOU structures



Source: BloombergNEF. Note: 100kW PV and 50kW/100kWh battery system, 166,000kWh/year office load. Federal tax credits, rebates for storage assumed. Flat retail rate = $0.13/kWh. TOU rate: Peak: 4-9PM $0.36/kWh, Off-peak: $0.08/kWh. Wholesale TOU daytime: Peak: 4-9PM $0.40/kWh, Off-peak: $0.01/kWh. Demand charge in all scenarios: $22.77/kW. Additional assumptions in Appendix A.

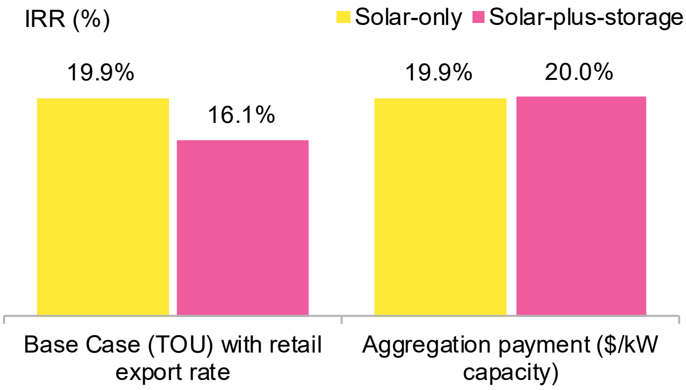
Lower export rates and TOU tariffs may also incentivize customers to shift loads to the daytime to absorb solar generation. Vehicle and heat electrification could increase load size and flexibility. In California, there are more than 900,000 electric vehicles as of August 2021, which can potentially be charged during the middle of the day.

Payments for grid services sweeten the deal for batteries

California is one of the first states in the U.S. where utilities, system operators and distributed energy providers piloted aggregation programs for customer-sited solar and storage. These virtual power plants aim to provide network and power capacity services to the grid during peak demand times or any other grid-constraining events. Such events are becoming more common as heat waves, wildfires and severe droughts in California have caused rolling blackouts and shortages of energy supply.

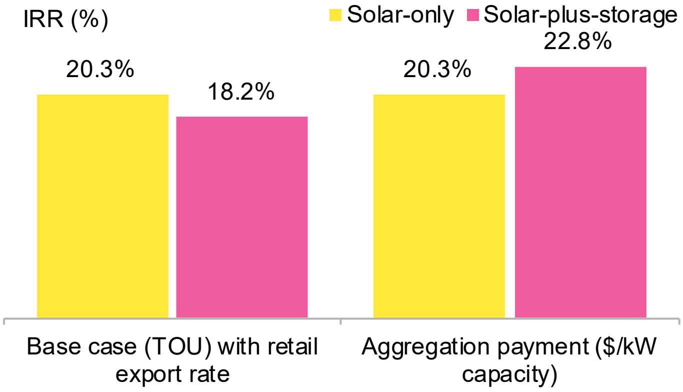
Programs that pay batteries on a $ per kW capacity basis per year make solar-plus-storage more appealing to both residential and commercial customers from a purely economic standpoint (Figure 82, Figure 83). On top of economic returns, many customers in California also value the short-term resilience that batteries provide during blackouts. Aggregation payments for solar and storage systems would incentivize every new customer-sited solar project in California to add a battery.

Figure 82: Returns for California residential solar-plus-storage systems with and without aggregation payments



Source: BloombergNEF. Note: 8kW PV and 5kW/14kWh battery systems, 12,000kWh/year home. Federal tax credits, rebates for storage assumed. TOU rate: Peak: 4-9PM $0.41/kWh, Off-peak: $0.17/kWh. Export rate = 100% retail rate. $100/kW capacity/year assumed for home solar and storage aggregation payments. Additional assumptions in Appendix A.

Figure 83: Returns for California commercial solar-plus-storage systems with and without aggregation payments



Source: BloombergNEF. Note: 100kW PV and 50kW/100kWh battery system, 166,000kWh/year office load. Federal tax credits, rebates for storage assumed. TOU rate: Peak: 4-9PM $0.36/kWh, Off-peak: $0.08/kWh. Demand charge in all scenarios: $22.77/kW. $100/kW capacity/year assumed for commercial solar and storage aggregation payments. Additional assumptions in Appendix A.

Reducing export rates can be offset by additional payments for batteries combined with streamlined permitting and interconnection

In places with high solar penetration, such as California, the trend toward cutting back on solar export compensation (net metering) in the future may continue. We modeled a scenario where other policies offset the lower returns from reduced export payments, to help support even deeper levels of customer-sited solar penetration. These policies include aggregation payments for batteries, new automated permitting and interconnection processes, as well as incentives that reduce labor costs in California.

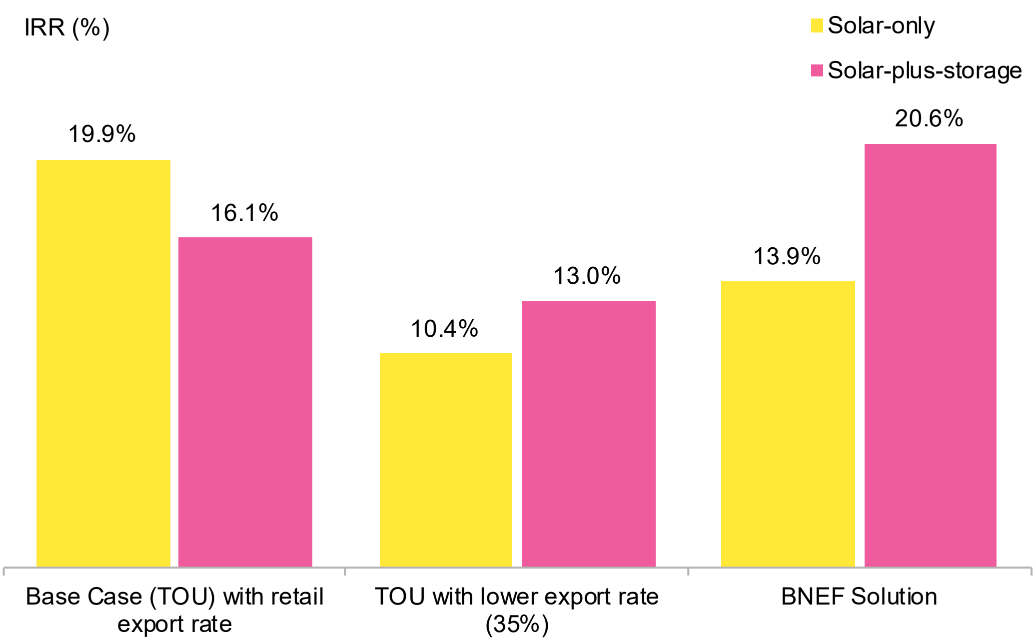
The two biggest installation challenges that solar installers face in the state (and in many other U.S. markets like New Jersey, New York or Massachusetts) are sluggish permitting and interconnection timelines, as well as shortages in qualified installation crews. According to home solar installers in California, these obstacles increase soft costs and installation costs by 20-25%.

California legislators have already introduced a bill (SB617) to streamline customer-sited solar and storage permitting and allow remote inspections, following Hawaii’s footsteps. Some municipalities like Santa Barbara and Berkeley have already started issuing automated customer-sited solar permits. Despite progress, there have also been some setbacks, as new licensing requirements in the state demand that solar and storage installations need to be done by an electrical contractor (as opposed to allowing solar installers to do the work), which limits the labor pool and may further increase soft costs.

In the 'BNEF Solution' scenario, returns for both residential solar and solar-plus-storage remain attractive to customers despite lower export payments. The scenario models export rates of 35% of the retail rate, aggregation payments, as well as lower upfront costs thanks to faster permitting and labor availability. Every new home solar customer would also add a battery in the new scenario given considerably higher returns compared with solar-only systems (20.6% IRR vs 13.9%, or paybacks of 5 vs 8 years).

From a grid stability perspective, one of the regulators' goals with lower net metering payments is to avoid too many customer-sited solar exports to overwhelm the distribution network during the day. If every new customer-sited solar system in California adds a battery, as the BNEF Solution scenario would encourage, policy makers and grid operators could ensure that customers use more of the solar at night instead of exporting it at the same time during the day.

Figure 84: Aggregation payments, streamlined permitting and interconnection, as well as better labor availability offset lower export revenues for California residential solar and storage



Source: BloombergNEF. Note: 8kW PV and 5kW/14kWh battery systems, 12,000kWh/year home. Federal tax credits, rebates for storage assumed. TOU rate: Peak: 4-9PM $0.41/kWh, Off-peak: $0.17/kWh. BNEF Solution scenario assumes lower export rates at 35%, reduced installation costs from automated permitting and lower labor costs, as well as aggregation payments for batteries of $100/kW capacity/year.

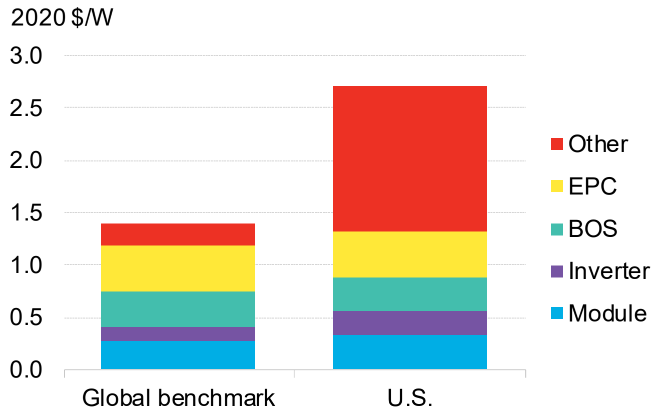
Rooftop mandates ensure new buildings have solar

In 2020, California was the first U.S. state to require rooftop solar on every new single-family building. In August 2021, the California Energy Commission expanded the rooftop solar mandate to include commercial and multi-family apartment buildings as well. As of August 19, 2021, the new mandate still has to be approved by the state's Building Standards Commission.

Solar installed when buildings are constructed is cheaper and delivers a clear value proposition, thanks primarily to lower soft costs. On average, a solar system adds about $10,000 to a new home, according to building industry analysts. This would translate to around $1.6/Watt assuming a 6kW solar system[26], which is about 40% cheaper than the average cost of retrofitting solar to existing homes in California.[27]

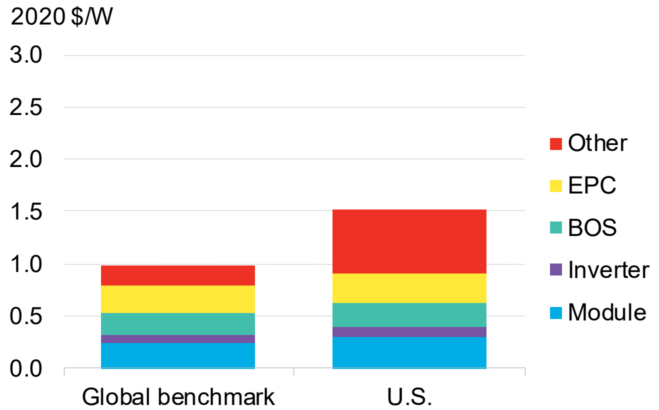
Solar companies could achieve this cost by reducing soft costs by 80%. Soft costs, in the form of customer acquisition and permitting, are a large component of rooftop solar costs in the U.S. where they account for 51% ($1.39/W) of the final residential solar price (see Figure 85). By comparison, soft costs make up 14% of BloombergNEF's global benchmark for residential PV capex. Solar companies in California spend a lot of time and money to acquire a single new customer. By partnering with home builders, solar companies can cut down almost all of their sales expenditures. For permitting, builders and installers issue all of the required building permits for a new house at the same time, which allows for additional cost savings.

Figure 85: Residential PV capex breakdown, 2021



Source: BloombergNEF

Figure 86: Commercial PV capex breakdown, 2021



Source: BloombergNEF

Installing solar panels on new homes could also save on construction costs, such as labor and scaffolding. While there is a clear overlap between a roofer's work and the solar panel installation, these savings may be limited as roofing companies in the U.S. prefer to subcontract the entire panel installation and electrical work to solar installers, for three different reasons. First, roofers lack the expertise or willingness to deal with solar equipment purchases, including assessing product quality or understanding price and supply chain dynamics. Secondly, roofing companies want to avoid any liability for failures in the solar system that could cause any harm to the property and its inhabitants. Third, roofing companies would also need to become certified solar installers, which would require hiring new electricians and certified solar contractors, which are currently limited in California as the market grows.

California's single-family home solar mandate faced several challenges in its first year of introduction. Barriers to installing solar on new homes included a limited amount of suitable roof space in dense areas as well as off-site solar alternatives like community solar. Builders were worried that the mandate would raise already high costs of new homes in California. Reportedly, construction companies used very aggressive energy-efficiency estimates to limit the size of the solar system and keep home costs down.

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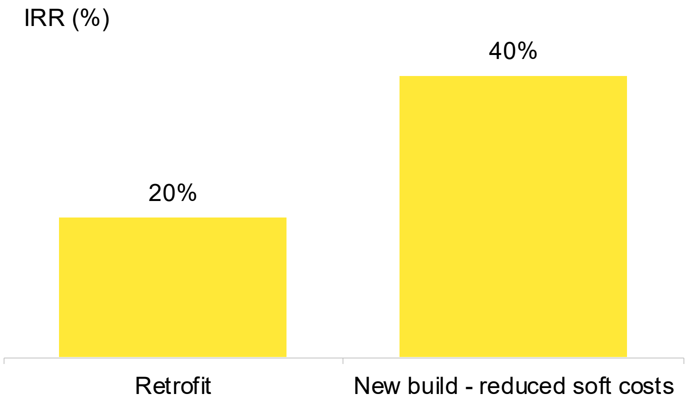
[26] This is smaller than the 8kW state average for retrofits on existing homes. Reportedly solar systems are smaller on new construction buildings than for retrofits. solar systems than the average ac

[27] $2.55-2.75/Watt between 2020 and June 2021.

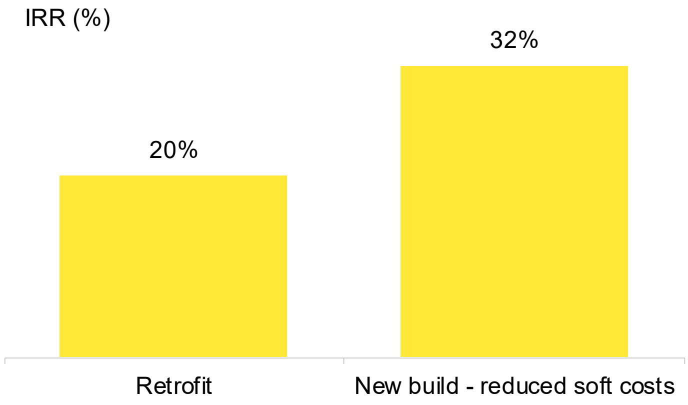
In California, we estimate that returns on new construction solar are around 20 percentage points higher than for retrofits. At IRRs of 40% for residential and 32% for commercial, adding solar to new buildings should be a 'no-brainer' (see Figure 87 and Figure 88). We assume that solar installers can cut their soft costs by 80% and that builders pass on full solar installation costs to homeowners or owner-occupiers of commercial properties. Households and businesses can then recover the investment through utility bill savings and export credits.

Figure 87: Returns for residential solar in California – retrofit versus new construction



Source: BloombergNEF. Note: Assumes 8kW PV system, 12,000kWh/year home. Federal ITC applied. Export rate = 100% retail rate. TOU rate: Peak: 4-9PM $0.41/kWh, Off-peak: $0.17/kWh. Retrofit capex = $2.8/W, New construction capex = $1.6/W. Additional assumptions in Appendix A.

Figure 88: Returns for commercial solar in California – retrofit versus new construction



Source: BloombergNEF. Note: 20kW PV system for an office consuming 40,000kWh/year on a EUR 0.10/kWh variable rate. Subsidized compensation for exports and 'self-consumption premium' under self-consumption scheme. Retrofit capex = $1.0/W, Reduced soft costs capex = $0.8/W, Reduced construction costs = $0.7/W. Additional assumptions in Appendix A.

3.6. Australia

Australia is one of the most decentralized energy markets in the world

Australia has benefited from a decade of booming customer-sited solar sales, installing more than 3GW in 2020 alone (Figure 89). Customer-sited solar has moved beyond a niche product to essentially becoming a standard addition to new homes. As of the end of 2020, almost a third of households had solar (Table 5).

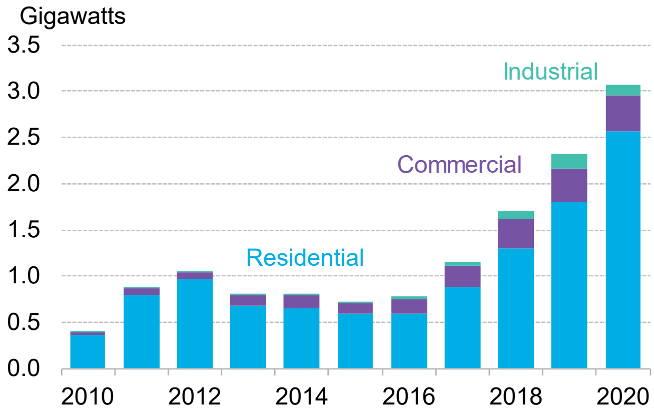
Table 4: 2020 Australian customer-sited solar penetration of total buildings

Sector	Penetration
Residential	32%
Commercial	4%
Industrial	1%

Source: BloombergNEF, Clean Energy Regulator

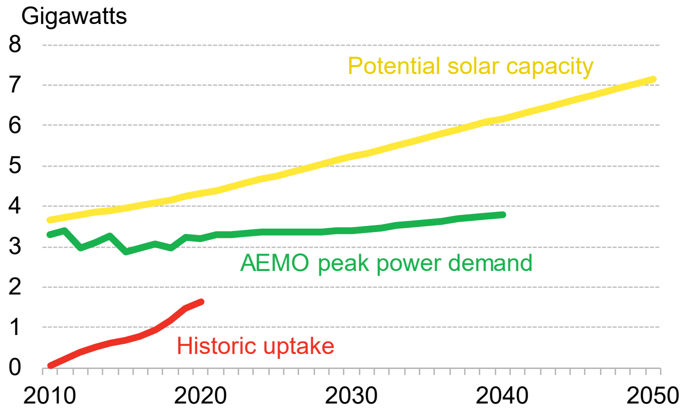
The uptake is even more dramatic in South Australia, where questions are now being raised over whether there is even enough power demand to support South Australia's customer-sited fleet. Future power demand could come from an electrified transport fleet, or hydrogen-producing infrastructure. Vehicle electrification will add load to the grid and could be supplied by customer-sited solar if charging occurs during the day. Installed capacity in the region is already equivalent to more than half of AEMO's peak power demand (Figure 90), a figure that disguises some more acute grid conditions such as on October 11, 2020, when customer-sited solar generation got to meet three quarters of power demand at certain hours.[28] Such a radical change in the energy system has required a rethink on how power networks, retailers and customers all interact within the energy market.

Figure 89: Annual Australia behind-the-meter solar capacity additions



Source: BloombergNEF

Figure 90: South Australia peak power demand versus potential and actual customer-sited solar capacity



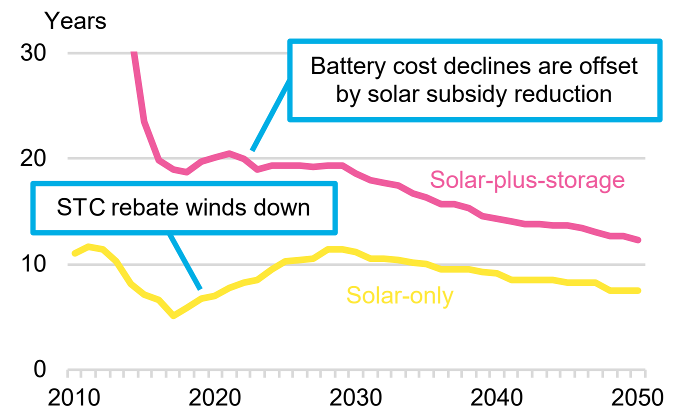
Source: BloombergNEF, Australian Energy Market Operator (AEMO). Note: AEMO's estimate for peak power demand generally occurs during the evening, outside of peak solar production hours.

Superior economics have made households leaders in Australia's customer-sited solar market. Australia's residential sector benefits from a high level of home ownership, a relatively affluent society and a sunny climate. Generous state-sponsored feed-in-tariff schemes in 2010-12 helped kick-start Australia's solar market. In the meantime, federal Small-scale Technology Certificates (STCs), which act as an upfront solar subsidy, have attracted customers to the market, promoting competition. In fact, installers have become so cost competitive that Australia now has access to the cheapest pre-subsidy solar panels in the world, outside China. Combined with high retail electricity prices, customers can achieve attractive returns on solar. While STC rebate winds down in the short term, this cost decrease trend is set to continue in the mid-term (Figure 91).

Australian households pay more for their power than businesses, meaning the benefits of customer-sited solar self-consumption are greater. Businesses also have access to federal government subsidies, but low variable rates mean the cost of solar will need to fall further before mass-market adoption occurs on economics alone; in oh adoption is growing already as companies adopt solar to meet renewable energy targets (Figure 92).

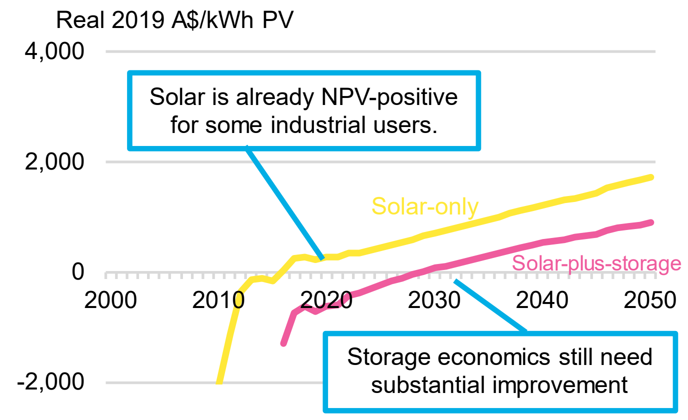
[28] On October 11, 2020: *Record Solar Supplies 100% of South Australia's Power*

Figure 91: Average payback period of behind-the meter solar and storage for Australian households



Source: BloombergNEF. Note: This is a sample average for Australia. System sizes, STC solar rebates, variable rates and export rates vary by state and over time. As reference, average variable rate in 2020: A$0.24/kWh. Average load also varies by state.

Figure 92: Average NPV of behind-the meter solar and storage for Australian industrial users



Source: BloombergNEF. Note: Positive NPV does not necessarily mean businesses purchase a solar system, since investment decision will depend on the relative value of this compared to other opportunities.

Solar exports from oversized household systems are overloading the grid

Accommodating solar exports is the most immediate issue grid operators are facing. The average new residential solar system size is now over 7kW. On a typical day for a 6kW system, most energy is exported (Figure 93). Suburban distribution networks which previously used to deliver power downstream from large coal plants to homes are now expected to accommodate a reversal in power flows.

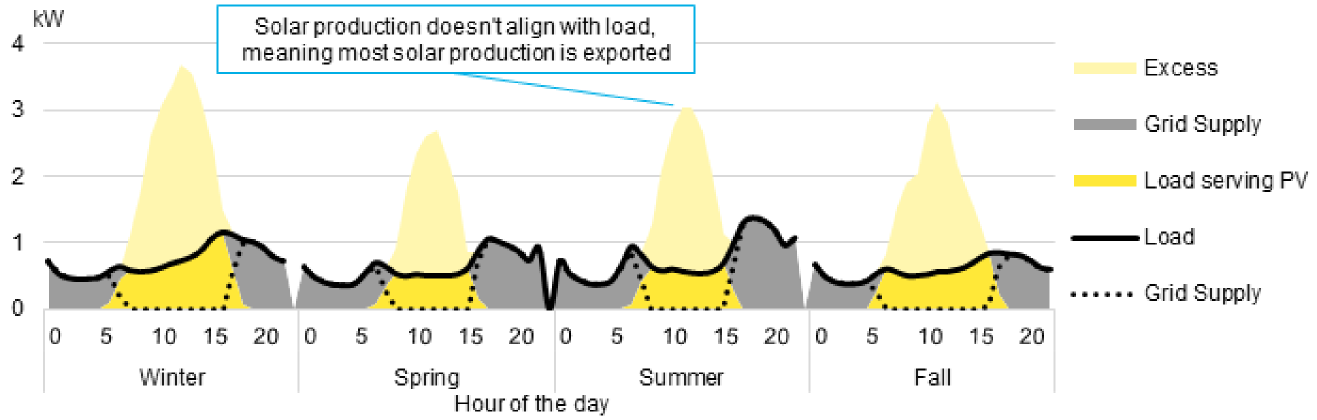
Distribution grids absorb intermittent solar power out of people's homes and deliver it to their neighbors, that is, if they are not themselves also exporting solar. This activity has become so widespread that distributors are struggling to stabilize their networks and have been forced to introduce static export limits, which curtail exports over a certain kW output. In all Australian states, these export limits are less than 10kW, unless special permission is granted. This means households are largely unaffected, while most businesses will face more stringent rules to connect their large solar systems to export.[29]

The value of solar exports will likely decline rapidly. Most retail tariffs reimburse Australian consumers for exported solar power at a rate which resembles the average wholesale value. But solar supply is cutting into power demand, leading to a drop in the midday value of wholesale power. Zooming into South Australia, Figure 94 shows a period in 2020 where behind-the-meter

[29] Although many business-sited solar systems have been given permission to export to date, particularly for medium systems, it will be harder and harder to receive this approval. Small, residential systems are entitled to exports, and the popularity of these systems is 'crowding out' the overall hosting capacity. Even in areas without households it will become difficult to find carrying capacity as business-sited solar moves beyond early adopters to higher levels of penetration.

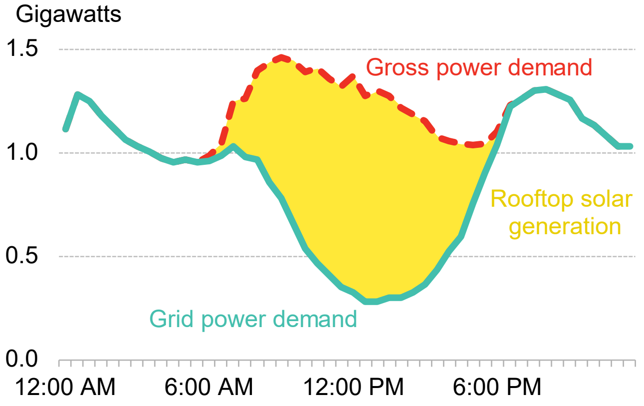
solar met more than three quarters of the region's power demand.[30] Consumers can still find tariffs with high export rates, which are designed to lure them away from other retailers. Yet, most of the time they would be expected to pay more for the energy they import, in order to access those higher export rates.[31]

Figure 93: Power demand, solar generation and net grid-facing load for an average South Australia household with 6kW solar



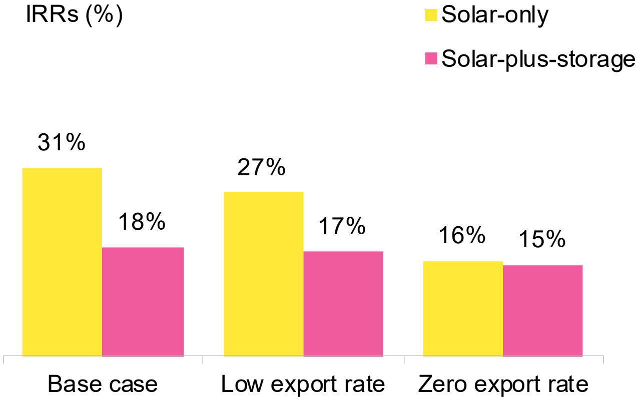
Source: BloombergNEF

Figure 94: South Australia power demand on October 11, 2020



Source: BloombergNEF, AEMO

Figure 95: IRRs of South Australia residential solar and storage under different solar export tariff scenarios



Source: BloombergNEF. Note: Scenarios uses a 6kW solar system paired with a subsidized 12kWh battery, 'Base case' assumes A$0.12 per kWh exported and 'Low export rate' assumes A$0.09 per kWh exported.

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[30] Combined utility-scale and small-scale solar met 100% of the state's power demand during this period.

[31] An example is retailer AGL, whose Residential Super Saver rate has a A$0.93 daily charge, A$0.32/kWh usage and A$0.08/kWh solar export, while the Residential Solar Savers rate offers A$0.99 daily charge, A$0.34/kWh usage and A$0.12/kWh for solar export.

Lower export payments would result in poorer economics for solar-only projects. At current average export payments (A$0.12 per kWh), South Australian households can earn 31% IRRs over the 25-year life of a solar system, equivalent to a 4-year payback period. A 25% reduction in the export payment would not reduce the IRR of a solar-only system significantly, dropping it to 27% (Figure 95). This illustrates that the primary value of behind-the-meter technology still comes from self-consumption, even when most energy is being exported. In an extreme scenario where the export rate is reduced to zero, the system would deliver an IRR of 16%, a 7-year payback. This is still a worthwhile investment for most households.

Table 2: 2020 Australian behind-the-meter storage penetration of total buildings

Sector	Penetration
Residential	1.2%
Commercial	0.1%
Industrial	0.0%

Source: BloombergNEF, Sunwiz

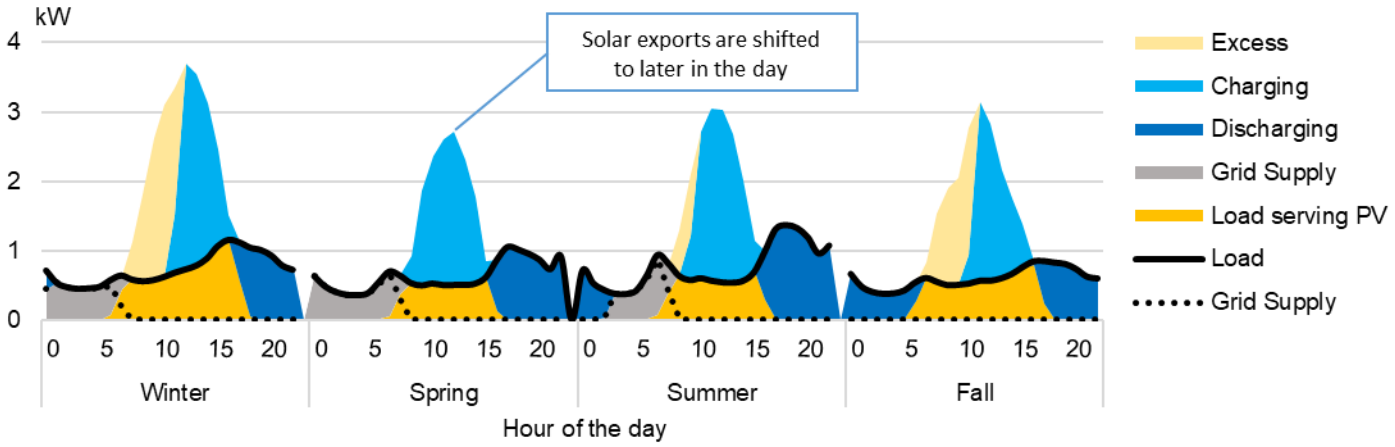
Pairing solar with storage will help increase hosting capacity

Behind-the-meter batteries are ideal substitutes for solar exports. Rather than exporting solar power to an already-overloaded grid, Australia's market operators and network companies are hoping that consumers will find it more beneficial to store surplus energy in a battery and use it later (Figure 96). Flexible loads can also help absorb solar generation and reduce exports.

South Australia in particular has the highest penetration of customer-sited solar in the world and is being forced to address issues of solar oversaturation before anywhere else. The state government has acted by introducing a behind-the-meter battery subsidy. As is shown in Figure 95, falling export rates boost the relative economics of solar-plus-storage compared to solar-only, increasing the chances batteries are added to new and existing solar systems.

Once solar exports are worth so much less, South Australia residential customers should find the economics of solar-plus-storage match that of solar-only. It is unclear if customers would prefer solar-only or solar-plus-storage systems at this point. Solar-plus-storage systems are capex heavy, yet they can bring non-economic benefits such as blackout protection. It is uncertain when power retailers will reduce export tariffs, so in the meantime regulators and networks are looking to incentivize storage using other tools.

Figure 96: Power demand, solar generation, storage charging profile and net grid-facing load for an average South Australia household with 6kW solar and 12kWh storage



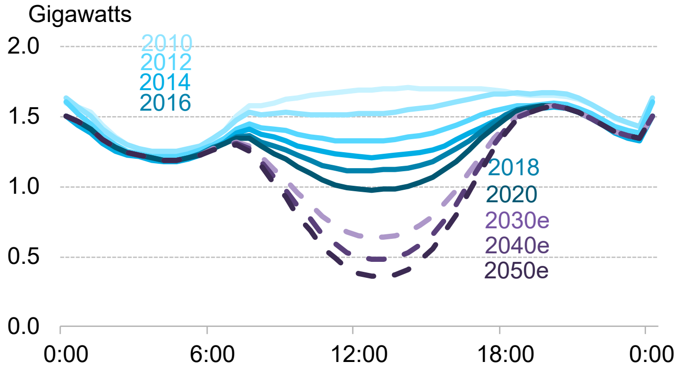
Source: BloombergNEF

Customer-sited solar accelerates the transition to cost-reflective tariffs

Distribution networks are transitioning to cost-reflective tariffs due to the growth of customer-sited solar. Traditionally, network companies have invested in infrastructure based on the peak hourly demand that needs to be served, while costs have been recovered on a per kWh basis from energy delivered. As Figure 97 shows, the growth of customer-sited solar is leading to an imbalance in this relationship, eroding energy demand without reducing peak demand.

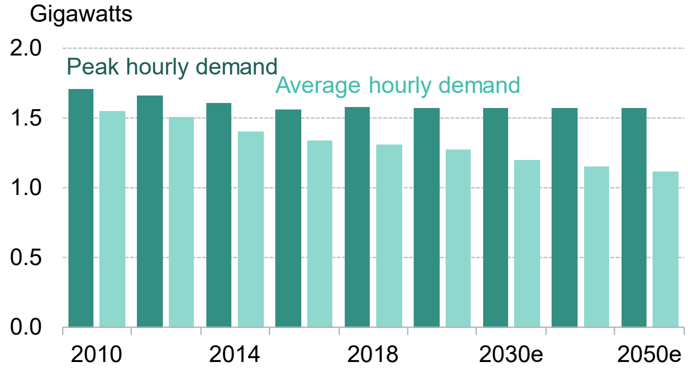
The Australian Energy Regulator (AER) is pushing networks to adopt tariffs which more closely reflect their costs. Australian businesses already have some time-of-use element in their retail bill, whereas three quarters of residential users are still on a flat retail tariff.[32] Australian network companies are gradually changing their tariffs to be more cost-reflective by introducing a time-of-use (TOU) or a demand-based ($/kW) charges for households, and increasing these components for businesses. The AER estimates that by the end of 2023 roughly 40% of all Australian households could have a time-based or demand-based network charge in their retail bill.

Figure 97: Average intraday operational demand in South Australia including forecasted behind-the-meter capacity



Source: BloombergNEF, AEMO

Figure 98: Hourly operational demand in South Australia including forecasted behind-the-meter capacity



Source: BloombergNEF, AEMO

If this trajectory continues, most consumers should shift to a time-of-use tariff over the coming years. Australia has a competitive retail market, which allows consumers to choose any power retailer, and tariff, they wish. Retailers are responsible for covering network charges and recouping the costs from customers, but do not have to pass these charges through directly. This means regulators and networks cannot force tariff structures on consumers, and it is possible for consumers to choose a flat retail tariff even though the underlying network charge may be cost-reflective and time-varying.

Nonetheless, BloombergNEF expects that most customers will find themselves on a TOU tariff within the next decade. This is because retailers that offer flat tariffs will need to charge a premium due to a mismatch between revenue and volatile network and wholesale power costs. This should make cost-reflective retail tariffs more attractive. Even though several networks favor demand-based charges, we expect that TOU will become the most popular cost-reflective tariff since it is the easiest for consumers to understand.

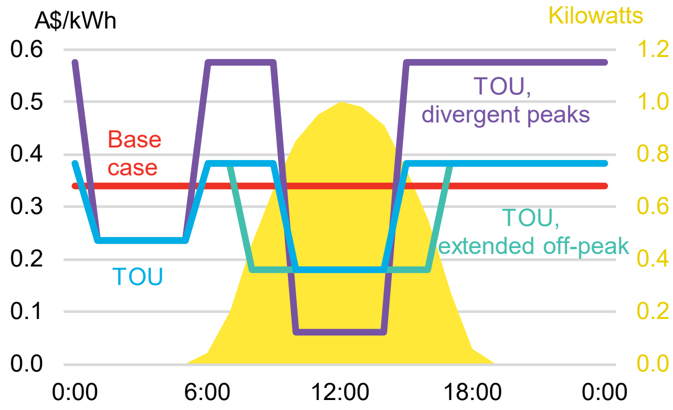
[32] AER, Retail energy market performance update for Quarter 3, 2020-21

TOU tariffs could push more customers to buy batteries

Time-of-use (TOU) retail tariffs can improve the economics of behind-the-meter storage. Distribution network provider South Australia Power Networks (SAPN) has made it mandatory for any customer with a smart meter to be charged a 'solar sponge' network tariff, where it charges a lower rate during solar hours. Many TOU retail tariffs now reflect this network charge (see Figure 99). Relative to the flat retail tariff that most South Australians are on, this would reduce the IRR on a solar-only system from 31% to 28% (Figure 100), meaning payback period remains unchanged at 4 years. The difference is small since there is still solar production during peak hours.

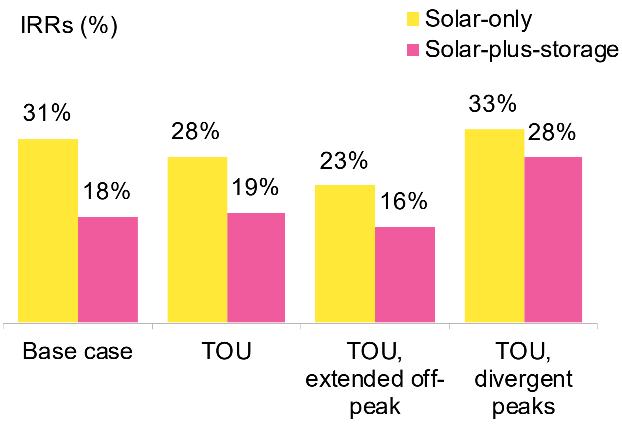
As solar additions continue, generation will grow, and it is likely that the off-peak period will be extended to account for the large amount of power still being produced in the mornings and afternoons. By adding two hours in the morning and two in the afternoon to the off-peak period (*TOU, extended off-peak* scenario), IRRs of a solar-only project would drop to 23%, just 7 percentage points above solar-plus-storage, lengthening the payback period to 5 years.

Figure 99: Retail tariff scenarios for South Australia households



Source: BloombergNEF

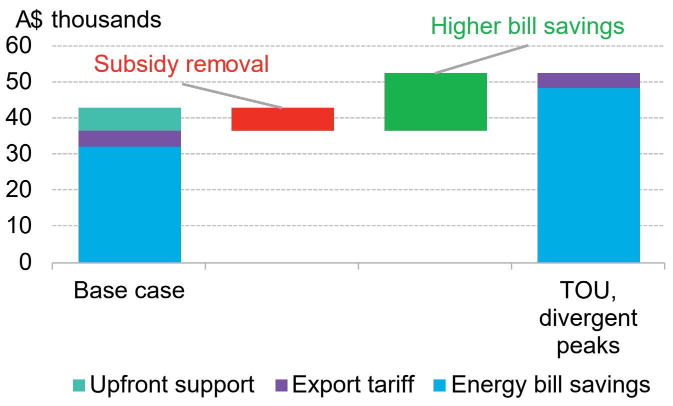
Figure 100: IRRs of South Australia residential behind-the-meter solar and storage under different retail tariff scenarios



Source: BloombergNEF. Note: Scenarios uses a 6kW solar system paired with 12kWh of storage.

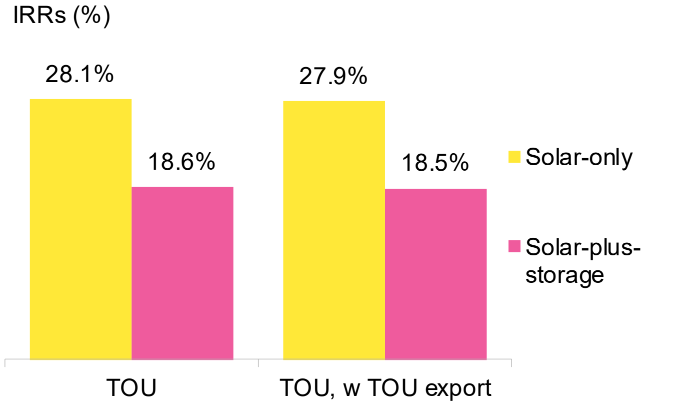
To really encourage the uptake of storage, widening the difference between peak and off-peak periods is necessary. In the fourth scenario (*TOU, divergent peaks*), we assumed the off-peak rate is dropped by 50%, while the peak rate is boosted by 50%, which represents a view that retailers may pass on the cost-reflective network tariffs that are driven by increased congestion caused by solar output, in addition to the already variable wholesale market prices. This increases the IRR of a solar-plus-storage system to 28% and reduces the payback period to 4 years. This would increase the economics of solar-plus-storage by so much that it would offset the removal of the federal solar subsidy and state storage subsidy (see Figure 101). The value of daytime solar production will continue to fall, while flexibility will become more important. This makes it likely more utilities will make daytime off-peak periods longer, while also increasing their difference from peak periods.

Figure 101: NPV of South Australia residential solar-plus-storage systems under different scenarios



Source: BloombergNEF. Note: Scenarios uses a 6kW solar system paired with 12kWh of storage.

Figure 102: IRRs of South Australia residential solar and storage with a TOU retail rate and flat, or TOU-based export tariff



Source: BloombergNEF. Note: Scenarios uses a 6kW solar system paired with 12kWh of storage.

Regulators are evaluating how they can best pass on time-of-day value of energy to customers. The Australian Energy Market Commission (AEMC) has recently made a rule change that would allow networks to charge customers for exports above a certain limit, according to the time of day.[33] Retailers would then have a choice to pass these on to end-users, which most likely they would. Based on our analysis the impact would not be significant at a 50% export rate (Figure 102), as either way it would be more economic to arbitrage and offset evening rates than to export during solar hours.

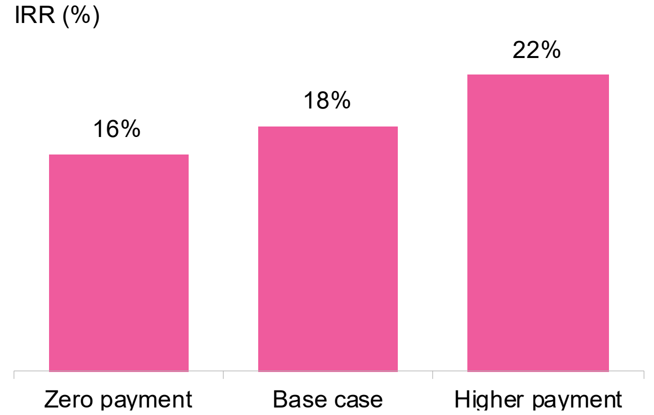
Aggregation can assist residential battery uptake while also balancing the grid

Australia is one of the world leaders in virtual power plant (VPP) development. VPPs connect decentralized generators into a group which can be managed by an operator. Currently, there are over 50 VPPs active in Australia. Since uptake of energy storage by C&I users is so low, there is very little evidence of aggregated C&I batteries being used outside trials. Most VPPs are operated by power retailers and give households some form of payment to enroll their battery into the program.

These payments can be lucrative and can impact a customer's purchasing decision. The future of these payments is uncertain, however. In our base case below, we assume batteries receive A$65/kW/year to be enrolled in a VPP. If VPPs became more lucrative and this value were raised to A$140/kW/year, the IRR of a solar-plus-storage system would increase from 18% to 22% (Figure 103), a 6 year payback in both scenarios. Likewise, if VPPs become too costly to manage and payments fall to zero, the IRR of a solar-plus-storage system would fall to 16%, still managing a 6-year payback.

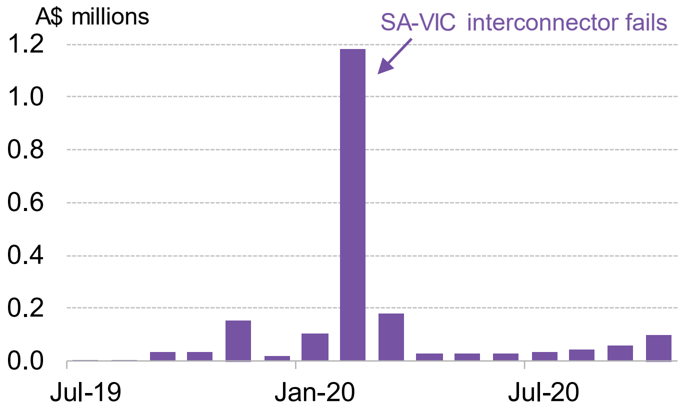
[33] TOU export rates have already become mandatory in all of West Australia, and it is also an option in Victoria - although it has very low uptake there

Figure 103: IRRs of South Australia residential solar-plus-storage under different aggregation payment scenarios



Source: BloombergNEF. Note: 6kW solar paired with 12kWh of storage, 'Base case' aggregation payment is A$65/kW/year and 'Higher aggregation' payment is A$140/kW/year.

Figure 104: IRRs of South Australia residential solar-plus-storage under different aggregation payment scenarios Monthly Frequency Control and Ancillary Services (FCAS) market revenues for Tesla's VPP



Source: BloombergNEF, AEMO

One of the key challenges for VPPs is lack of market access. Currently, a VPP needs to be tied to a retailer to be able to pull value from the wholesale power market. Separately, for the Frequency Control and Ancillary Service (FCAS) market, there are several hurdles, such as minimum size requirements, which need to be overcome for a VPP to participate. Even then, returns from this market can be volatile (Figure 104). Lastly, Australian networks have been hesitant in contracting grid services from VPPs due to a lack of experience and risk of unreliability. These are all problems that can be overcome with the right regulation changes, and the Energy Security Board has signaled that promoting greater demand-side participation is a top priority for its post-2025 reform of the National Electricity Market. However, it is unclear when these reforms will take place and what level of benefit they would provide to VPPs.

Export limits mean that storage business case for large businesses will depend on their demand profile

There are static export limits in most of Australia's distribution networks, which means that most large, industrial-sized systems will be sized to maximize self-consumption while avoiding exports.[34] Because of this, outside of government subsidies, economic value for businesses comes from self-consuming solar to offset retail power costs. It also means that if a commercial user wants to add storage, they need to install a solar system that is large enough to have excess capacity to fill a battery, yet not so large that there's excess beyond what the battery can absorb and power is curtailed and wasted.

Importantly, since industrial users pay low variable rates for power, the returns on a solar system are lower. Unlike households, there is enormous variance in businesses' load profiles and total demand. For this analysis BloombergNEF kept technology assumptions and total demand constant while flexing profile shape to illustrate the importance of the user type. The three typical

[34] The 3-phase export limit in most networks is 10kW without permission. Note that rates, demand profiles and system sizes can vary significantly and mean economics will vary across Australia

profiles that were tested were a warehouse, a manufacturer and an office, see Figure 105, Figure 107 and Figure 109. For the solar-plus-storage cases, we assumed a larger solar system than in the solar-only cases.

Figure 105: Average profile of warehouse user (1GWh in annual power demand)

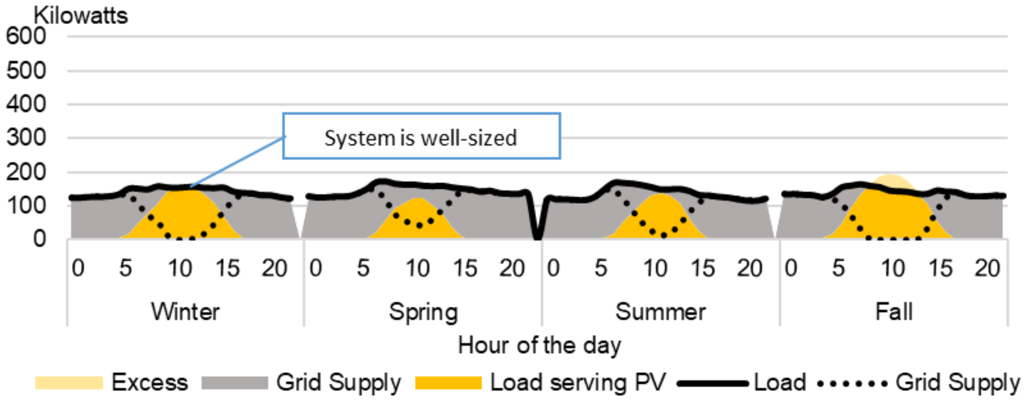
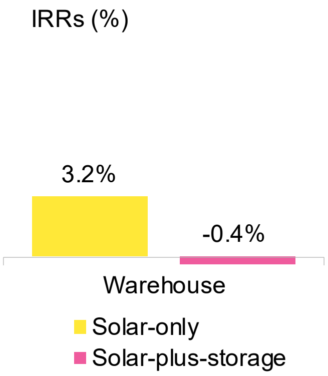


Figure 106: Warehouse IRRs



Source: BloombergNEF. Note: Assumes 300kW PV for Solar-only, and 600kW PV with 500kWh battery for solar-plus-storage.

Figure 107: Average profile of manufacturer user (1GWh in annual power demand)

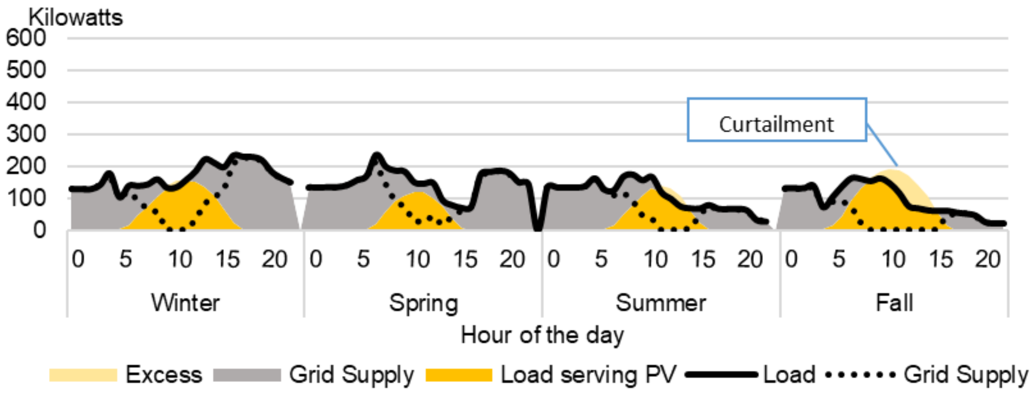
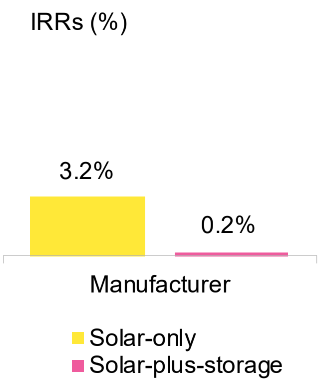


Figure 108: Manufacturer IRRs



Source: BloombergNEF. Note: Assumes 300kW PV for Solar-only, and 600kW PV with 500kWh battery for solar-plus-storage.

Figure 109: Average profile of office user (1GWh in annual power demand)

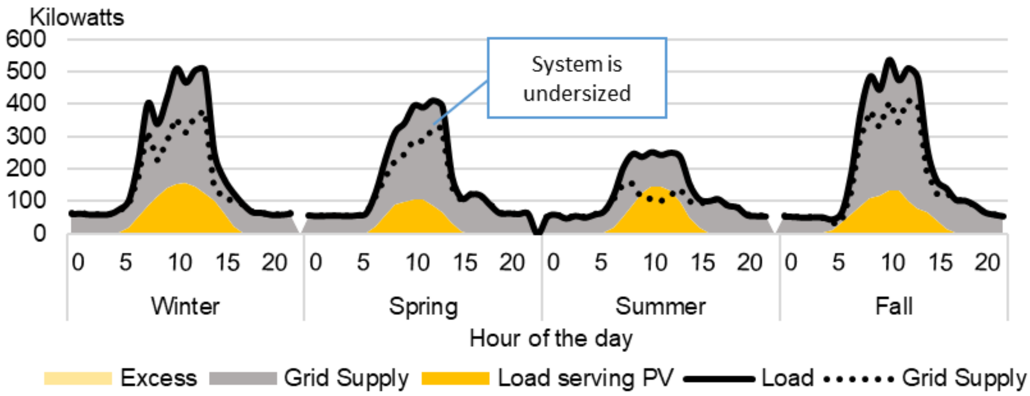
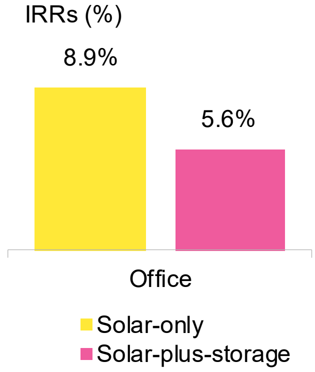


Figure 110: Office IRRs



Source: BloombergNEF. Note: Assumes 300kW PV for Solar-only, and 600kW PV with 500kWh battery for solar-plus-storage.

Looking ahead, large commercial solar will become more attractive with falling costs, so bigger systems will come online at a time when there is even more residential solar already on the grid. With that, it's more likely networks and market operators will require or incentivize solar with limited exports.

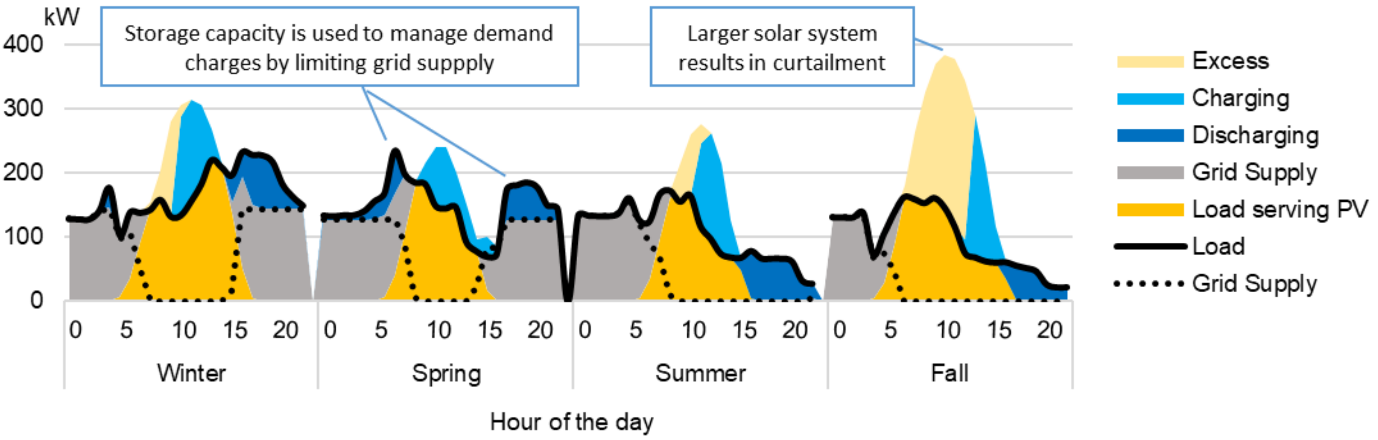
With limited exports, large businesses' load profiles significantly impact economics and define the size of solar that can be installed.[35] Figure 106 and Figure 108 show that for the warehouse and manufacturer load profiles modelled, IRRs are low, at about 3% (or 18-year payback). This is because some solar generation is being curtailed, and the system is having a minimal impact on demand charge reduction. Even though this means these users will not be losing money, it's likely they could find alternative investments which would deliver a higher IRR.

In contrast, the office profile is well matched to solar output and has an IRR of 9%, with a lower payback period of 11 years. For this reason, businesses with daytime-intensive operations have been early adopters. These include shopping centers, universities, farms, food processing centers and mines, among others. Other businesses may find non-economic benefits to solar such as the opportunity to decarbonize operations and hit green targets. Businesses will need to determine on a case-by-case basis whether on-site solar or renewable PPAs will be the most suitable way to pursue this. Vehicle and industry electrification will change the size and shape of commercial and industrial loads and impact this consideration.

Demand charges can help the poor economics of storage

Due to the low value of offsetting load with solar, low power prices also undermine the economics of behind-the-meter storage for industrial users. This is despite businesses being exposed to both TOU retail rates and demand charges. As Figure 111 shows, a variable load can make sizing a solar-plus-storage system tricky. Storage remains simply too expensive to be worthwhile for users that have demand profiles similar to warehouse and manufacturer loads. This will change as both solar and battery costs decline.

Figure 111: Figure showing net grid-facing load for a NSW manufacturer with solar-plus-storage

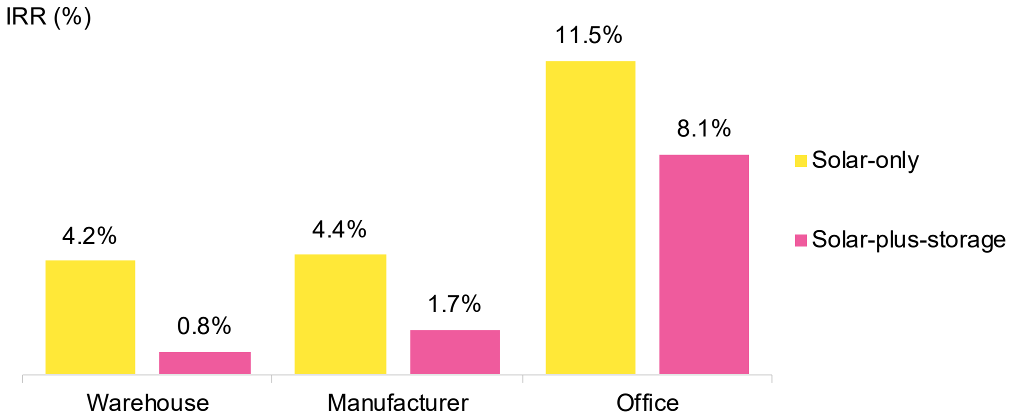


Source: BloombergNEF. Note: Scenario uses 300kW PV paired with a 500kWh battery.

35 Large businesses have optimized their load profile to be as flat as possible to achieve cost efficiency. There is, therefore, a range of opportunities to be captured by load shifting and changing manufacturing process.

If networks' revenues continue to be eroded by solar, it is likely that they will increase the value of their demand charges. This will have the added effect of encouraging demand-side flexibility. When demand charges are increased by 50%, shown in Figure 112, the economics of solar-plus-storage are improved. The higher IRRs are still not enough to make solar-plus-storage a worthwhile investment for businesses with profiles like the warehouse and manufacturer. For users with an office-like profile, the IRR of solar-plus-storage is boosted from 5.5% to 8.1%, reducing the payback period from 13 to 9 years. This is due to the larger solar system and a reduction in demand charges.

Figure 112: IRRs of NSW industrial behind-the-meter solar and storage with different user profiles and a 50% increase in demand charges



Source: BloombergNEF. Note: Scenarios uses a 300kW solar system paired with 500kWh of storage.

The priority for policy makers in Australia is to manage solar exports and integrate higher penetrations of customer-sited solar. Storage subsidies, such as those in South Australia, are helping to kick-start the storage market. Tariff design will be key to the next stage of market development – supporting ongoing addition of storage without subsidization. TOU tariffs for households will enable solar-plus-storage to be valued and earn returns, even as daytime value of solar generation and utilities try to reduce solar exports. Additional revenues from demand response through an aggregator may also help improve economics. Meanwhile demand charges for C&I customers will be central to storage uptake in that sector, and could help integrate more solar.

Appendix A. Methodology and assumptions

All values in tables below are in 2021$ real terms. Economics are modelled based on retail rates at commissioning (in reality, retail rates will likely change over the course of the lifetime of the solar and storage system). Base case and TOU retail rates are generally sample rates used to exemplify economics in the country/region but in reality may vary significantly across utilities within a country, as well as by type of and size of load (small commercial, industrial and agricultural loads often have different rates).

A.1. France

Table 5: Assumptions used in France analysis

Modelled case / sensitivity	Load	Retail rate	Export rate	Solar system assumptions	Storage system assumptions	Other revenues or support	Policy / scenario assumption
Base case	Residential (5,354 kWh/year load)	Variable: 0.1582 EUR/kWh ($0.19/kWh)	0.10 EUR/kWh ($0.12/kWh)	$1.4/W 5.2kW	$642/kWh 2.6W/7.2kWh	“other solar support” capex subsidy for the first five years of the project – 0.07euros/kWh	Exports compensated at the self-consumption scheme rate with an added capex support payment for the first five years of the project’s lifetime
	Commercial (large office 40,000 kWh/year)	Variable: 0.1035 EUR/kWh ($0.12/kWh)	0.06 EUR/kWh ($0.07/kWh)	$1.0/W 20kW	$513.88/kWh 10kW/20kWh	“other solar support” capex subsidy for the first five years of the project – 0.04euros/kWh	Exports compensated at the self-consumption scheme rate with an added capex support payment for the first five years of the project’s lifetime
TOU	Residential (5,354 kWh/year load)	2021: Variable peak: 6AM-10PM, 0.178 EUR/kWh ($0.21/kWh) Off-peak: 10PM-6AM, 0.13 EUR/kWh ($0.15/kWh) 2025 – 2040: 2020 rates X1.1	Unsubsidized scenario: 0.37 x retail rate Subsidized scenario: same as base case	Base case size Capex: 2021: $1.4/W 2025: $1.2/W 2030: $1.1/W 2040: $0.8/W	Base case size 2021: $642/kWh 2025: $496/kWh 2030: $393/kWh 2040: $302/kWh	Unsubsidized scenario: None Subsidized scenario: same as base case	Unsubsidized scenario: exports compensated at the wholesale rate Subsidized scenario: same as base case

	Commercial (large office 40,000 kWh/year)	2021: Variable peak: 6AM-10PM 0.113 EUR/kWh ($0.13/kWh) Off-peak: 10PM-6AM 0.077 EUR/kWh ($0.09/kWh) 2025 – 2040: 2021 rates X1.1	Unsubsidized scenario: 0.37 x retail rate Subsidized scenario: same as base case	Base case size Capex: 2021: $1.0/W 2025: $0.9/W 2030: $0.7/W 2040: $0.6/W	Base case size 2021: $513.88/kWh 2025: $396/kWh 2030: $314/kWh 2040: $242/kWh	Unsubsidized scenario: None Subsidized scenario: same as base case	Unsubsidized scenario: exports compensated at the wholesale rate Subsidized scenario: same as base case
New construction	Residential (5354 kWh/year load)	Base case	Base case	Reduced soft costs: $1.2/W Reduced soft + construction costs: $1.0/W	N/A	Base case	Base case
	Commercial (large office 40,000 kWh/year)	Base case	Base case	Reduced soft costs: $0.8/W Reduced soft + construction costs: $0.7/W	N/A	Base case	Base case

Source: BloombergNEF; Total Energie (commercial electricity tariffs); EDF (residential electricity tariffs)

A.2. Spain

Table 2: Assumptions used in Spain analysis

Modelled case / sensitivity	Load	Retail rate	Export rate	Solar system assumptions	Storage system assumptions	Other revenues or support
Base case	Residential (4,046 kWh/year load)	Variable: 0.22 EUR/kWh	0.05 EUR/kWh (assumed average rate)	$1.38/W 4.3kW	$642/kWh 2.6W/7.2kWh	None Exports compensated at approx. wholesale rate on average for grid-connected small systems
	Commercial (40,000 kWh/year): • Large Office	Variable: 0.18 EUR/kWh	None	$1.0/W 50kW	513.88/kWh 10kW/20kWh	None Commercial systems with high self-consumption rate avoiding exports to the grid to avoid grid connections costs
TOU	Residential (4.046 kWh/year load)	Price decline scenario: 2021: TOU tariff profiles in Figure 57 & Figure 58 2025: TOU Rate x 0.72 (discounting daytime prices more than other hours)	Base case	Base case size 2021: $1.4/W 2025: $1.2/W 2030: $1.1/W 2040: $0.8/W	Base case size 2021: $642/kWh 2025: $496/kWh 2030: $393/kWh 2040: $302/kWh	Same as base case

	Commercial (350,000 kWh/year): Large Office	2030: 2025 TOU Rate x 1.0 2040: 2025 TOU Rate x 1.0 Constant price scenario: base case TOU tariff all years	Base case	Base case size 2021: $1.0/W 2025: $0.9/W 2030: $0.7/W 2040: $0.6/W	Base case size 2021: 513.88/kWh 2025: $396/kWh 2030: $314/kWh 2040: $242/kWh	Same as base case

A.3. New Jersey

Table 6: Assumptions used in New Jersey analysis

Modelled case / sensitivity	Load	Retail rate	Export rate	Solar system assumptions	Storage system assumptions	Other revenues or support
Base case	Residential (8,000 kWh/year)	Variable: $0.17/kWh	100% of the retail rate	$2.9/W; 7kW	$656/kWh; 5kW/14kWh	Retail net metering; federal tax credits, production-based incentive $85/MWh
	Commercial (114,000 kWh/year)	Variable: $0.08/kWh Demand charge: $19.36/kW	100% of the retail rate	$1.5/W; 100kW	$525/kWh; 50kW/100kWh	Retail net metering; federal tax credits, production-based incentive $85/MWh
No production-based incentive	Residential (8,000 kWh/year)	Variable: $0.17/kWh	100% of the retail rate	Base case	Base case	Retail net metering; federal tax credits
	Commercial (114,000kWh/year)	Variable: $0.08/kWh Demand charge: $19.36/kW	100% of the retail rate	Base case	Base case	Federal tax credits
Lower export rate (35%)	Residential (8,000 kWh/year)	Variable: $0.17/kWh	35% of the retail rate	Base case	Base case	35% net metering; federal tax credits, production-based incentive $85/MWh
	Commercial (114,000kWh/year)	Variable: $0.08/kWh Demand charge: $19.36/kW	35% of the retail rate	Base case	Base case	35% net metering; federal tax credits, production-based incentive $85/MWh
TOU low daytime rates	Residential (8,000 kWh/year)	Variable time-of-use Peak: 4-9PM $0.23/kWh, Off-peak: $0.13/kWh)	100% of the retail rate	Base case	Base case	Retail net metering; federal tax credits, production-based incentive $85/MWh
	Commercial (114,000kWh/year)	Variable time-of-use Peak: 4-9PM $0.15/kWh, Off-peak: $0.07/kWh) Demand charge: $19.36/kW	100% of the retail rate	Base case	Base case	Retail net metering; federal tax credits, production-based incentive $85/MWh

TOU high daytime rates	Residential (8,000 kWh/year)	Variable time-of-use Peak: 8AM-4PM $0.23/kWh, Off-peak: $0.15/kWh)	100% of the retail rate	Base case	Base case	Retail net metering; federal tax credits, production-based incentive $85/MWh
	Commercial (114,000kWh/year)	Variable time-of-use Peak: 8AM-6PM $0.16/kWh, Off-peak: $0.06/kWh) Demand charge: $19.36/kW	100% of the retail rate	Base case	Base case	Retail net metering; federal tax credits, production-based incentive $85/MWh
Aggregation payment ($/kW capacity)	Residential (8,000 kWh/year)	Variable: $0.17/kWh	100% of the retail rate	Base case	Base case	Retail net metering; federal tax credits, production-based incentive $85/MWh; $100/kW battery capacity/ year
	Commercial (114,000kWh/year)	Variable: $0.08/kWh Demand charge: $19.36/kW	100% of the retail rate	Base case	Base case	Retail net metering; federal tax credits, production-based incentive $85/MWh; $100/kW battery capacity/ year
BNEF Solution	Residential (8,000 kWh/year)	Variable: $0.17/kWh	35% of the retail rate	$2/W (lower than base case due to instant permits, labor incentives); 7kW	Base case	35% net metering; instant permits, labor incentives; federal tax credits, production-based incentive $85/MWh; $100/kW battery capacity/ year

Source: BloombergNEF

A.4. California

Table 7: Assumptions used in California analysis

Modelled case / sensitivity	Load	Retail rate	Export rate	Solar system assumptions	Storage system assumptions	Other revenues or support
Base case	Residential (12,000 kWh/year)	Time-of-use Peak: 4-9PM $0.41/kWh, Off-peak: $0.17/kWh)	100% of the retail rate	$2.8/W; 8kW	$656/kWh; 5kW/14kWh	Retail net metering; federal tax credits; rebates for storage
	Commercial (166,000kWh/year)	Time-of-use Peak: 4-9PM $0.36/kWh, Off-peak: $0.08/kWh) Demand charge: $22.77/kW	100% of the retail rate	$1.6/W; 100kW	$525/kWh; 50kW/100kWh	Retail net metering; federal tax credits; rebates for storage
New TOU utility proposal	Residential (12,000 kWh/year)	Peak: 4-9PM, $0.44/kWh	100% of the retail rate	Base case	Base case	Retail net metering; federal tax credits, rebates for storage

		Off-peak: 8PM-5PM, $0.16/kWh				
All-in new utility proposal	Residential (12,000 kWh/year)	Peak: 4-9PM, $0.44/kWh Off-peak: 8PM-5PM, $0.16/kWh	34% of the retail rate	Base case	Base case	34% net metering; solar charge $7.39/kW/month; federal tax credits, rebates for storage
TOU with lower export rate (35%)	Residential (12,000 kWh/year)	Time-of-use Peak: 4-9PM $0.41/kWh, Off-peak: $0.17/kWh)	35% of the retail rate	Base case	Base case	35% net metering; federal tax credits; rebates for storage
	Commercial (166,000kWh/year)	Time-of-use Peak: 4-9PM $0.36/kWh, Off-peak: $0.08/kWh) Demand charge: $22.77/kW	35% of the retail rate	Base case	Base case	35% net metering; federal tax credits, rebates for storage
Flat retail rate	Residential (12,000 kWh/year)	$0.25/kWh	100% of the retail rate	Base case	Base case	Retail net metering; federal tax credits, rebates for storage
	Commercial (166,000 kWh/year)	$0.13/kWh Demand charge: $22.77/kW	100% of the retail rate	Base case	Base case	Retail net metering; federal tax credits, rebates for storage
Wholesale TOU daytime	Residential (12,000 kWh/year)	Time-of-use Peak: 4-9PM $0.44/kWh, Off-peak: $0.01/kWh)	100% of the retail rate	Base case	Base case	Retail net metering; federal tax credits, rebates for storage
	Commercial (166,000 kWh/year)	Time-of-use Peak: 4-9PM $0.40/kWh, Off-peak: $0.01/kWh) Demand charge: $22.77/kW	100% of the retail rate	Base case	Base case	Retail net metering; federal tax credits, rebates for storage
Aggregation payment ($/kW capacity)	Residential (12,000 kWh/year)	Time-of-use Peak: 4-9PM $0.41/kWh, Off-peak: $0.17/kWh)	100% of the retail rate	Base case	Base case	Retail net metering; federal tax credits, rebates for storage, $100/kW battery capacity/ year
	Commercial (166,000 kWh/year)	Time-of-use Peak: 4-9PM $0.36/kWh, Off-peak: $0.08/kWh) Demand charge: $22.77/kW	100% of the retail rate	Base case	Base case	Retail net metering; federal tax credits, rebates for storage, $100/kW battery capacity/ year
BNEF Solution	Residential (12,000 kWh/year)	Time-of-use Peak: 4-9PM $0.41/kWh, Off-peak: $0.17/kWh)	35% of the retail rate	$2.2/W (lower than base case due to instant permits, labor incentives); 8kW	Base case	35% net metering; instant permits, labor incentives; federal tax credits, rebates for storage, $100/kW battery capacity/ year

New construction – reduced soft costs	Residential (12,000 kWh/year)	Base case	Base case	$1.6/W	N/A	Base case
	Commercial (166,000 kWh/year)	Base case	Base case	$1.0/W	N/A	Base case

Source: BloombergNEF

A.5. Australia

Table 8: Assumptions used in Australia analysis

Modelled case / sensitivity	Load	Retail rate	Export rate	Solar system assumptions	Storage system assumptions	Other revenues or support
Base case	Residential (6,220 kWh/year load)	Variable: A$0.34/kWh ($0.26/kWh)	A$0.12/kWh ($0.09/kWh)	A$1.1/W ($0.8/W); 6kW	A$874/kWh ($655/kWh); 4.3kW/12kWh	Federal solar rebate: A$532/kW State storage rebate: A$698/kW ($524/kWh) Storage aggregation payment: A$65/kW/year ($49/kW/year)
	Industrial (1GWh/year load) • Warehouse • Manufacturer • Office	Variable peak: A$0.12/kWh ($0.09/kWh) Shoulder: A$0.05/kWh ($0.04/kWh) Off-peak A$0.03/kWh ($0.02/kWh) (Peak times vary depending on month) Demand charge: A$12/kW/month ($9/kW/month)	Exports are curtailed	A$1/W ($0.8/W) 300kW for solar-only and 600kW for solar-plus-storage	A$699/kWh ($524/kWh) 250kW/500kWh	Federal solar renewable energy certificates: A$0.03/kWh ($0.02/kWh) in 2021, trending to zero by 2024 Storage aggregation payment: A$65/kW/year ($49/kW/year)
Low export rate	Residential (6,220 kWh/year load)	Variable: A$0.34/kWh	A$0.09/kWh (25% lower than base case)	A$1.1/W 6kW	A$874/kWh 4.3kW/12kWh	Federal solar rebate: A$532/kW State storage rebate: A$698/kW Storage aggregation payment: A$65/kW/year
Zero export rate	Residential (6,220 kWh/year load)	Variable: A$0.34/kWh	No export payment	A$1.1/W 6kW	A$874/kWh 4.3kW/12kWh	Federal solar rebate: A$532/kW State storage rebate: A$698/kW Storage aggregation payment: A$65/kW/year

TOU	Residential (6,220 kWh/year load)	Variable peak: 6-10AM & 3PM-1AM, A$0.38/kWh Shoulder: 1-6AM, A$0.24/kWh Off-peak: 10AM-3PM, A$0.18/kWh	A$0.12/kWh	A$1.1/W 6kW	A$874/kWh 4.3kW/12kWh	Federal solar rebate: A$532/kW State storage rebate: A$698/kW Storage aggregation payment: A$65/kW/year
TOU, extended off-peak	Residential (6,220 kWh/year load)	Variable peak: 6-8AM & 5PM-1AM, A$0.38/kWh Shoulder: 1-6AM, A$0.24/kWh Off-peak: 8AM-5PM, A$0.18/kWh	A$0.12/kWh	A$1.1/W 6kW	A$874/kWh 4.3kW/12kWh	Federal solar rebate: A$532/kW State storage rebate: A$698/kW Storage aggregation payment: A$65/kW/year
TOU, divergent peaks	Residential (6,220 kWh/year load)	Variable peak: 6-10AM & 3PM-1AM, A$0.58/kWh Shoulder: 1-6AM, A$0.24/kWh Off-peak: 10AM-3PM, A$0.06/kWh	A$0.12/kWh	A$1.1/W 6kW	A$874/kWh 4.3kW/12kWh	Federal solar rebate: A$532/kW State storage rebate: A$698/kW Storage aggregation payment: A$65/kW/year
TOU, w TOU export	Residential (6,220 kWh/year load)	Variable peak: 6-10AM & 3PM-1AM, A$0.38/kWh Shoulder: 1-6AM, A$0.24/kWh Off-peak: 10AM-3PM, A$0.18/kWh	50% of retail rate	A$1.1/W 6kW	A$874/kWh 4.3kW/12kWh	Federal solar rebate: A$532/kW State storage rebate: A$698/kW Storage aggregation payment: A$65/kW/year
Higher aggregation	Residential (6,220 kWh/year load)	Variable: A$0.34/kWh	A$0.12/kWh	A$1.1/W 6kW	A$874/kWh 4.3kW/12kWh	Federal solar rebate: A$532/kW State storage rebate: A$698/kW Storage aggregation payment: A$140/kW/year (115% higher than base)
Zero aggregation	Residential (6,220 kWh/year load)	Variable: A$0.34/kWh	A$0.12/kWh	A$1.1/W 6kW	A$874/kWh 4.3kW/12kWh	Federal solar rebate: A$532/kW State storage rebate: A$698/kW
Higher demand charges	Industrial (1GWh/year load) • Warehouse • Manufacturer • Office	Variable peak: A$0.12/kWh Shoulder: A$0.05/kWh Off-peak A$0.03/kWh	Exports are curtailed	A$1/W 300kW for solar-only and 600kW for solar-plus-storage	A$699/kWh 250kW/500kWh	Federal solar renewable energy certificates: A$0.03/kWh in 2021, trending to zero by 2024

	(Peak times vary depending on month) Demand charge: A$18/kW/month (50% higher than base case)		Storage aggregation payment: A$65/kW/year

Source: BloombergNEF. Note: We have modelled residential for South Australia; industrial for New South Wales.

A.6. Rates assumptions

Table 9: Rate assumptions

	Inflation rate	Cost of capital	
		Residential	**Commercial and industrial**
France	1.5%	6%	2%
Spain	1.5%	7%	3%
New Jersey	2.4%	4%	7%
California	2.4%	4%	7%
Australia	2.0%	5%	6%

Source: BloombergNEF

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