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De-Risking Utility-Scale Solar

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Abstract

While the components of utility-scale photovoltaic (PV) power stations are moving rapidly down their respective cost curves, the investment context for such plants is generally still untenable in most electricity markets. While part of the challenge lies in electricity market arrangements that do not appropriately price the environmental impacts of fossil fuel generation, another difficulty is that operators of utility-scale PV generators are unable to appropriately de-risk the value of output from their highly variable and somewhat unpredictable power plants. Securing financing for prospective utility-scale PV projects is challenging, in part, due to a lack of available strategies to mitigate revenue risk in restructured electricity markets.

Currently available energy market derivatives - including swaps and options - are intended to mitigate revenue risks for base load and dispatchable peaking generators, as well as counterpart retailers and large industrial loads. This paper examines whether unconventional contracting strategies might be used to de-risk utility-scale PV plants and provide financial products that are appropriate to these plants yet still attractive to retailers. Additionally, it investigates the benefits of adding a dispatchable energy storage component to take advantage of market movements.

Historical weather and market data were used to model the output of PV plants at several sites across Australia as a base scenario. Market simulations were then run with a number of different contract portfolios, also derived in part from historical values, to determine the viability of conventional and unconventional financial hedges as de-risking strategies for utility-scale PV. Further simulations were run using battery storage as a physical hedge and a combination of battery and contractual hedges.

From an analysis of the Australian National Electricity Market (NEM), it was found that PV plant operators are particularly exposed to extreme fluctuations in the electricity spot price. Using market-only simulations, it was found that a customised shaped cap option mitigated the majority of market risk for a PV plant operator, while providing revenue above the required targets while still providing a useful hedge for retailers.

Simulations of PV systems with battery storage were found to be more profitable than other strategies due to the large price peaks in the NEM, but were not useful in mitigating the majority of the market risk experienced by plant operators. A combined strategy featuring both financial hedges and batteries was found to be the most effective strategy, minimising market risk and bringing plant revenues above the required targets. These findings would

seem to highlight the importance of appropriate financial derivative innovations in helping facilitate future utility scale PV deployment.

1. Introduction

The PV industry has made great progress in the last decade, with over 3.5GW of installed capacity in Australia, meeting an estimated 1.3% of national electricity demand in 2013. All major cost components are now travelling rapidly down their respective learning curves. PV module prices in Australia halved to 0.75c/W from 2012 to 2013 and installed prices for residential systems dropped from $3/W to $2.50/W over the same period, making PV a cost effective alternative to grid-derived electricity in the residential market and increasing interest in the commercial sector. At the utility-scale however, PV generators are still reliant upon government support. In part this is a reflection of market distortions that do not require conventional fossil-fuelled generators to fully pay externality costs associated with their generation, such as regional air-pollutants and climate change damages. Furthermore, existing, primarily fossil-fuelled, generation are sunk investments and often enjoy favourable fuel contracts and incumbent regulatory advantages. This poses additional challenges for policy makers seeking to transition the electricity industry towards a cleaner energy future. However, utility-scale PV (and other intermittent renewable energy technologies such as wind) faces further challenges in operating plants with highly variable and somewhat unpredictable generation within a wholesale market where electricity is priced according to a changing supply-demand balance.

Existing market arrangements, such as derivatives, help conventional dispatchable generators manage revenue risks by providing sources of compensation to mitigate losses and strategies for locking in revenue upfront for traditional generation technologies. These arrangements are less suitable for PV operators as they commit the contracting party to the supply of future volume, which, for PV generators, cannot be guaranteed. Government support, including the Australian Renewable Energy Target (RET) tradable certificate scheme, has facilitated the installation of several utility-scale PV plants in Australia, including a 10MW plant at Greenough River in WA, a 20MW system in the ACT (under its reverse-auction feed in tariff program) and a 50MW system in NSW, funded by the Australian Government's Solar Flagships program. Reliance on such support, however, exposes prospective PV generators in Australia to high levels of sovereign risk – for instance, any changes to the RET (which is currently under review), will alter the revenue for existing or planned utility-scale PV power plants. This highlights the need for a range of strategies to manage market risk and boost profits for PV generators, away from government-led initiatives. Even with government subsidies, such as through the Solar Flagships program, developers of PV power plants have struggled to sign Power Purchase Agreements (PPAs), without which they would be exposed to spot prices. This increased revenue risk has reduced the attractiveness of utility-scale PV investment for financiers, and has been a factor in the failure of utility-scale projects to proceed to construction.

This study of the potential for contracting strategies and energy storage to be used to de-risk utility-scale PV plants comprises four sections. To gain an understanding of the basic economics of utility-scale PV in the near-term (3-5 years), a review of pricing data was undertaken, and the results used to calculate a range of values for the levelised cost of electricity (LCOE) for PV developments. The LCOE was later used as a revenue threshold, above which the earnings of a plant were deemed to be profitable.

In order to ascertain the suitability of unconventional de-risking options, simulated PV output was compared to price data from the Australian National Electricity Market pools of NSW, SA, VIC and QLD, in order to identify opportunities for financial hedging strategies. We conducted an evaluation of commonly available hedging contracts on the Australian Stock Exchange, as well as developing a custom over-the-counter contract for use by PV operators. Also examined was the concept of using energy storage systems as a physical hedging strategy. Current pricing and performance metrics for four battery types were investigated and simple battery performance simulations were developed for each type. These models were used as inputs for a perfect-foresight unit commitment algorithm based on dynamic programming principles.

Finally, a study was undertaken into the financial benefits of combining energy storage and contractual hedging strategies. The unit commitment algorithm was extended to incorporate the constraints of financial derivatives, and several contractual scenarios were modeled against the model of a PV plant with energy storage.

2. Economics of Utility-Scale PV

A near-term estimate of overall system cost was reached by conducting a review of available component price data. The major costs of utility-scale PV developments were broken into four broad categories for comparison, comprising of module, inverter, balance-of-system (BOS) (including installation) and operating costs. This analysis was performed for both fixed and single-axis tracking PV systems, with the results shown below in Table 2.1.

Table 2.1 Component Costs of Utility-Scale PV

Component	Lowest Cost	Source (Lowest)	Highest Cost	Source (Highest)
Module	$0.39 (2014 AUD $/W)	Mehta et al. 2013 p. 4	$1.10 (2014 AUD $/W)	AETA 2012, p. 43
Inverter	$0.15 (2014 AUD $/W)	GTM Research 2013, p. 4	$0.15 (2014 AUD $/W)	GTM Research 2013, p. 4
BOS (Fixed)	$1.20 (2014 AUD $/W)	AETA 2012, p. 43	$1.20 (2014 AUD $/W)	AETA 2012, p. 43
BOS (Tracking)	$1.48 (2014 AUD $/W)	AETA 2012, p. 43 + Barbose 2012 p. 3	$1.70 (2014 AUD $/W)	AETA 2012, p. 43 + AETA 2012, p. 44
O & M (Fixed)	$25,000 (2014 AUD $/MW/year)	AETA Update 2013 p. 25	$25,000 (2014 AUD $/MW/year)	AETA Update 2013 p. 25
O & M (Tracking	$30,000 (2014 AUD $/MW/year)	AETA Update 2013 p. 25	$30,000 (2014 AUD $/MW/year)	AETA Update 2013 p. 25

The costings in Table 2.1 were combined with estimated PV plant output at various average levels of incident insolation, to estimate the LCOE from a utility-scale PV development. The insolation was derated by 85% to account for average plant efficiency (Stapleton et al. 2010) and the costs were discounted over an assumed 20-year plant operating period. Further assumptions in this model included a 2.7% inflation rate (RBA Online Calculator, 2014), a 10% discount rate (calculated from a required real rate of return of 7%) and a corporate tax rate of 30%. The results of this analysis are shown below in Table 2.2.

Table 2.2 Levelised Cost of Electricity Estimates

Incident kWh/sq.m/Day	Fixed Low LCOE	Fixed High LCOE	Tracking Low LCOE	Tracking High LCOE
5	$101.11 (2014 AUD $/MWh)	$137.28 (2014 AUD $/MWh)	$117.90 (2014 AUD $/MWh)	$164.85 (2014 AUD $/MWh)
6	$84.26 (2014 AUD $/MWh)	$114.40 (2014 AUD $/MWh)	$98.25 (2014 AUD $/MWh)	$137.38 (2014 AUD $/MWh)
7	$72.22 (2014 AUD $/MWh)	$98.06 (2014 AUD $/MWh)	$84.21 (2014 AUD $/MWh)	$117.75 (2014 AUD $/MWh)

The calculated LCOE estimates shown in Table 2.2 were within the range of estimates found in other sources, notably Reichelstein et al. (2012) and AETA (BREE 2012). These LCOE estimates established clear thresholds above which the revenue of a plant is expected to be profitable.

3. Correlation Between PV Output and the Electricity Spot Market

To gain an understanding of the relationships between PV output and NEM spot market prices, solar insolation records (BOM 2012), cosine loss tables (Sunapse 2014) and market price datasets (AEMO 2014) were correlated. It was found that there is some correlation between times of high theoretical PV output and times of high market prices. This suggested that PV generators could be able to take advantage of peak price events and that there may be some scope for PV operators to offer financial products that could minimise the risk of price-exposed demand-side players at these times.

A utility-scale PV power plant of arbitrary size was simulated based on the merchant model, whereby the generator accepts the spot market price for their electricity at the time of generation. It was found that such plants rely on two effectively separate streams of revenue. One stream comes from the everyday price fluctuations in the electricity market, whereby the wholesale electricity price fluctuates between $40-$80/MWh in general. The second stream is from ‘peak’ price events, whereby a supply shortfall causes the price to spike close to the market cap of $12,900/MWh. These ‘peak’ events are rare (<0.5% of all movements) and relatively unpredictable, though there are some time periods and seasons in which they are more frequent. PV generators are found to be profitable only when they are allowed to take advantage of both components. This means that there is no way to finance a utility-scale PV plant without relying on these high price events, which are not guaranteed over any given generation period, but which can be expected over the long-term.

An analysis was run to determine whether the currently available financial products on the Australian Stock Exchange - the base load swap, the peak load swap and the $300 cap, are suitable for PV. This was done by using a python program to estimate earnings and losses based on time series insolation and market data, with the additional constraints of each contract. Base and peak load swaps effectively lock in an averaged electricity price for both the generator and the retailer, whereby the parties, which have countervailing risk, compensate each other for market fluctuations. The $300 cap option, which is a class of financial derivatives commonly traded between electricity market participants on the ASX Energy markets, obligates the generator to compensate the retailer when the price of electricity exceeds $300/MWh. This contract allows plant operators to lock in revenue upfront through the sale of the contract. From the PV and market simulations, it was found that the baseload and peakload swaps exposed the PV generator to more losses than were financially sustainable, bringing plant revenues below the thresholds previously calculated, meaning that revenues were not high enough to be considered profitable. The $300 cap was found to be profitable, as it brought plant revenue over the LCOE thresholds in some locations.

This initial price and plant output analysis revealed that while $300 cap contracts can help plants lock in revenue upfront, they face additional risk during non-daylight hours when they are obliged to compensate retailers during peak price events, without any generation capacity to recoup losses. Additionally, electricity retailers are assumed to be facing exposure during these daytime peak pricing events due to extreme fluctuations in demand over these periods. This means it is likely that a portion of their high-demand portfolio is at the very least exposed to a $300 strike price, which is well above average expected energy prices. The hypothesis was raised that it may serve energy retailers’ financial interests to sign a contract that reduces their market risk during these daytime peak price events, where they may be under-hedged. Any such financial products must first satisfy two criteria:

1. Reduce market risk for the PV plant by locking in the necessary peak-price revenue upfront.
2. Have benefits for retailers that are greater than those offered by publicly available products.

A shaped cap option was proposed, whereby the PV generator would agree to compensate a retailer for losses incurred during high-price events, during standard PV output hours 7am - 4pm. In return, the retailer would pay a set fee upfront for the contract. A market and demand data analysis found that market price events over $100/MWh correlate with times of above-average demand, suggesting that retailers are likely to be unhedged to some degree when generation is most profitable.

The value offered to a retailer by the shaped cap option is expected to lie in a given range depending on whether the retailer is unhedged or has a portfolio containing $300 caps. Both of these scenarios were modelled to obtain a range of valuations for the shaped cap option. The modelling was performed by examining the spread between a prospective strike price and either the $300 cap or the spot price, using historical market data from 2005 - 2011. This established a threshold range of potentially viable prices for which a generator could offer a shaped cap. The results of these analyses are shown in Table 3.1.

A further analysis was carried out to determine the proportion of a plant's nameplate capacity that can safely be contracted. This was achieved by calculating the effective plant capacity factor during contracting hours (7am - 4pm) using historical insolation data from a series of locations in different states. It was found that effective capacity factor ranged from 0.28 - 0.32 for fixed systems and 0.32 - 0.39 for tracking systems.

Also considered was the extent to which a PV generator is able to meet demand during price events above the contracted strike price. It was assumed that the plant was contracted up to the effective capacity factor. Using historical insolation and market data (2005 - 2011) it was found that the probability of a PV generator meeting the required generation capacity during these times is in the range 0.5 - 0.7. Because these probabilities suggest that the generator may not meet the required output at some times, we incorporate a risk premium into the pricing of the shaped cap contract.

We propose that the shaped cap contract be priced as follows:

Average Payout = Average loss to generator when spot price > strike price
Strike Probability = Probability that spot price > strike price in daylight hours
N = number of time periods in contract
Generation Probability = Probability that PV plant is generating when spot price > strike price in daylight hours
Price of Option = (*Average Payout* * *Strike Probability* / *Generation Probability*) * *N*

Using this method, contracts were priced for tracking and non-tracking PV systems in each state. In all cases the option prices were between the value-at-risk and the intrinsic value, which is the theoretically acceptable range of values from the perspective of a retailer. This means that such a contract could be feasibly negotiated. These results are also shown in Table 3.1.

A plant output simulation was used to determine the revenue of a PV plant with a shaped cap, contracted up to the effective capacity factor. It was found that in nearly all cases the revenue from such a plant was above the low-range LCOE threshold required for plant profitability. In

South Australia, revenues exceeded even the conservative high-range LCOE estimates due to higher average spot prices than other states. It was thus found that by using a shaped cap option, utility-scale PV plants can take advantage of the necessary peak price events, mitigating market risk by locking in this revenue upfront.

Table 3.1. Value-at-risk and intrinsic value of shaped cap contracts

Strike Price ($/MWh)	Monthly Value-At-Risk $/MW (hedged with $300 cap)	Monthly Intrinsic Value $/MW (Unhedged)	Shaped Cap Monthly Prices Value $/MW (Fixed)	Shaped Cap Monthly Prices Value $/MW (Tracking)
$100	$800 (NSW) $790 (SA) $720 (QLD) $590 (VIC)	$4820 (NSW) $6550 (SA) $3940 (QLD) $3160 (VIC)	$2390 (NSW) $3440 (SA) $1840 (QLD) $1640 (VIC)	$2820 (NSW) $4220 (SA) $2090 (QLD) $2030 (VIC)
$150	$490 (NSW) $460 (SA) $430 (QLD) $340 (VIC)	$4520 (NSW) $6230 (SA) $3630 (QLD) $2920 (VIC)	$2200 (NSW) $3060 (SA) $1700 (QLD) $1450 (VIC)	$2570 (NSW) $3740 (SA) $1910 (QLD) $1810 (VIC)
$200	$280 (NSW) $260 (SA) $240 (QLD) $190 (VIC)	$4330 (NSW) $6050 (SA) $3440 (QLD) $2790 (VIC)	$2080 (NSW) $2890 (SA) $1650 (QLD) $1270 (VIC)	$2410 (NSW) $3530 (SA) $1840 (QLD) $1590 (VIC)
$250	$120 (NSW) $110 (SA) $100 (QLD) $80 (VIC)	$4180 (NSW) $5910 (SA) $3300 (QLD) $2690 (VIC)	$2020 (NSW) $2780 (SA) $1590 (QLD) $1110 (VIC)	$2320 (NSW) $3380 (SA) $1760 (QLD) $1370 (VIC)

4. Energy Storage

The shaped cap contracting strategy solves the problem of mitigating market risk for PV plant operators in the near-term, based on the assumption that the correlation between PV plant output and high prices will remain strong. While this assumption may hold true in the near-term, over a 20-30 year financing period such an assumption is not valid (for example, as PV deployment continues to grow), meaning that plant operators could be left with an unsustainable shortfall in revenue as short-term derivative contracts become less valuable. This risk is inherent in conventional non-dispatchable renewable energy systems. We investigate the feasibility of constructing a dispatchable PV power plant, using batteries as an energy storage system or 'physical hedge,' in order to take advantage of general trends in the electricity spot price that fall outside of the PV production window, such as higher mid-evening loads. A review was conducted to gain an understanding of the near-term pricing and operating characteristics of different battery technologies, namely lead acid (Pb-A), lithium ion (Li-Ion), sodium sulfur (Na-S) and vanadium redox (VRB) batteries. The results are shown in Table 4.1.

Table 4.1 Characteristics of Battery Types

Battery Type	Self-Discharge Per Day	Cycle Efficiency	Max Cycles	Max DOD	Cost 2013 AUD $/ kWh
Pb-A	0.5%	90%	1800	80%	$220
Li-Ion	0.1 – 0.3%	100%	3000	80%	$502
Na-S	20%	90%	6500	65%	$385
VRB	Negligible	85%	12000	100%	$165
Ideal	0	100%	Unlimited	100%	$0

Using core battery characteristics such as self-discharge fraction per day, cycle efficiency, maximum lifetime cycles, maximum depth of discharge and capital cost per kWh, a simple model of battery performance was developed. Storage was broken into a number of discrete levels and any transition between storage levels was subject to the losses described. This model was then used as an input into a backward-looking dynamic programming algorithm, which calculated the mathematically optimal market dispatch strategy for a PV array with a battery storage system. Similar algorithms are commonly used to solve perfect foresight unit dispatch problems, primarily in hydroelectric generation systems. This algorithm is shown in Figure 4.1.

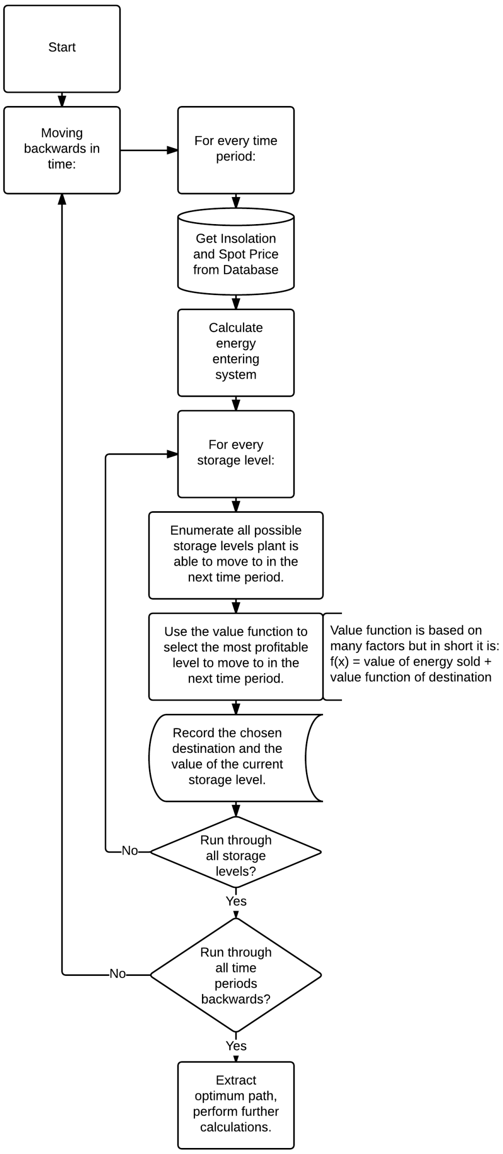

Figure 4.1. High-level Dynamic Programming Algorithm Flow Chart

The algorithm runs with perfect market foresight, thus providing an estimate of the theoretical maximum revenue that can be earned from a PV system with battery storage. A python implementation of this algorithm was run using market and insolation data from 2005 - 2011.

The primary hypothesis was that by using battery storage, PV plants could take advantage of higher afternoon and late-evening prices in the electricity market and make enough revenue to avoid reliance on outlier 'peak' price events. The algorithm was run using irradiance (BOM 2012) and market (AEMO 2014) data from 2005 – 2011, on VRB, Li-Ion, Na-S and Pb-A batteries, as well as an 'ideal' battery with 100% efficiencies and zero operational or capital costs. Plants with 1- 4 MWh of storage per MW of nameplate capacity were modeled.

It was found that only plants with an 'ideal' battery bank and at least 2 MWh/MW nameplate of storage were able to earn enough revenue to surpass the required LCOE thresholds. Thus, the hypothesis that batteries can alleviate market risk by taking advantage of standard price fluctuations was proven correct. The battery technologies tested were, however, found to be too expensive to attempt such a strategy in a real-world setting as the additional revenue was not sufficient to pay back the capital cost of the systems. Thus the overall finding is that the primary market risk experienced by PV generators cannot be alleviated by using batteries at their current and near-term price levels.

A further analysis was performed to determine whether batteries could enhance profitability for a PV plant under the contract-free merchant model. It was found that when 'peak' prices were included in the market dataset they presented a perverse incentive that forced the algorithm to save electricity for long periods in an unrealistic way. To avoid this problem, variations between consecutive prices were capped at 10 %. Using this smoothed dataset, a more reasonable dispatch path was determined, and this path was then used on an unaltered dataset to estimate revenues from the merchant model.

It was found that using this strategy, all battery types were able to produce enough additional revenue, such that both the low and high LCOE thresholds were exceeded. Batteries were thus found to increase the overall profitability of the plant, although they were not found to reduce market risk on their own because they did not address the core problem of reliance on peak price events for plant profitability.

5. Energy Storage and Contractual Hedges

A final analysis was conducted whereby the constraints of commonly available futures contracts in the NEM were incorporated into the PV-battery dispatch algorithm. From these simulations it was determined that base load swaps, peak load swaps and $300 caps are financially profitable with all simulated PV-battery systems with 2 and 3 MWh/MW battery nameplate capacity. It is however considered unlikely that base and peak load swaps will solve any problems for PV plants as they still do not allow the generator to lock in 'peak' price event revenue.

The $300 cap, however, solves significant problems for the PV generator by locking in the required 'peak' spot market revenue upfront. A dispatch strategy was modelled based on perfect foresight of smoothed market price movements to reduce any price signals that would lead to the algorithm generating unconventional solutions. It was seen that in the long run, revenues coincided with peak price movements, negating serious losses, and that revenues were above key profitability thresholds. We thus conclude that the $300 cap option is a viable solution to the problem of reducing market risk for PV generators with battery banks. We find that the most profitable hedging strategy for a utility-scale PV plant is to use VRB batteries with 2 - 3 MWh of storage, financially hedging up to the plant's effective capacity factor with a $300 cap.

6. Conclusion

We conclude that 'shaped caps' provide a potentially realistic and profitable approach to risk management for utility-scale PV generators in the Australian NEM. It was found that batteries by themselves are capable of significantly increasing revenue, but that they do not inherently decrease market risk. In an analysis of combinations of physical and financial hedges, it was found that batteries used in conjunction with publicly available $300 caps lock in enough revenue to provide both risk management and increased revenue. This scenario would seem to offer a useful strategy for both increasing profits and decreasing risk for utility-scale PV power plants in the Australian NEM.

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