Sizing and grid impact of PV battery systems - a comparative analysis for Australia and Germany

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***Abstract*—As the business case for home-scale PV battery systems emerges in Australia and Germany, the impact of different pricing schemes and grid integration approaches on the sizing and operation of such systems and on distribution grids has to be evaluated. This paper proposes an integrated approach which first derives optimally configured PV and battery systems using a mixed integer linear program and subsequently assesses their impact on grid planning aspects such as peak feed-in and peak load for an Australian and a German case study. The results show that small scale PV battery systems will be an economically viable option in the near future in Australia. A reduction in peak load is achievable in the presented example as well. In Germany, stand-alone PV systems will provide the economically more favorable option under current battery prices. For lower battery prices a high increase in installation rates can be expected. Depending on the control strategy, battery systems are able to significantly reduce PV peaks in Germany. For distribution grid operators estimations on the average peak reduction per installed PV battery are presented.**

I. Introduction

Australia and Germany are two of the largest markets for rooftop photovoltaic (PV) systems which are currently undergoing a transformation of existing PV business models. As many Australian states have abandoned PV feed-in tariff (FIT) schemes, PV systems are more sized to maximize the local PV consumption and to minimize PV grid feed-in nowadays [1]. In Germany, this so called PV self-consumption has gained importance since FIT rates dropped below electricity prices for households in 2012. Hence, the business case for rooftop PV systems depends more and more on the amount of achievable PV self-consumption [2], [3]. These systems are mainly connected to the low voltage (LV) level of the distribution grid. Grid integration challenges such as PV feed-in related voltage rises or reverse power flows over the transformer have put the focus on LV grid planning and operation practices. Now, such systems are encouraged to actively provide ancillary services to the grid [4], [5], [6], [7].

Changing economic conditions and grid requirements have paved the way for small scale storage systems such as battery systems. Storage systems have the ability to offer an additional degree of freedom for energy and power management to mitigate PV and demand related power peaks, facilitate PV grid integration and potentially defer grid reinforcements [8], [9], [10]. Yet, the relationship between economically optimal sizes of PV battery systems and their impact on PV grid integration has not been sufficiently investigated. Hence, this paper provides an approach which allows integrating the sizing and operation decision of PV and PV battery systems in one optimization problem and assessing their impact on key indicators of grid planning and operation. Sizing and grid impact results are discussed based on an Australian and a German case study.

II. Sizing of PV battery systems

This section provides a market and literature review on assumptions and approaches for sizing PV battery systems. Afterwards, an approach developed at Fraunhofer IWES for solving the investment and operation decision, using a mixed integer linear programming formulation, is presented. Based on the data retrieved from the market review, two case studies are conducted.

A. Market and literature review

The market for small scale PV battery systems has continuously grown over the last couple of years. Main drivers behind these developments have been cut-backs in PV FIT and increasing electricity prices in Australia and Germany. Furthermore, the supplier side has evolved over the last years, e.g. over 40 different system sellers offer close to 300 different systems nowadays in Germany [11]. Increasing competition, an investment incentive program for PV battery systems and economies of scale have led to a price drop of 25 % for lead-acid and lithium-ion based battery systems over the last year in Germany [12]. The Australian market for PV battery systems is picking up pace as time-of-use (TOU) tariffs create additional incentives for active load management using storage systems [1], [13].

Studies and research on PV battery sizing are often based on generic storage models. Simple charging and discharging control strategies are implemented. The battery is charged when the PV output is higher than the current load demand until it is fully charged. It is discharged when load demand exceeds current PV generation until the battery reaches its lower limit. Often standard load profiles for households and hourly PV data are used as input data [14], [15] which results in overestimating potential self-consumption. Further analyses use detailed component models, measured PV and household profiles with a high time resolution which allows

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for a more accurate analysis of the different power flows [2], [3], [16], [17]. Optimal storage sizes are determined by simulating different PV battery combinations and determining the maximum net present value (NPV) in a post analysis. Such approaches tend to lack the flexibility to adapt new constraints which influence the implemented control strategies. Furthermore, they do not model the interaction between changing prices and the optimal size as they assume a fixed size for the given control strategy. Using convex and/or mixed integer linear programming approaches can provide a solution to address the described issues. Non-convex and nonlinear programming approaches might provide an optimal solution (and arguably a better one if nonlinearities in components are significant) as well [18]. Yet, they increase the numerical complexity and the computation time. As a convex and/or MILP programming approach leads to provable optimality with manageable numerical complexity, such an approach is chosen.

B. Optimal sizing approach

To identify the impact of different input prices and technical parameters directly, the investment and operation decision is formulated as a mixed integer linear programming problem. Such approaches have been used in similar contexts for investment decisions into distributed energy resources (DER) [19], [20], yet not in the context of PV self-consumption and grid integration. Hence, the presented model allows including specifics of the self-consumption business case in the optimization problem. The model is able to determine optimal DER sizes for a given household load profile (measured and in high time-resolution), certain price data including price forecasts and linearized technical component characteristics [21]. It is implemented in Python using the algebraic modeling language Pyomo [22], [23].

1) Objective function: Its overall objective is to minimize the local electricity cost for one household while taking into account the possibility of investing into a PV system, a battery system or a combined PV battery system. Hence, decision variables are component sizes and electricity flows. The following sizes $Size_{Set}$ are included: PV system size $Size_{PV}$, battery capacity $Size_{BatCap}$ and battery inverter size $Size_{BatInv}$. To describe the operation problem, the following electricity flows E_{Set} are modeled as decision variables:

- Load supplied through the grid: $E_{Grid2Load}$
- PV related energy flows: PV grid feed-in $E_{PV2Grid}$, direct PV self-consumption $E_{PV2Load}$, PV curtailment due to regulatory requirements E_{PVcurt}
- Battery related energy flows: PV battery charging E_{PV2Bat}, battery charging from the grid $E_{Grid2Bat}$, battery discharging to load $E_{Bat2Load}$; battery discharging to the grid is not included as there is no incentive to act accordingly.

All cost relevant decision variables are incorporated in the objective function:

$$min(Invest + FixCostY + VarCF) \tag{1}$$

Here, total investment cost $Invest$ are calculated by the summation of the component related investment cost which are products of size and cost per unit $InvestCost$, e.g. EUR per installed kWp of PV:

$$Invest = \sum_{I \in Size_{Set}} InvestCost_I \cdot Size_I \tag{2}$$

Yearly fixed costs $FixCostY$ such as yearly PV maintenance cost or fixed grid connection fees are included as well. Furthermore, energy flow related costs and revenues $VarCF$ are comprised, e.g. a FIT for $E_{PV2Grid}$ and electricity household prices for $E_{Grid2Load}$ and $E_{Grid2Bat}$. The yearly cash flows are discounted over the calculation period considering degradation and aging effects for different components and changing prices. Further details can be found in [21].

2) Constraints: An energy balance is ensured for each time step through the implementation of load and component specific equality constraints. For example, the given household load $Profil_{Load}$ is met through the following equation:

$$E_{Grid2Load}(t) + E_{PV2Load}(t) + E_{Bat2Load}(t) = Profil_{Load}(t) \quad \forall\, t \in Time \tag{3}$$

The time set $Time$ specifies simulation length and time step size, e.g. 1 year in 10 minute time steps. Further constraints such as the battery model can be found in [17], [21].

For the analysis of the German business case, a grid supporting system operation is introduced through an active power limitation Lim_{PV} for $E_{PV2Grid}$:

$$E_{PV2Grid}(t) \leq Lim_{PV} \cdot Size_{PV} \quad \forall\; t \in Time \tag{4}$$

Depending on the system configuration, this limit is set to 70 % if only a PV system is installed, or to 60 % if a PV battery system is installed with the investment incentive described above. This if-else-decision is linearized by introducing a binary variable to decide if the investment incentive is taken at the potential risk of facing higher PV curtailment due to a lower active power limit.

To cope with investor requirements such as a desired payback period $PaybackP$ for the initial investment costs $Invest$, the following constraint is introduced:

$$RefCost - FixCostY - VarCF \geq Invest \cdot PaybackP^{-1} \tag{5}$$

where the reference costs $RefCost$ are the yearly electricity cost without installed DER.

C. Case studies

Two case studies are conducted to investigate how component prices, tariff structures and grid requirements impact the investment decision and operation of PV battery systems in Australia and Germany.

1) Assumptions: Based on the market and literature review, Table I and Table II summarize the used input data for the proposed optimization. Further details can be found in [21].

The current average price for battery systems (incl. general sales tax, installation and power electronics) lies between 1,500 and 2,000 EUR/kWh for lithium-ion battery based systems [12]. With the model described above, these investment cost are split into capacity and inverter costs. The chosen price ranges indicate that low and high PV and battery prices are included in the analysis. A major difference between Australia and Germany is the expected lifetime of the batteries. It is assumed that Australian weather conditions allow for a battery lifetime of 10 years. Accordingly, replacement costs are included in the model. In Germany, however, many suppliers advertise their systems with a lifetime of 20 years. Required rate of returns (RRR) also vary as European interest rates are close to zero, and no high risk premium is expected due to the 20 year lasting FIT. For the Australian business case higher RRR are assumed. For both countries measured household load profiles with a time resolution of 10 minutes (Germany) and 30 minutes (Australia) and a yearly consumption between 3 to 10 MWh are selected. One measured, normalized PV profile from each location serves as PV input for all simulations.

TABLE I
KEY ASSUMPTIONS FOR INVESTMENT AND OPERATION OPTIMIZATION
[1], [11], [12], [24], [25], [26], [27], [28], [29]

Parameter		Unit	Australia (°=AUD)	Germany (°=EUR)
Tariffs	El. price	°/kWh	see Table II	0.27 (flat)
	Fixed el. cost	°/year	326	112
	El. price dev.	%/year	2.5 and 5.0	
	FIT	°/kWh	0.08	0.12
	FIT dev.	%/year	-2	0
PV	Invest.	°/kWp	1,300 and 1,600	
	Lifetime	years	20	
Battery	Cap. invest.	°/kWh	400 - 1,200 (Lithium-ion incl. BMS)	
	Inv. invest.	°/kVA	400 - 800	200 - 600
	Lifetime	years	10	20
	Cycles over lifetime	no.	5,000	
Profiles	Load	no.	70	120
	PV	Location	Newcastle	Kassel
	Time step	min.	30	10
Others	Calculation period	years	20	
	Payback period (PP)	years	10 and 20	
	Required rate of return (RRR)	%	4 - 6	2 - 4

TABLE II
TIME-OF-USE (TOU) TARIFF FOR AUSTRALIAN CASE STUDY [26]

Type	Time	Price (AUD/kWh)
Peak	2 pm - 8 pm, Monday - Friday (excl. public holidays)	0.51
Shoulder	7 am - 2 pm & 8 pm - 10 pm, Mon. - Fri., 7 am - 10 pm on weekends & holidays	0.20
Off-Peak	10 pm - 7 am, Monday - Sunday (incl. public holidays)	0.11

2) Sizing results: Figure 1 and Figure 2 display PV system sizes and installed battery capacities for one specific set of input parameters over all analyzed households (which are categorized according to their yearly load consumption). These rather low battery investment costs, low RRR and long payback expectations allow to point out some general similarities and differences for the business case for PV battery systems in Australia and Germany. As the German FIT is significantly higher than the Australian FIT, there is still an incentive to feed excess PV energy into the distribution system and install larger PV systems. While in Germany 1 kWp or more is installed per MWh of yearly load demand, in Australia this ratio is only 0.5 kWp/MWh in this example. Another reason for lower installed PV sizes in Australia is the higher PV performance. An average PV system produces 1.3-1.4 MWh per installed kWp in New South Wales, while a PV system only generates approx. 0.9 MWh/kWp in Kassel, Germany. As only a certain amount of PV coincides naturally with the load, even smaller sized systems run into an upper self-consumption limit of 50 to 70 % of the generated PV power without battery systems in Australia for the analyzed scenarios. Since PV systems are still sized according to the higher FIT and thus a higher grid feed-in in Germany, PV self-consumption in Germany only reaches 30 to 50 % depending on the household and on the battery size.

While the battery capacities are installed with 0.5 kWh per MWh of yearly load demand in Australia, the ratio is around 0.8 kWh/MWh for most households in Germany for the displayed example. Yet, the TOU tariff and the low FIT lead to battery installations even with higher battery investment cost in Australia. Furthermore, the difference in expected battery lifetime is noticeable in the sizing results. For the Australian case study the battery is replaced after 10 years which also implies an increase of overall cycles over the calculation time. In Germany, the battery is expected to last for 20 years and for less overall cycles as no replacement is assumed. Hence, batteries are installed with higher capacities compared to the Australian case study to allow for a similar energy throughput over their lifetime.

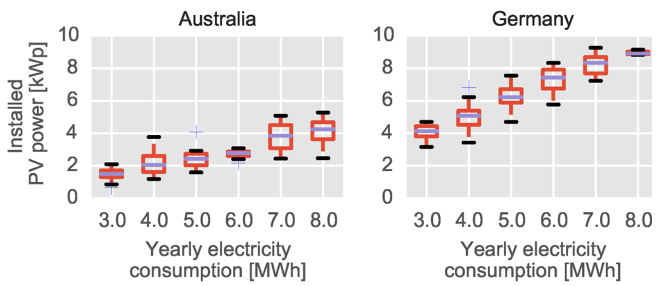

Fig. 1. Comparison of optimized PV sizes for Australia and Germany Assumptions: Bat. capacity: 800 AUD/kWh & 600 EUR/kWh, Bat. inverter: 600 AUD/kVA & 400 EUR/kVA, PV system: 1,600 AUD/kWp & 1,600 EUR/kWp, El. price dev.: 2.5 % (both), RRR: 4 % (AUS) & 2 % (GER), Battery lifetime: 10 y. (AUS) & 20 y. (GER), PP: 20 y. (both)

A sensitivity analysis for the different parameters in Australia points out the significant impact of payback periods and

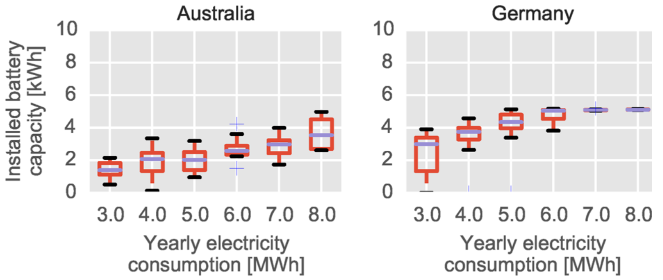

Fig. 2. Comparison of optimized storage sizes for Australia and Germany
Assumptions: Bat. capacity: 800 AUD/kWh & 600 EUR/kWh, Bat. inverter: 600 AUD/kVA & 400 EUR/kVA, PV system: 1,600 AUD/kWp & 1,600 EUR/kWp, El. price dev.: 2.5 % (both), RRR: 4 % (AUS) & 2 % (GER), Battery lifetime: 10 y. (AUS) & 20 y. (GER), PP: 20 y. (both); same assumptions as Figure 1

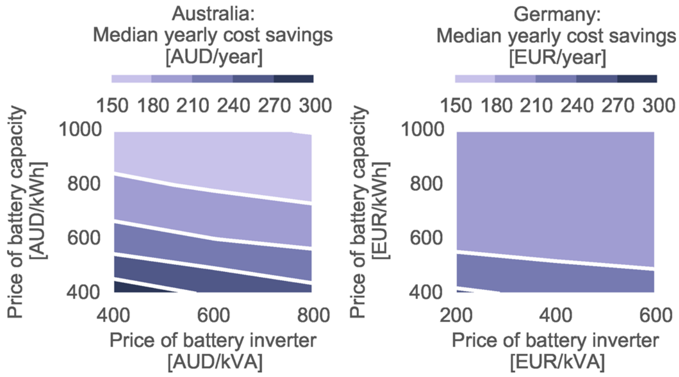

Fig. 3. Comparison of median yearly electricity cost savings through optimized PV or PV battery systems for Australia and Germany
Assumptions: PV system: 1,600 AUD/kWp & 1,600 EUR/kWp, El. price dev.: 2.5 % (both), RRR: 4 % (AUS) & 2 % (GER), Battery lifetime: 10 y. (AUS) & 20 y. (GER), PP: 20 y. (both); same assumptions as Figure 1

RRR on the decision to invest into a battery and its size. Reducing the payback time to 10 years, not only reduces the median installed PV power from 2.6 kWp to 1.5 kWp, but also leads to a median battery size of only 0.5 kWh. Additionally, increasing the RRR to 6 % results in stand-alone PV systems without batteries for capacity prices around and above 600 AUD/kWh. For an RRR 6 % and a payback period of 10 years only battery prices around 400 AUD/kWh would result in similar sizes as presented in Section 2. PV system sizes do not necessarily increase with dropping battery prices, yet higher battery capacities are installed. This is a result of increased direct battery charging from the grid. For low battery prices, 10 % of the load demand is served through battery charging from the grid. As this amount does not meaningfully change when varying payback period or RRR, it can be concluded that the TOU tariff incentivizes prices arbitrage to that amount of energy. Here, it is economically more efficient to operate the battery according to the TOU price differences rather than investing in a larger PV system to provide more energy locally.

In Germany, PV battery systems are only preferred over stand-alone PV systems for prices below 600 EUR/kWh, a payback higher than 10 years and a RRR of 2 %. Even for battery prices of 400 EUR/kWh, a stand-alone PV system reaches a higher NPV if the investor expects a RRR of 4 %. A higher increase in electricity prices offsets these trends, but also increases the uncertainty of the investment and therefore would require a higher RRR. Including the battery replacement option and willingly decreasing the battery lifetime to lower the needed battery capacities might also be an option for the German market.

Figure 3 shows the yearly median cost savings over all households depending on battery capacity prices and battery inverter prices for both countries. These cost savings are calculated by determining the investment's NPV and subtracting it from the household's original electricity costs without a PV or a PV battery system.

One can observe that the median yearly cost savings vary from 150 to 300 AUD depending on battery capacity and battery inverter prices in Australia. As pointed out above, stand-alone PV systems lead to higher savings than PV battery systems for battery prices above 600 EUR/kWh in Germany in this example. Thus, savings start to increase once battery prices fall below this threshold. The installation of a PV system leads to reduction of yearly electricity costs in both countries. A storage system can increase the yearly savings depending on system prices. As yearly savings highly depend on the household's yearly electricity consumption, individual savings might be lower or higher than the displayed median savings.

III. Grid Integration of PV Battery Systems

Despite the economics, PV battery systems are getting installed in Germany and influence the power flows over the household's point of common coupling (PCC) into the distribution grid. While the literature and grid operators have so far focused on addressing PV related grid integration challenges through different active and reactive power control strategies using the PV inverter's control capabilities [7], [30], [31], battery systems might offer an alternative to PV curtailment [10]. Yet, TOU tariffs and regulatory requirements impact battery operation which distribution grid operators need to incorporate in their grid planning and grid operation practices. The impact of a PV or a PV battery system on grid planning issues is mainly determined by its control strategy, its max. grid feed-in and its contribution to the demand peak [32], [33]. Thus, this section aims at analyzing the grid planning indicators for optimized PV battery sizes.

A. Peak analysis and standard load profiles

Several papers have pointed out the potential which storage systems provide for PV grid integration [8], [9], [10], [34], [35], [36]. Yet, PV battery systems which are solely operated with a rule-based control approach for increasing PV self-consumption tend to be fully charged before PV generation reaches its peak [10]. To investigate the influence on the load peak and the feed-in peak, the following approach is used.

The residual power flow E_{RES} is calculated by summing all power flows over each household (HH)'s PCC:

$$\sum_{\forall HH} (E_{PV2Grid,HH}(t) - E_{Grid2Load,HH}(t) - E_{Grid2Bat,HH}(t)) = E_{RES} \quad \forall\, t \in Time \quad (6)$$

From this the minimum, the peak load, and the maximum, the peak feed-in, are determined. These new peak values are compared to the load only scenario and scenario with PV systems without batteries. This allows quantifying potential reductions of peak load and peak feed-in as a result of battery operation.

To analyze battery operation over time, new standard load profiles (SLP) are derived for the simulated systems. Therefore, the residual household profiles are categorized into three different day types: weekday, Saturday and Sunday. The average over all residual household profiles is calculated for these three day types for each month of the year. The new SLPs display for example how ramps in the system are changing and how typical charging and discharging for batteries are influenced by TOU tariffs.

Both indicators are calculated using the sizing and operation results from Section II.

B. Case study Australia

Based on the assumptions used in Figure 1 and Figure 2, the results of the peak analysis for the Australian case study are presented in Figure 4. The peak load is reduced by 16 % compared to the peak of the load only scenario. The peak feed-in reduced by only 1.5 % compared to the peak of PV systems without batteries. Hence, investment and operation of PV battery systems have a positive impact on the grid in this example. Additionally, it becomes visible that the peak load is still the relevant grid planning factor as the PV feed-in peak remains 8 %-points below the load peak in the PV battery scenario.

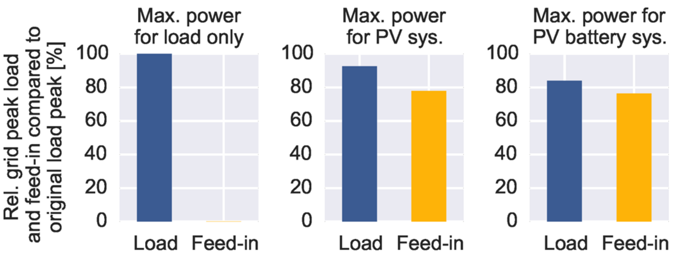

Fig. 4. Max. demand and feed-in depending on system configuration for the Australian case study
Assumptions: Bat. capacity: 800 AUD/kWh, Bat. inverter: 600 AUD/kVA, PV system: 1,600 AUD/kWp, El. price dev.: 2.5 %, RRR: 4 %, Battery lifetime: 10 y., PP: 20 y.; same assumptions as Figure 1

To provide grid operators with indicators which describe the grid impact of battery systems under different economic assumptions, Figure 5 displays the average change in peak load and peak feed-in per PV battery system for different battery capacity and inverter prices. The indicators aim at allowing for an easy integration of PV battery systems into existing grid planning processes. Furthermore, the average battery capacity and PV system are displayed to indicate which type of system configuration leads to the resulting peak load and peak feed-in changes.

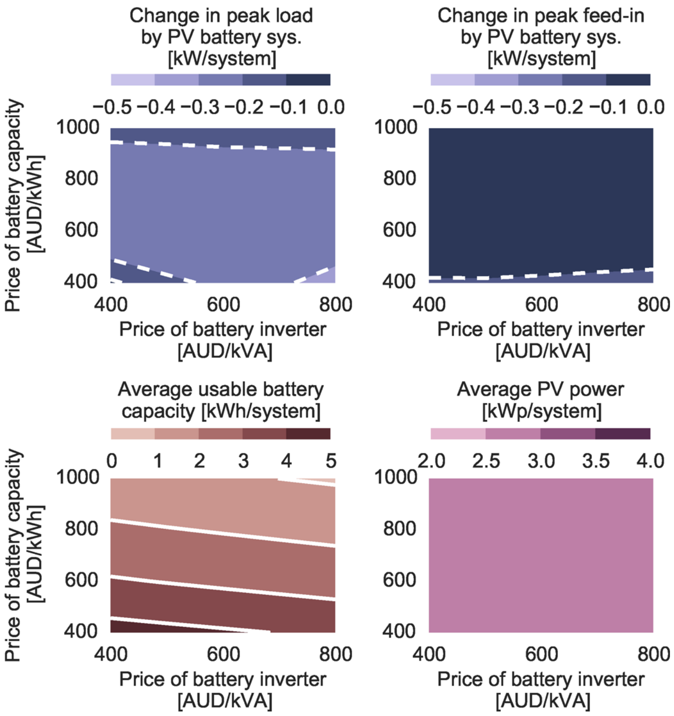

Fig. 5. Peak impact analysis for the Australian case study (compared to load only scenario)
Assumptions: PV system: 1,600 AUD/kWp, El. price dev.: 2.5 %, RRR: 4 %, Battery lifetime: 10 y., PP: 20 y.; same assumptions as Figure 1

The results show that a peak load reduction of 0.3 kW per installed system is achievable even for higher battery prices and smaller installed capacities. It becomes visible that low capacity and low inverter prices result in a smaller peak reduction potential. This is a result of the TOU tariff which increases the load simultaneity as all installed battery system act according to the same price signal and charge simultaneously from the grid. This underlines the hypothesis that a PV battery system does not necessarily have to act in a grid supporting manner. To prevent that batteries actually increase the peak load, different TOU structures or charging limits for battery systems are suitable solutions. The PV induced peak does not change for most price combinations; only capacity prices below 400 AUD/kWh introduce sufficiently sized systems to achieve a peak reduction. Overall, both peak reductions are fairly small, but indicate the peak reduction potential that batteries could provide if operated according to a TOU tariff. Yet, this potential highly depends on the design of such TOU tariffs.

Figure 6 compares the load only SLP with the new average SLP for one household with a PV and with a PV battery system.

When comparing the SLPs of PV only and of PV battery systems, a peak shaving effect for load and PV becomes

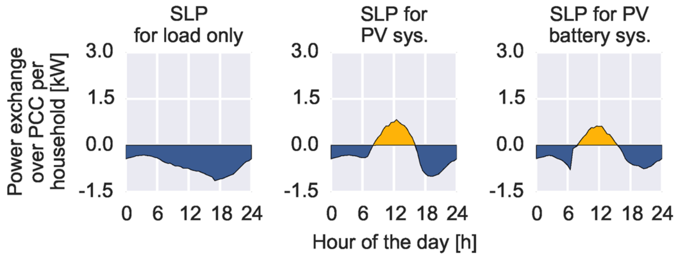

Fig. 6. Standard load profiles depending on system configuration for a weekday for a summer month for the Australian case study
Assumptions: Bat. capacity: 800 AUD/kWh, Bat. inverter: 600 AUD/kVA, PV system: 1,600 AUD/kWp, El. price dev.: 2.5 % , RRR: 4 %, Battery lifetime: 10 y., PP: 20 y.; same assumptions as Figure 1

visible. Additionally, the effect of simultaneous charging according to the TOU is noticeable close to 7 am. As a price jump happens at 7 am and not enough PV is available for the following hours, battery charging from the grid causes quite a steep power ramp. Such steep ramps might complicate grid operation.

C. Case study Germany

Figure 7 presents the relative change in peak load and peak feed-in for the German case study. In contrast to the Australian case study, the PV related feed-in peak exceeds the load peak in this case study for both PV cases (PV only and PV battery systems). Even though the battery systems are able to reduce the PV induced peak significantly, they are not able to totally offset it. Thus, PV related grid reinforcement would be deferred but not avoided in this example.

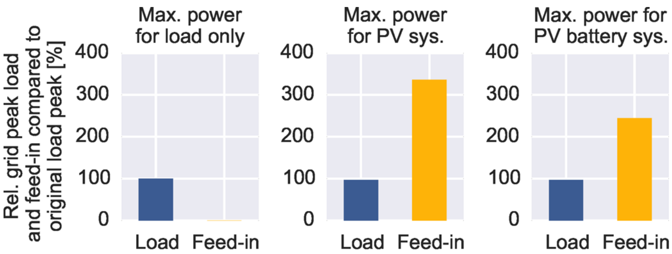

Fig. 7. Max. demand and feed-in depending on system configuration for the German case study
Assumptions: Bat. capacity: 600 EUR/kWh, Bat. inverter: 400 EUR/kVA, PV system: 1,600 EUR/kWp, El. price dev.: 2.5 %, RRR: 2 %, Battery lifetime: 20 y. , PP: 20 y.; same assumptions as Figure 1

Figure 7 and Figure 8 show that battery systems have no impact on the peak load. The peak load typically occurs in the early evening on a winter weekday in Germany. As PV generation is also not high during such days and there is no economic incentive to charge the battery from the grid, the battery is typically at its lower bound of the state of charge when the peak load occurs. Hence, it is not able to provide energy to reduce the demand.

For the change in PV peak feed-in, the absolute peak reduction per installed system increases with an increasing PV size. This is a result of the active power limit which is higher for PV battery systems than for PV only systems. By investing

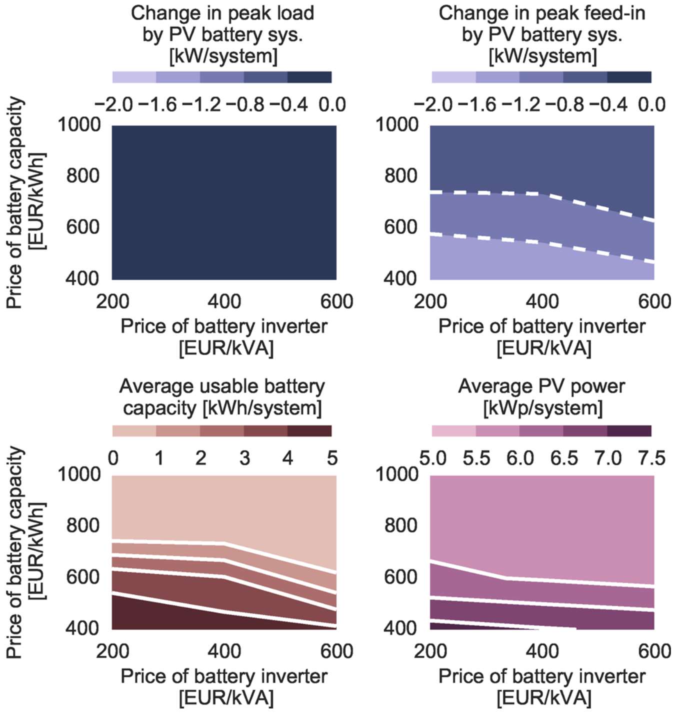

Fig. 8. Peak impact analysis for the German case study (compared to load only scenario)
Assumptions: PV system: 1,600 EUR/kWp, El. price dev.: 2.5 %, RRR: 2 %, Battery lifetime: 20 y. , PP: 20 y.; same assumptions as Figure 1

in a battery system and receiving an investment bonus from the German government, PV battery owners agree to lower their max. PV grid feed-in to 60 % of the installed PV capacity. Thus, higher absolute peak reductions per system are achieved. This incentive to operate the battery in a peak shaving manner becomes visible in Figure 9 as the peak feed-in is slightly reduced. Again, the positive grid impact of the battery highly depends on the operational incentives for the control strategy.

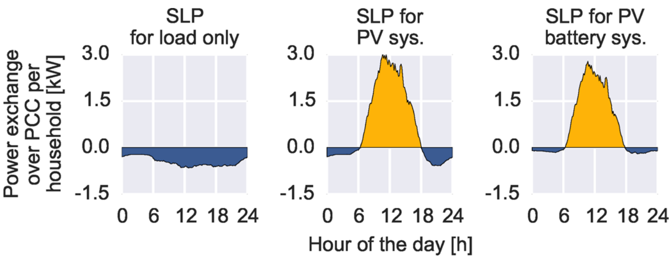

Fig. 9. Standard load profiles depending on system configuration for a weekday for a summer month for the German case study
Assumptions: Bat. capacity: 600 EUR/kWh, Bat. inverter: 400 EUR/kVA, PV system: 1,600 EUR/kWp, El. price dev.: 2.5 %, RRR: 2 % , Battery lifetime: 20 y., PP: 20 y.; same assumptions as Figure 1

IV. Conclusions

As system prices for PV and battery systems drop, electricity prices rise and FIT decrease in Australia and Germany, a business opportunity for battery systems emerges as they allow increasing consumption of locally produced PV energy without changing the load behavior. Furthermore, TOU pricing and tightened interconnection requirements for PV systems incentivize the usage of storage systems.

This paper presents a grid impact analysis to assess the consequences of changing market conditions on optimally sized and operated PV battery systems, and their influence on the distribution grid. The sizing and operation is solved using a mixed integer linear problem formulation. The grid impact is then evaluated by performing a peak power analysis and by quantifying the absolute change in peak power depending on a range of system configurations. Characteristic battery charging and discharging schedules are derived from the standard load profiles produced by the optimized systems.

The results show that small scale PV battery systems will be an economically viable option in the near future and can lead to yearly electricity cost savings in Australia, especially since current TOU tariffs provide an additional revenue stream which helps refinancing the systems. Furthermore, a small reduction in peak load is achievable in the presented Australian case study. In contrast, in Germany stand-alone PV systems will provide the economically most attractive option, given the current battery prices. Nevertheless, the market for PV battery systems may continue to grow, as not only economics influence the investment decision.

The two case studies show that the positive grid impact of such battery systems highly depends on the underlying economic and regulatory frameworks. It is observed that TOU tariffs in Australia might also lead to an increase in peak load resulting from simultaneous battery charging from the grid during low price electricity periods. In Germany, the introduced active power limit for PV feed-in seems to provide a strong incentive to operate batteries in a PV peak-oriented manner. Mitigating such load and PV peaks using battery systems helps to reduce grid reinforcement costs for the grid operator and increases the local PV hosting capacity. Yet, the grid operator does not necessarily benefit from such PV battery systems, especially if they are just operated to minimize the household's electricity cost.

Hence, future research should integrate both stakeholders - households with PV battery systems and the grid operator - in one multi-objective optimization approach which ensures benefits for all stakeholders. Moreover, the option to increase the PV hosting capacity by exploiting the additional reactive power capability of the battery inverter instead of managing active power flows should be investigated.

Acknowledgment

The research leading to these results has received funding from the European Union Seventh Framework Programme (FP7/2007-2013) under grant agreement n°609687, as part of the ELECTRA REX researcher exchange programme. The work has also been supported by the German for Economic Affairs and Energy through the projects "INE-VES" and "HiPePV2" (FKZ: 0325561A, 0325785) and by ARENA, the Australian Renewable Energy Agency, through the VPS2 Project. Any opinions, findings and conclusions or recommendations expressed in this material are those of the authors and do not necessarily reflect those of the funding parties.

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