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Leaving the grid: An ambition or a real choice?

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HIGHLIGHTS

- There is an increasing public and academic interest in "leaving the grid" or "living off-grid".
- Grid defection is argued as a "death spiral" for transmission and distribution industries.
- An optimization methodology is developed for assessing the feasibility of leaving the grid.
- Leaving the grid with PV–battery is found to be infeasible due to large system requirements.
- The best is to preserve connection with the grid, but minimize the electricity purchase.

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ABSTRACT

The recent rapid decline in PV prices has brought grid parity, or near grid parity for PV in many countries. This, together with an expectation of a similar reduction for battery prices has prompted a new wave of social and academic discussions about the possibility of installing PV–battery systems and "leaving the grid" or "living off-grid". This, if uncontrolled, has been termed the "death spiral" for utility companies.

We have developed a decision support tool for rigorous assessment of the feasibility of leaving the grid. Numerous sensitivity analyses are carried out over critical parameters such as technology costs, system size, consumer load, and feed-in-tariff. The results show that, in most cases, leaving-the-grid is not the best economic option and it might be more beneficial to keep the connection with the grid, but minimize the electricity purchased by installation of an optimized size of PV-battery systems.

The policy implication of this study is that, from an economic perspective, widespread disconnection might not be a realistic projection of the future. Rather, a notable reduction of energy demand per connection point is a more realistic option as PV–battery system prices decline further. Therefore, policies could be devised to help electricity network operators develop other sources of revenue rather than increasing energy prices, which have been assumed to be the key driver of the death spiral.

1. Introduction

1.1. Energy security and consumer independence

The substantial drop in cost for photovoltaic (PV) systems in recent years has triggered very strong uptake in many countries. While the global cumulative installed capacity of PV was 1.4 GW in year 2000, it exceeded 100 GW (102.16 GW) at the end of 2012 (EPIA, 2013) and 138.9 GW by the end of 2013 (Masson et al., 2014). This has increased its social acceptance and with the commoditization of panels, inverters and associated components has made its installation at the demand side very convenient. The possibility of generating power at the demand side and converting the "consumers" to "prosumers" (producers and consumers), has numerous advantages in terms of energy efficiency as, it can reduce some power losses due to network transmission and distribution, the network footprint, reserve generation capacity, etc. Of course, the extent of these benefits depends on system configuration and penetration levels (Cossent et al., 2010; Quezada et al., 2006). Along with other forms of distributed generation and battery energy storage for end-users, the topology and operation of future electricity networks may become very different to the legacy system.

Fig. 1 illustrates the historical and potential future trends of dominant distributed generation systems at small-scale sites both on- and off-grid. Renewable energy sources generally suffer from two key limitations i.e. variability and low availability. These constraints firstly result in a low or modest capacity utilization

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Nomenclature

A_i	area of PV system i
A^m	maximum acceptable area of all selected PV systems
B_{jp}	input–output balance of battery system j at period p
CR_j	maximum possible charge rate of battery system j
DR_j	maximum possible discharge rate of battery system j
CX_j^B	capex of battery system i
CX_i^{PV}	capex of PV system i
FiT_p	FiT during period p
FP_p	failure penalty during period p
EP_p	electricity price during period p
FOM_{jp}^B	fixed operation and maintenance costs for battery system j during period p
FOM_{ip}^{PV}	fixed operation and maintenance costs for PV system i during period p
GHI_p	GHI during period p
H	segments of planning horizon
I	number of candidate PV systems
InD	grid independence level
J	number of candidate battery systems
L_p	electricity demand during period p
LLP	loss of load probability
N^{PV}	maximum number of selected PV systems
N^B	maximum number of selected battery systems
NPV	net present value
P'	number of periods per h
R	reliability
r	discount rate
S	saving over the planning horizon
S_j^B	size of battery system i
S_i^{PV}	size of PV system i
SOC_{jp}	SOC for battery system j during period p
SOC_j^L	lower bound of SOC for battery system j
SOC_j^U	upper bound of SOC for battery system j
T_p	weather temperature during period p
USE_p	unserved energy during period p
W_p	wind speed during period p
X_{jp}^{BL}	AC power sent from battery system j to load during period p
X_{ijp}^{PB}	DC power sent from PV system i to battery system j during period p
X_{ip}^{PL}	DC power sent from PV system i to load during period
y_i	binary variable to indicate if PV system i is selected
y'_j	binary variable to indicate if battery system j is selected
β_{jp}	self-discharges of battery system i during period p
η_j^C	nominal charge efficiency of battery system i
η_j^D	nominal discharge efficiency of battery system i
η_{jp}^C	battery charge efficiency of system i during period p
η_{jp}^D	nominal discharge efficiency of battery system i during period p
η_i^{PV}	nominal (standard) design efficiency of PV system i
η_{ip}^{PV}	efficiency of PV system i during period p
η_j^{CC}	efficiency of charge controller for battery system j
η_i^{PVin}	inverter nominal efficiency for PV system i
η_j^{Bin}	inverter nominal efficiency for battery system j

Subscripts

h	indicator of time segment
p	indicator of period
i	indicator of PV system
j	indicator of battery system

Abbreviations

CC	charge controller
DoD	depth of discharge
FOM	fixed operation and maintenance
LLP	loss of load probability
PR	performance ratio
SOC	state of charge
ToU	time-of-use
USE	unserved energy
UUE	unused energy

factor and thus high upfront investment costs (though low operational costs). Secondly, the natural unavailability of the energy source (solar radiation, wind, biomass, etc.) for some time periods (hour, day, week, season, etc.) requires either an auxiliary power source (i.e. other types of generation or connection to the grid) or energy storage. As such, till the late 2000s the costs of renewable-based DG technologies (such as PV) were high and the technologies were well above parity with grid supplied electricity without subsidy. Therefore, when the grid was available, it was the cheapest source of electricity generation (Fig. 1a). Otherwise, fossil fuel generators were the most feasible option (Fig. 1b). However, the recent fast decline in PV prices has brought grid price parity for PV in many regions of some countries, especially where solar insolation is high. This has resulted in the emergence of new supply configurations (Fig. 1c–e). For instance, in many locations it is feasible to install PV systems at the household level even if grid supply is available. For example, when sufficient insolation is available PV can supply the demand, and if there is a shortfall it can made up from the grid (Fig. 1c). When the grid is unavailable, depending on prices of technology and fossil fuels, an optimal combination of PV, battery, and on-site generation using fuel could meet the demand (Fig. 1d and e). In off-grid applications, electricity storage is an inseparable part of PV generation if close to 100% reliability is sought. According to the IEA, “as PV matures into mainstream technology, grid integration and management and energy storage become key issues” (IEA, 2010). However, the high cost of batteries has traditionally prevented its use when grid power is available. In recent years however, the price of suitable batteries has also started to decline and it is anticipated that battery technology may follow the rapid downward price trajectory of PV (Szatow et al., 2014) as manufacturing scale increases. For example, the Information Handling Services (IHS) predicts a 35% reduction in residential battery storage systems by 2017 (Wilkinson and Ward, 2013). Therefore, the widespread implementation of PV technology along with the declining trend in battery prices has led to the introduction of a third configuration, i.e. the grid-connected PV–battery system (Fig. 1f).

The technology transformation underway at the demand-side has not stopped. The projection for continuous reduction in PV prices and a similar trend for battery storage has generated considerable public interest and excitement for “leaving the grid” or “living off-grid” as illustrated in Fig. 1g. Psychologically, this interest might refer to the same evolutionary desires of “security” or “independence” in its very individualistic level, micro-independence. The benefits or disadvantages of this for the consumers is not the topic of this study as it requires socio-behavioral

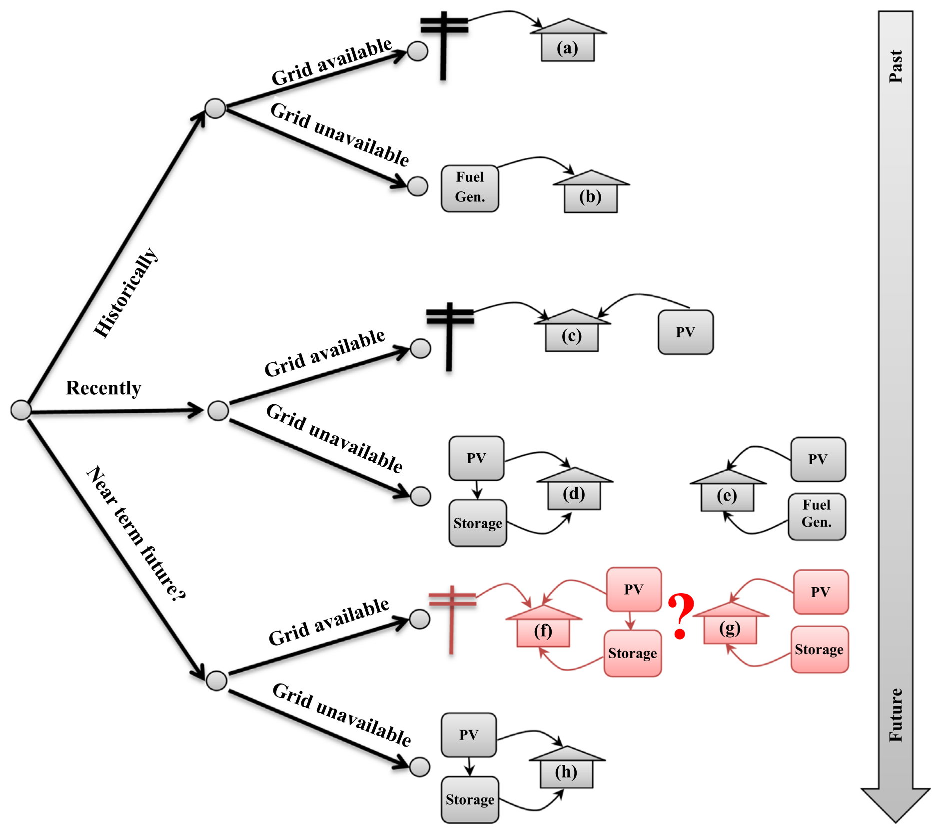

Fig. 1. Historical and future trend of dominant demand side distributed generation systems.

studies. Here, our goal is to investigate the economic feasibility of leaving the grid from the end user point of view.

1.2. *Leaving the grid and the "death spiral"*

A key societal concern of leaving-the-grid is the consequent escalation of retail electricity prices for those remaining connected. The residential electricity bill consists mostly of three key elements i.e. a component due to the wholesale electricity price, network costs and the retailer margin and administration costs. The network cost is the levelized cost of grid transmission and distribution infrastructure, which for instance accounts for around 45% of Australian retail electricity costs (Simshauser and Nelson, 2012). Given this, when some of the customer base are transformed to prosumers and leave the grid, the network cost will be distributed over fewer customers and thus the network charge will increase. The consequent rise of electricity prices will further improve the economic attractiveness of leaving the grid for any remaining customers and will expedite grid defection (Simshauser and Nelson, 2012). This is referred to as the death spiral for utility companies (Severance, 2011).

The Edison Electric Institute in a report titled "Disruptive Challenges" argues the accuracy of the perception that intermittency of renewable DER will keep the customers connected to the grid until non-intermittent DER is fully feasible. The report highlights the possibility of battery storage technology or micro turbines to allow customers to get disconnected from the grid (Kind, 2013). Recently, Bronski et al. (2014) undertook an extensive model-based economic analysis (using the Homer software package) of grid disconnection through finding grid-parity for PV–battery systems in each region. The analysis was focused on five representative US regions (New York, Kentucky, Texas, California, and Hawaii) with the objective of understanding how soon this grid defection could happen.

The concern over grid defection has also been considered in some planning studies. For example, the national level Future Grid Forum (FGF) project led by CSIRO, Australia, studied four different scenarios for the future grid (by 2050) of the Australian national electricity market (NEM) with the main focus on consumer uptake of distributed energy systems (Future-Grid-Forum-participants, 2013). The study allocated one of the four scenarios (Leaving the Grid Scenario) to the case that the continued reduction of battery prices will motivate many customers to totally disconnect from the grid by managing their own generation together with battery storage rather than receiving the service from utilities. The study, though conservative, projected that by 2050, around one-third (32%) of the customers may leave the grid.

In contrast, the study by the Electric Power Research Institute (EPRI) (EPRI, 2014) states that the full value utilization of distributed renewable resources requires connection to the grid – i.e. "DER and the grid are not competitors but complements". According to EPRI's study (published February 2014), leaving the grid with residential PV could cost 4–8 times more than connection to the grid in the US (EPRI, 2014).

In this study we will focus on PV as it is currently the most inexpensive and reliable source of residential scale power generation for many regions especially in Australia, parts of the USA, South Africa, parts of Southern Europe and South America. We will look at the potential use of PV and battery storage as an integrated system to supply a prosumer's demand. More specifically, we will investigate a few scenarios for prosumers and analyze under what conditions it becomes economically feasible for the prosumer to leave the grid. Each case study will be accompanied by a comprehensive comparative assessment of various parameters and their impact on the feasibility of grid defection.

1.3. Literature on the modeling of PV–battery systems

It is over a century since the first industrial application of (lead acid) batteries (Vassallo, 2015) and over half a century since the first application of PV technology. As such the sizing of PV–battery systems has a history of five decades. Initial attempts in the sizing of integrated PV–battery systems were mainly focused on off-grid and rural areas using approximate methods, which resulted in over- or under-sized systems (Gordon, 1987). Later, iso-reliability curves were introduced by Egido and Lorenzo (1992) which is based on developing numerous graphs of PV-storage sizes, each at a certain reliability value. As computers emerged, PV–battery sizing models also improved in rigorousness. For instance, instead of daily average solar irradiation or load data, real historical time series were used (Fragaki and Markvart, 2008; Lorenzo and Narvarte, 2000), or characteristic equations were used instead of simple efficiency values for PV panel, battery, inverters (Peippo and Lund, 1994), etc. Some studies have also used artificial intelligence techniques for sizing PV–battery systems (Mellit et al., 2009).

With the global attention to the PV transformation within the last decade, there has been increasing interest in developing optimal operation schedules for PV and/or battery systems. Lu and Shahidehpour (2005) developed a short-term scheduling model for battery use in a grid-connected PV–battery system using a Lagrangian relaxation-based optimization algorithm to determine the hourly charge/discharge commitment of a battery in a utility grid. Riffonneau et al. (2011) presented a dynamic programming methodology for “day-ahead” predictive management of grid connected photovoltaic (PV) systems with storage. The program, which also considered battery aging, could successfully achieve its peak-shaving goal at minimum costs. Yu et al. (2013) studied the problem of determining the size of battery storage for grid-connected PV systems. They identified a unique critical value for the battery size, below which the total electricity cost was large while above that limit, an increase in battery size did not impact on costs. Ratnam et al. (2013) developed a framework based on quadratic programming which enables the customer to justify expenditure on battery storage through either a least cost option of capital investment or choose to utilize existing electric vehicle (EV) battery storage, if available.

Pedram et al. (2010) have argued that the current homogenous energy storage systems (EES) have limitations in simultaneously achieving desirable performance features such as high charge/discharge efficiency, high energy density, low cost per unit capacity, and long cycle life. As such they have proposed the application of hybrid EES (HEES) systems with each EES element having strength in a certain performance feature. Stadler et al. (2014) developed a Distributed Energy Resources Customer Adoption Model (DER-CAM) which is based on a mixed integer optimization program. The model is capable of using various distributed generation and storage types. Wang et al. (2013) developed a dynamic programming model for the integration of a residential-level HEES systems for smart grid users equipped with PV power generation. The program objective was to reduce the total electricity cost over a billing period and perform peak power shaving under an arbitrary energy price and considering characteristics of different types of EES elements, conversion efficiency variations of power converters, as well as the time-of-use (ToU) dependent energy price function. Khalilpour and Vassallo (2014, 2015) developed a multi-period mixed-integer decision support program with the objective to maximize saving by minimizing the consumer's electricity bill. The model is capable of identifying the feasibility of an investment in PV and/or battery systems, and the specifications of the optimal system. This decision support program enables the consumer (spanning from a small house to large-scale industrial plants) to implement the most efficient electricity management strategy while achieving the goal of minimizing the electricity bill. Bronski et al. (2014) using the Homer software package performed an extensive economic study of grid defection through finding the grid-parity of PV–battery systems. The analysis was focused on five representative US geographies (New York, Kentucky, Texas, California, and Hawaii) with the objective of understanding how soon this “grid defection” could happen. The model showed that grid parity is already there for a minority of electricity customers with high electricity prices, e.g. Honolulu in Hawaii with the 2012 retail electricity price of 0.34–0.41 $/kWh. Grid parity will be there for Westchester in New York (∼0.15–0.20$(2012)/kWh) before 2030, and at early 2030s for Los Angeles (~0.09–0.17 $(2012)/kWh). The states of Texas and Kentucky will have grid parity in the late 2040s due to their very low retail electricity prices (~0.05–0.09 $(2012)/kWh).

The goal of the research reported here is to use the model of Khalilpour and Vassallo (2014, 2015) to assess, with a rigorous approach, the feasibility of leaving the grid using PV and battery storage. We describe a few case studies and through the optimal solutions investigate the best decision action for customers. The result is the optimal selection, sizing and operation scheduling of grid-connected/off-grid PV–battery system with respect to dynamics of historical/projected periodical weather data, electricity price, PV/battery system cost, PV/battery aging, and other critical design and operation parameters.

2. Methods

2.1. Problem: feasibility of leaving the grid with an optimal PV–battery system

Consider an end-user electricity consumer who is analyzing their electricity usage for a planning horizon of H segments (weeks, months, years) with P' multiple periods with a given fixed length (minute, hour, etc.). As such, the planning horizon consists of $P=H\times P'$ total periods (p: 1, 2,…, P). The current optimization study is occurring in the base period ($p=0$). The consumer is expecting their electricity demand to be L_p kWh during period p.

The consumer is interested to investigate the feasibility of solar PV systems with battery storage systems to supply its electricity demand at a given reliability, R, during the planning horizon and enables it to cease its contract and leave the grid. Fig. 2 shows the schematic of the decision problem. The PV system can generate electricity to use directly or stored in the battery to be used later.

There are numerous PV and battery suppliers in the market, with a wide range of costs, sizes, efficiencies and operational performances. The consumer is considering I (i: 1, 2, …, I) number of PV systems each with capital cost of CX_i^{PV} to ultimately select the best one(s). Each PV has design specification of S_i^{PV} kW and surface area of A_i with nominal (standard) design efficiency of η_i^{PV}. The real PV efficiency at any period p is taken as η_{ip}^{PV} which is a function of many parameters such as aging, wind speed (W_p), ambient temperature (T_p), dust, irradiation (GHI_p) etc., (Lasnier, 1990). Sometimes, the term performance ratio (PR) is used to address the real efficiency (Dierauf et al., 2013). PR is obtained by dividing the real PV efficiency over the nominal efficiency of one. It is noteworthy that the consumer might have a space limitation which does not allow installation of a PV system with area greater than A^m.

Likewise, the consumer also considers J (j: 1, 2, …, J) number of battery systems with capital cost of CX_i^B to select the best one(s). Each battery has a nominal size of S_j^B kWh, with nominal charge and discharge efficiency of η_j^C and η_j^D, respectively. The real

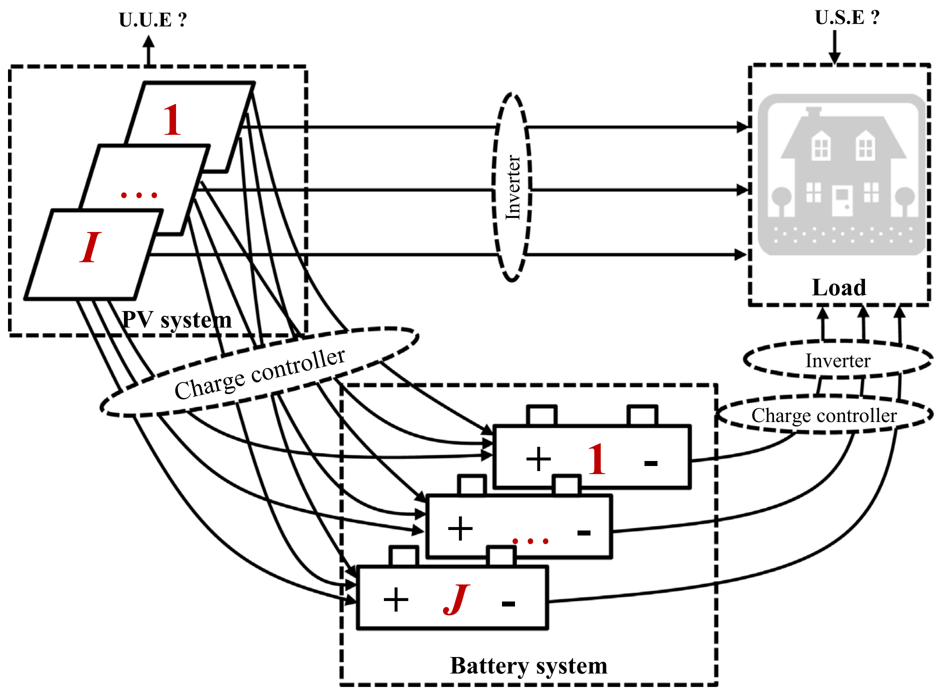

Fig. 2. Schematic of a grid-disconnected electricity system of an end user customer with PV system and battery storage (UUE: unused energy; USE: unserved energy).

battery charge/discharge efficiency is a function of numerous parameters, the most important of which is temperature. The real charge and discharge efficiency at each period p is taken as η_{jp}^{C} and η_{jp}^{D}, respectively. The battery also self-discharges with a rate of β_{jp} at any period p. Each battery has a lower bound and upper bound on its state of charge (SOC), SOC_j^L and SOC_j^U, to prevent sharp detoriation of its life specifically due to high depth of discharge (DoD) (Chaurey and Deambi, 1992). As such, the battery needs a charge controller (CC) with efficiency of η_j^{CC} for regulation of the input/output power. Batteries also have limitations on the rate of charge/discharge, usually expressed as the C-rate. We take CR_j and DR_j as the maximum possible charge and discharge rates of the battery, respectively, per period. The inverter nominal efficiency is taken as η_i^{PVin} and η_j^{Bin} for PV and battery, respectively. If the inverters' efficiency is taken as a nonlinear (quadratic) function of input power (Velasco et al., 2010), it can be taken as a variable (a function of input power flow) at each period p, for PV and battery system, η_{ip}^{PVin} and η_{jp}^{Bin}, respectively. However, this will convert the linear program (LP) formulation into a nonlinear program. The formulation, in this study, accommodates both options (inverter efficiency as a parameter or a variable) so that the users can choose based on their preferences.

Given the current retail electricity price and all other possible parameters, the consumer anticipates that the electricity price will be EP_p at period p (p: 1, 2,..., P). The feed-in-tariff (FiT) for selling electricity to the grid is highly policy-related and the consumer projects the value of FiT_p during period p over the planning horizon. There is a connection fee or supply charge of CF_p over period p.

Having the capex of PV system with CX_i^{PV} \$/kW and capex of battery with CX_j^{B} \$/kWh, this problem can now be stated. Given the above data, identify the best investment plan in solar PV and battery to minimize the electricity cost over the planning horizon. Also determine the followings:

(1) whether to install PV and/or battery systems.
(2) The size of PV and/or battery systems if they are feasible to install.
(3) The periodical operation schedule of the PV system (if selected).
(4) The periodical operation schedule of the battery system (if selected).

2.2. Problem formulation

Accordingly, this is a planning problem that involves some decisions at different periods over the planning horizon. We define the following binary variable for each candidate PV system i:

$$y_i = \begin{cases} 1, & \text{if PV system } i \text{ is selected} \\ 0, & \text{otherwise} \end{cases} \qquad 1 \le i \le I$$

To limit the number of selected PV systems, N^{PV}, we use

$$\sum_{i=1}^{I} y_i \le N^{PV} \tag{1}$$

Similarly, we define the binary variable y_j' for candidate battery systems given by

$$y_j' = \begin{cases} 1, & \text{if battery system } j \text{ is selected} \\ 0, & \text{otherwise} \end{cases} \qquad 1 \le j \le J$$

$$\sum_{i=1}^{I} y_i' \le N^{B} \tag{2}$$

where N^B denotes the maximum number of battery selections. The installation area, (A^m) limitation is given by

$$\sum_{i=1}^{I} y_i A_i \le A^m \tag{3}$$

If PV system i is installed, its generated DC electricity at any period p, will have three possible destinations, i.e. meeting the local load, charging the battery or exporting to the grid. This is expressed as

$$y_i.\, A_i.\, GHI_p.\, \eta_{ip}^{PV} \le X_{ip}^{PL} + \sum_{j=1}^{J} X_{ijp}^{PB} \quad 1 \le i \le I,\ 1 \le p \le P \tag{4}$$

where X_{ip}^{PL} refers to the DC power sent from the PV system i to the load during period p. X_{ijp}^{PB} denotes the DC power sent from the PV system i to battery j (j: 1, 2, …, J) during period p.

The difference between the total PV output and the amount sent for load $\left(X_{ip}^{PL}\right)$ and batteries $\left(X_{ijp}^{PB}\right)$ is the unused energy (UUE) which is curtailed. This happens when there is redundant generation during period p at which the load demand is met and all J batteries are full. The curtailed UUE is given by

$$X_p^{UUE} = \sum_{i=1}^{I} \left(y_i.\, A_i.\, GHI_p.\, \eta_{ip}^{PV} - X_{ip}^{PL} - \sum_{j=1}^{J} X_{ijp}^{PB} \right) \quad 1 \le p \le P \tag{5}$$

The local load at any period p could be supplied from two sources, i.e. PV or battery. Also, the amount of demand that the electricity generation system (here PV–battery) fails to supply at any period p is addressed with unserved energy (USE). This is given by

$$USE_p = L_p - \sum_{i=1}^{I} \eta_{ip}^{PVin} X_{ip}^{PL} + \sum_{j=1}^{J} X_{jp}^{BL} \ge 0 \quad 1 \le p \le \mathrm{P} \tag{6}$$

where X_{ip}^{BL} is the AC energy received by the consumer appliances at period p. Also a constant value of loss of load probability (LLP) is used to refer to the overall fraction of the unserved energy over the planning horizon $\left(LLP = \sum_{p=1}^{P} USE_p/L_p\right)$. We define the level of “grid independence”, InD, as a complement of LLP i.e. $InD=1-LLP$. As such, the grid independence (or simply “independence”) level is given by

$$InD = \sum_{p=1}^{P} \left(\sum_{i=1}^{I} \left(\eta_{ip}^{PVin} X_{ip}^{PL} \right) + \sum_{j=1}^{J} \left(X_{jp}^{BL} \right) \right) / L_p \tag{7}$$

where $0 \le InD \le 1$. It is evident that leaving the grid option is possible when the 100% grid independence condition (i.e. $InD=1$) is met. The user has two options for dealing with the level of independence; one approach is to set a constraint of $InD=1$ to assure that 100% independence is met. In this scenario the model will identify a PV–battery configuration which satisfies this requirement. Alternatively, it can be left free so that the model identifies the optimal InD value (through Eq. (7)). As this value might be less than 1, we consider a failure penalty of FP_p for any unit of unserved electricity, during period p. The unserved energy can be supplied by any other source of power generation (e.g. diesel) or otherwise will result in power outage. Therefore, the value of FP_p is user-specific and could be also taken the same as retailer electricity tariffs or any desired values.

The battery j, if selected, can receive DC power from the PV (after passing through charge controller, CC), or the grid (after passing through inverter and charge controller). When needed, the stored DC electricity can be sent to the customer appliances or to grid also through the inverter. The battery input–output balance at period p is given by

$$B_{jp} = \left(1 - \beta_{jp}\right)\left(\eta_j^{CC} \eta_{jp}^{C} X_{ijp}^{PB} - X_{jp}^{BL} / \left(\eta_{jp}^{Bin} \eta_j^{CC} \eta_{jp}^{D}\right)\right) \quad 1 \le j \le J, \quad 1 \le p \le P \tag{8}$$

It is obvious that the battery balance, B_{jp}, takes a positive value when it is being charged and negative during discharging. With this, the battery state of charge for the scenario with PV system i and battery system j is given by

$$SOC_{Jp} = \sum_{p'=1}^{p} B_{jp'} \quad 1 \le j \le J, \quad 1 \le p \le P \tag{9}$$

As discussed, the SOC should always be controlled, during the operation, within a certain upper (SOC^U) and lower (SOC^L) bound. This is given by

$$y_j' SOC_j^L \le SOC_{jp} \le y_j' SOC_j^U \; 1 \le j \le J, \quad 1 \le p \le P \tag{10, 11}$$

Battery j cannot be charged/discharged above a certain rate (CR_j, DR_j) during any period p. This is given by

$$B_{jp} \le y_{jp}^B CR_j \quad 1 \le j \le J, \quad 1 \le p \le P \tag{12}$$

$$B_{jp} \ge -1 \times \left(1 - y_{jp}^B\right) DR_j \quad 1 \le j \le J, \quad 1 \le p \le P \tag{13}$$

Each PV and battery technology has a periodical fixed operation and maintenance (FOM) costs given by FOM_{ip}^{PV} and FOM_{jp}^{B}, respectively, during period p.

With these, all the required variables and constraints have been defined for calculation of the economic objective function which is the maximum net present value of overall savings in electricity costs over the planning horizon. The periodical amount of saving in the electricity bill is obtained by summing up baseline electricity costs with grid supply charges and subtracting FOM costs of PV and battery systems, and unserved energy costs. The sum of annualized discounted savings minus capital expenditures of PV and battery systems gives the objective function. This is given by

$$\begin{aligned} NPV = &- \sum_{i=1}^{I} \left(y_i CX_i^{PV} \right) - \sum_{j=1}^{J} \left(y_j' CX_j^{B} \right) \\ &+ \sum_{h=1}^{H} \left[\sum_{p=(h-1)P'+1}^{p=hP'} L_p EP_p + CF_p \right. \\ &\left. - \left(\sum_{i=1}^{I} \left(y_i FOM_{ip}^{PV} \right) + \sum_{j=1}^{J} \left(y_j' FOM_{jp}^{B} \right) \right) - USE_p FP_p \right] / (1+r)^h \end{aligned} \tag{14}$$

Where r is the discount rate. The first and second terms in Eq. (14) are total capital expenditures of PV and battery systems, respectively. The third and fourth terms are baseline cost of grid electricity and grid supply charges, respectively $\left(L_p EP_p + CF_p\right)$. The fifth and sixth terms are FOM costs for PV and battery systems, respectively; the last term is the penalty costs of unserved energy $\left(USE_p FP_p\right)$.

This equation completes the MILP (when inverter efficiency is constant) or MINLP (when inverter efficiency is a function of input power) model for the PV–battery planning problem. It consists of Eqs. (1)–(4) and Eqs. (6)–(13) with the objective of maximizing NPV (Eq. (14)). It is noteworthy that a battery-only system or PV-only system is a subset of the introduced formulation. When the system under study does not include either PV or battery, the relevant equations could be removed from the list and the program is executed with the remainder equations.

3. Results and discussion

3.1. Example 1

A house in Wahroonga, a Sydney suburb, has consumed within one financial year (July 1 to 30th June) about 8544.4 kWh of electricity with hourly profiles as per Fig. 3. The current electricity price consists of three ToU tariffs: (off-peak, shoulder, and on-peak). Off-peak (13 c/kWh) includes 10:00 pm to 7:00 am. Shoulder (21 c/kWh) is during 7:00 am–2:00 pm and 8:00 pm–10:00 pm on weekdays, and 7:00 am to 10:00 pm during weekend/public holidays. On-peak (52 c/kWh) period is during

2:00 pm–8:00 pm on weekdays (AGL, 2013). There is also a daily supply charge of \$0.87. With this electricity pricing scheme, the house spent \$2083.6 for its electricity bill over last financial year. Given such high electricity tariffs, which are amongst the most expensive ones in the world (Mountain, 2012), the consumer is interested to investigate the feasibility of installing a PV–battery system to leave the grid. For the sense of comparison, the model is allowed to select a system with grid independence values less than 100%. For such conditions, USE penalty values equal to the electricity tariff are considered.

There are multiple candidate PV systems with sizes in the range of 0–20 kW with standard efficiency of 0.17 (NREL, 2014). The periodical PV panels efficiency $\left(\eta_{ip}^{PV}\right)$ is affected by ambient temperature with a function of $1.09 - 0.0036 \times T_p$ (Fesharaki et al., 2011). The PV output also decreases by 0.5% annually (due to aging). The annual ambient temperature and GHI profiles are illustrated in Fig. 4a and b. There are multiple candidate Li-ion battery systems with sizes in the range of 0–50 kWh. If selected, the batteries will operate at a maximum DoD of 85% (Akhil et al., 2013). The charge controllers and inverters have an assumed constant efficiency of 98%. The batteries have charge and discharge duration of two hours and one hour, respectively. They have manufacturing round-trip efficiency of 92% (KEMA, 2012). The prices of PV systems are considered as \$3000 for a 1.0 kW system which follows a power-law economy of scale with power constant of 0.76 (Solar-choice, 2013). The unit cost of batteries (\$/kWh) are considered as \$1000 for a 1.0 kWh system with an escalation factor similar to PV systems (Jones and Zoppo, 2014). The annual maintenance cost of the PV system is 0.5% of its capex, while it is 1.0% for batteries.

The solar FiT is 8.0 c/kWh during the base year (IPART, 2013), but due to desire for disconnection from the grid, the house owner assumes to curtail the redundant solar generation. The annual price escalation factor is 3% with discount rate of 7% (Summers and Wimer, 2011). The consumer projects that their electricity consumption will increase by 0.5% annually over the next 10 years and would like to assess the economic practicality of installing a PV–battery system in order to leave the grid. If feasible, the specifications of the selected systems and their operation schedule are desired.

The optimization program (using CPLEX 12.4.0.1) suggests that there are no PV–battery systems in the given range that could bring 100% grid independence at a positive NPV within ten years following PV–battery system installation. This limitation is both technical and economical. Fig. 5 illustrates the impact of PV and battery sizes on the NPV. As evident from the figure, the highest NPV of saving is zero when there is no PV and battery installation. With addition of PV and or battery the NPV becomes negative.

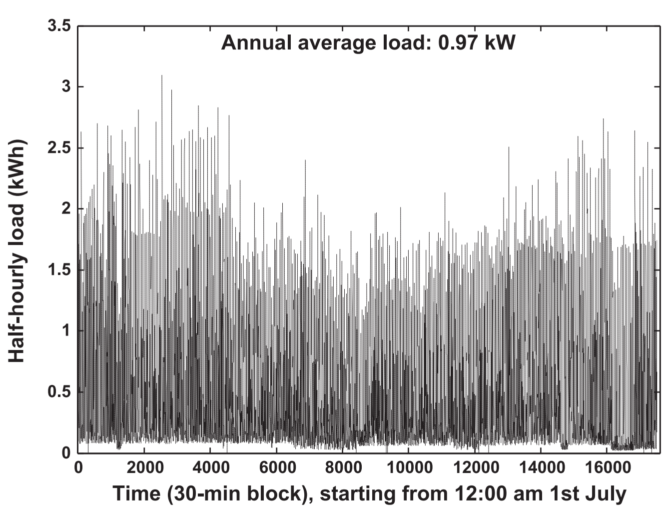

Fig. 3. The consumer's load profile during the base year.

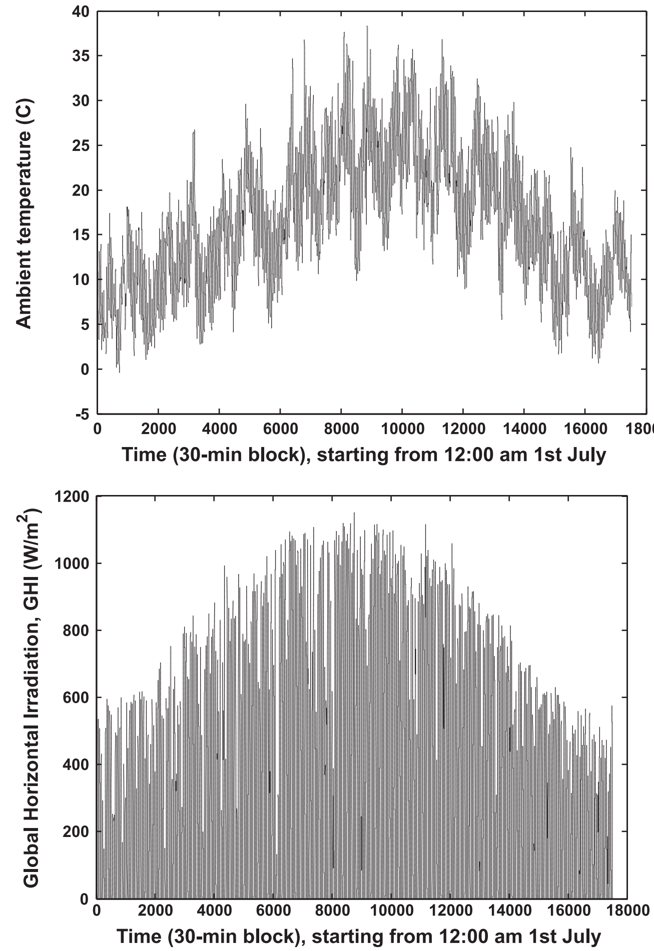

Fig. 4. Annual profile of weather at the consumer's location: ambient temperature (top) and GHI (down).

It is also noteworthy that, regardless of negative NPV, the PV size reveals an optimality at lower sizes (<5 kW) for any given battery size (Fig. 5). This could be explained by Fig. 6 which illustrates the grid independence of the house at any given configuration. It is evident from Fig. 6 that at any given battery size, by increasing the size of PV system, the grid independence reaches a maximum value and thereafter increases negligibly. For instance, for a PV-only system configuration, a 2.0 kW PV system will increase the house's grid independence from zero to 18.7%. A further increase in the size of the PV to 4.0 kW improves the grid independence by 20–22.4%. The independence increases marginally afterwards to be 26.1% and 28.0% at 10.0 kW and 20.0 KW PV sizes. As elaborated earlier, addition of a battery system is the key element in achieving high or complete grid independence. For instance, for a 2.0 kW PV system addition of a 2.0 kWh battery improves grid independence from 18.7% to 25.5%. For the same 2.0 kW PV system if a 10.0 kWh battery is utilized, the grid independence increases more than two-fold (40.4% versus 18.7%). A 10 kW PV-only system with a grid independence rate of 26.1% will have an independence rate of 60.3% if it is integrated with a 10 kWh battery system. With further increase in the battery size, it will have 75.4%, 94.8%, and 96.92% grid independence with battery sizes of 15 kWh, 30 kWh, and 50 kWh, respectively. With further addition of a 10 kW PV unit, to sum the PV system size at 20 kW, the grid independence rate improves less than 3% from 96.92% to

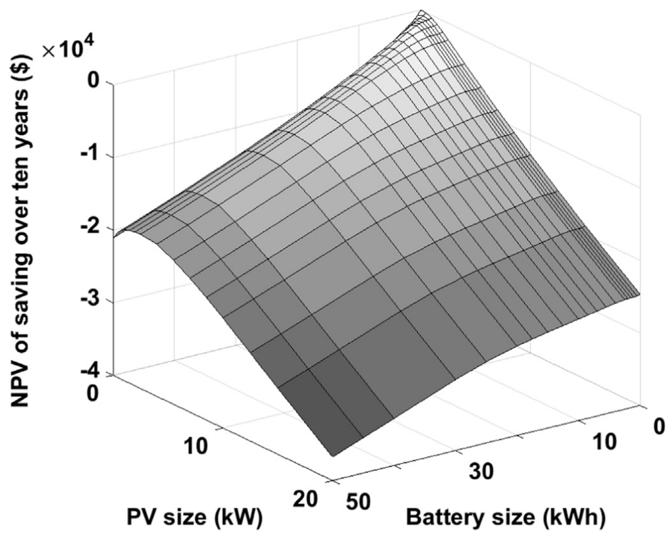

Fig. 5. Impact of PV and battery sizes on NPV of saving for the house (PV: 3000 $/kW, battery: 1000 $/kWh, economy of scale factor: 0.76, electricity price (c/kWh): 0.13 (off-peak), 0.21 (shoulder), and 0.52 (peak)).

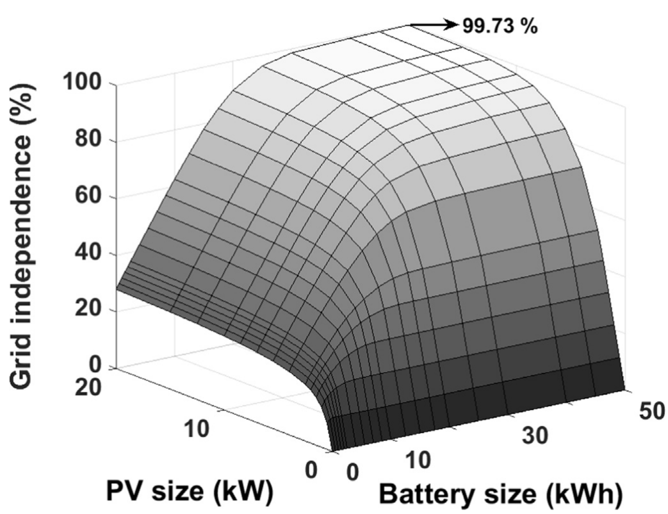

Fig. 6. Impact of PV and battery sizes on electric independence (PV: 3000 $/kW, battery: 1000 $/kWh, economy of scale factor: 0.76, electricity price (c/kWh): 0.13 (off-peak), 0.21 (shoulder), and 0.52 (peak)).

99.73% (maximum possible in the given range) with a 50 kWh battery system.

Fig. 7 illustrates the percentage of unused PV generation curtailed at any given configuration. It is evident from the figure that the unused PV output escalates as the PV size increases at any given battery size. However, for any given PV size, with the addition of a battery, the PV utilization improves (UUE % declines). For instance, 35.9% of a 1.0 kW PV system will be unused in the absence of any battery. This value will be 57.6% for a 2.0 kW PV and 74.6% for a 4.0 kW PV size. About 93.6% of the output of a 20 kW PV-only system will be unused.

The UUE percentage declines, when a battery is integrated with the PV system. For instance the redundant energy of the same 1.0 kW PV system will decline from 35.9% with PV-only to 11.0% with a 2.0 kWh battery. A 10 kWh battery system will reduce the unused energy of a 1.0 kW PV system to zero. It is also evident from Fig. 7, that for any given PV system, with an increase in battery size, the UUE percentage declines fast and reaches a plateau at certain battery size above which the size increase has negligible impact on UUE percentage. For instance, for a 4.0 kW PV system, the UUE percentage declines notably from 74.6% (without

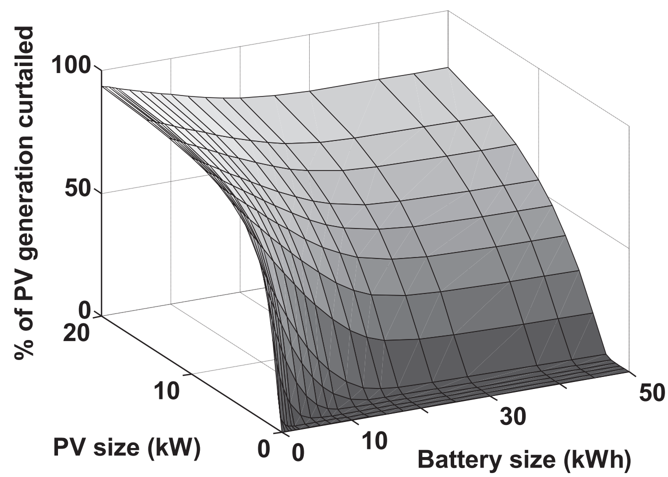

Fig. 7. Impact of PV and battery sizes on curtailed energy (PV: 3000 $/kW, battery: 1000 $/kWh, economy of scale factor: 0.76, electricity price (c/kWh): 0.13 (off-peak), 0.21 (shoulder), and 0.52 (peak)).

battery) to 37.4% with a 10 kWh battery. A further addition of 10 unit battery size, reduces the UUE percentage to 18.0% at 20 kWh size. However, afterwards, with another 20 kWh increase of the battery size to 40 kWh, the UUE % only drops slightly to 14.9%. The negligible impact of battery size after a certain range is due to the fact that the house needs a limited amount of energy storage to supply its demand till tomorrow morning when PV restarts electricity generation. Therefore, extra-storage of electricity will cause more UUE the next day.

In summary, neglecting the economics and only from technical perspective, it is evident from Fig. 6 that leaving the grid (100% grid independence) requires relatively very large PV and battery systems. For instance, the highest grid independence value for the house of the study is found to be 99.73% for the maximum size in the range (20 kW PV and 50 kWh battery) with an NPV of −$39,861.5. This implies that 100% grid independence needs larger PV and/or battery systems at high installation costs. In addition, a large PV–battery system will have a significant amount of unused PV output to curtail (Fig. 7). For instance the 20 kW/50 kWh PV–battery system will curtail 76.6% of its PV output. This translates to around 28,962.6 of net AC power (after inverter) which, if sold with FiT of 8.0 c/kWh, could bring extra income of $2317.0 for the house just in the first year of operation. Therefore, at the given technology costs and with the discussed electricity tariff (which is one the most expensive and thus attractive ones in the world), leaving the grid might not be the right option for this house.

3.2. Example 2: impact of consumption load

Example 1 pertained to a house with an annual load of around 8.54 MWh (hourly average of 0.97 kW). Here, we also study two other houses which are in higher and lower extremes in terms of consumption quantity. The load profiles of the two houses are illustrated in Fig. 8. House A has consumed 13.44 MWh (hourly average of 1.53 kW) during the base year while the value for house B is only 2.99 MWh (hourly average of 0.34 kW). The annual average daily load profiles of house A and B are also illustrated in Fig. 9. The figure shows that both of the houses have a short morning peak and a larger afternoon peak.

The optimization results for the two houses are illustrated in Fig. 10. As evident from the figure, house B, with a relatively low annual load, does not have a positive NPV (payback time less than ten years) over the wide range of PV and battery sizes. However, house A, with a high annual load, shows some positive NPV with

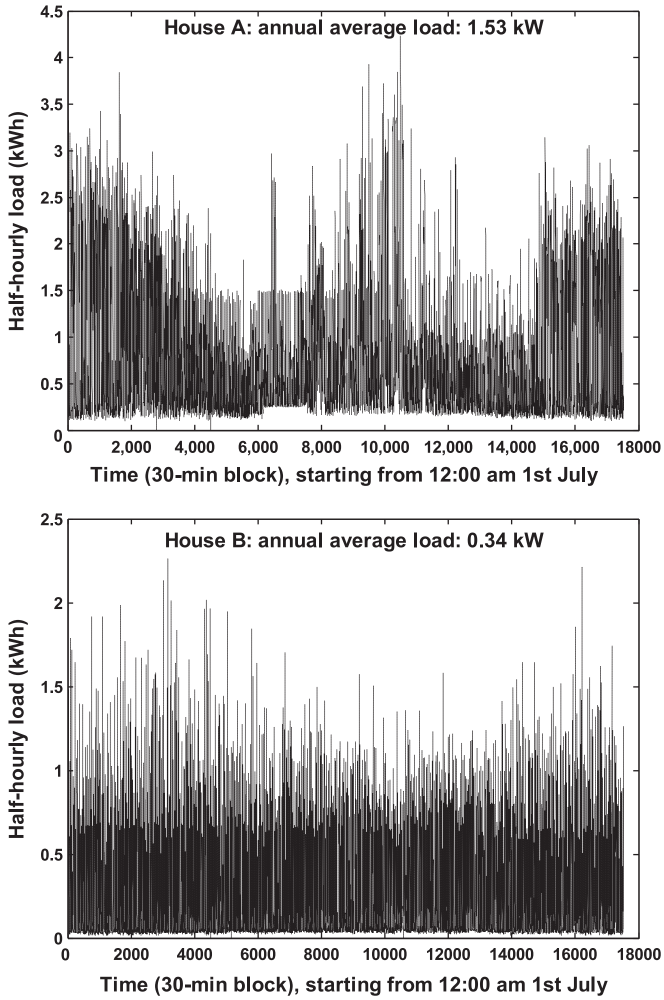

Fig. 8. The load profile of house A and B during the base year.

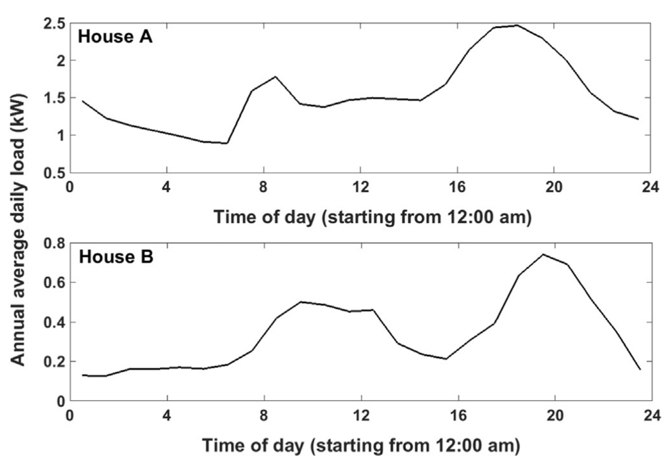

Fig. 9. The annual average daily load profile of house A and B during the base year.

small PV and battery systems. The maximum NPV for this house is with a 1.5 kW PV-only system being around $895 over the first 10 years of operation. Needless to mention that a small-scale system is unable to satisfy the house's grid independence.

Fig. 10 also illustrates the grid independence of both houses. House *A*, never reaches grid independence over the given wide PV/battery ranges. The largest configuration in the list (i.e. a 20 kW PV with a 50 kWh battery) can only secure 98.1% independence. House B, however, could reach 100% grid independence in part of the range. With a 5.5 kW PV, house B reaches 99% grid independence with a 8.5 kWh battery, whereas achieving the remainder 1% independence, to 100%, requires another 36.5 kWh battery, totaling 45 kWh. With a 20 kW PV system, the 99% independence will require a slightly smaller battery system with size of 7.0 kW, while 100% grid independence still requires a 45 kW battery system.

For obvious reasons the graph of unused PV output versus PV–battery size should show more sensitivity for a house with higher local consumption. Fig. 10 shows that for house *A* at any given PV size, the curtailed percentage declines with an increase in battery size. The battery system saves surplus PV output to supply the house's demand when PV output is unavailable. However, when the local demand is low, as for house B, storage of PV output above the house demand would be useless. For instance, with a 4.0 kW PV-only system, house B will have 82.9% UUE. With addition of a battery system this value continuously declines until becoming 60.0% with an 8.5 kWh battery system. From this size onwards the curve reaches a plateau and with increasing the battery size by more than five folds to 50 kWh the UUE percentage only drops 0.7 point to 59.3%. For a larger PV system this situation is more severe. The UUE percentage of a 20 kW PV-only system is 96.1%. With a 50 kWh battery this drops only 4.4 points to 91.7%.

In summary, for the given conditions for a high-load house it is economically feasible to invest in a small PV–battery system, however this does not guarantee 100% grid independence. Like Example 1, leaving the grid requires a significantly large PV–battery system which is not economically justifiable. A low-load home though requires a smaller PV–battery system for achieving full grid independence (relative to a high-load house), still is not economically feasible due to the lower saving in electricity costs compared with the initial investment.

3.3. *Example 3: impact of feed-in tariff*

Fig. 6 shows that a high level of grid independence requires a large PV–battery system which ultimately needs to curtail significant amounts of unused PV output (Fig. 7). Here we use three different feed-in tariff values (4, 8, and 12 c/kWh) to investigate how much the home could earn from selling its surplus PV output if it was connected to the grid. We also consider two different grid supply charge of 300 and 600 $/y.

The results are illustrated in Fig. 11. For a FiT of 4 c/kWh, a PV-only system will have a potential annual saving of $300+ at sizes above 5.0 kW from the unused PV generation (UUE) during the first year of operation. PV systems with sizes greater than 9.0 kW have a potential of $600+ income from the FiT. The income from UUE increases with higher FiTs. For instance, at a FiT of 12 c/kWh, a small 2.5 kW PV-only system is able to make $300/y. A 4.0 kW PV system can earn $691/y from the FiT.

Obviously, when the battery is included, the amount of UUE reduces. For instance, a standalone 4.0 kW PV system generates 5640.2 kWh/y ($451.2/y income at FiT=8 c/kWh) of UUE for the given house. However, this reduces to 5300.1 kWh/y with a 1.0 kWh battery ($424.0/y income at FiT=8 c/kWh), to 4398.2 kWh/y with a 4.0 kWh battery ($351.9/y income at FiT=8 c/kWh), and ultimately to 1090.3 kWh/y with a 50 KWh battery ($87.2/y income at FiT=8 c/kWh).

For relatively large PV sizes, even a 50 kWh battery is unable to prevent significant amounts of UUE from curtailment. For instance, a 10 kW PV system generates 10,309.6 kWh/y of UUE with a 50 kWh battery ($824.8/y income potential at FiT=8 c/kWh). At 20 kW PV and the same 50 kWh battery configuration, the UUE will increase to 28,962.6 kWh/y ($2157.0/y income potential at FiT=8 c/kWh).

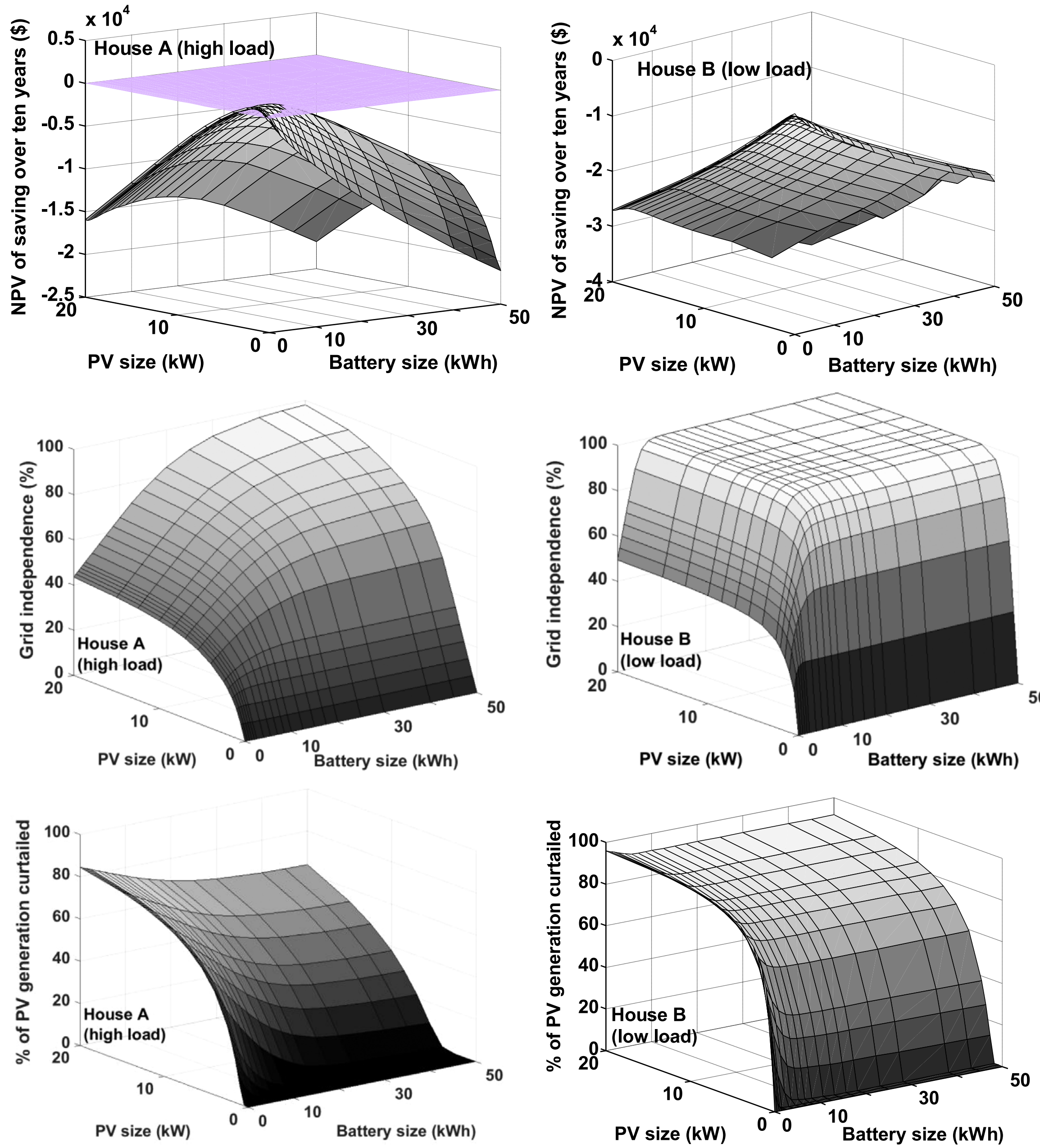

Fig. 10. Impact of load quantity and PV/battery sizes on NPV (top), grid independence, and curtailed energy (PV: 3000 $/kW, battery: 1000 $/kWh, economy of scale factor: 0.76, electricity price (c/kWh): 0.13 (off-peak), 0.21 (shoulder), and 0.52 (peak)). House A (left) with high load, and house B (right) with low load.

In summary, it is evident that there exists a conflicting condition. A small PV–battery system is less costly, but is unable to satisfy a higher percentage of grid independence. Therefore, it implies grid-connection is necessary. On the other hand, a relatively large PV–battery system could satisfy grid independence (neglecting its notably high installation costs). However, according to Fig. 11, such a system will have a very high UUE which could be a revenue source a few-fold higher than the annual grid connection fee (supply charge). Therefore, considering the economic advantage of grid-connection for selling the surplus energy, grid disconnection might not be the best option. This recommendation will be stronger as PV–battery installation costs decline over time.

3.4. Example 4: impact of technology costs

This is similar to the previous Example 1, but here we desire to investigate the impact of the probable reduction of technology installation costs on the feasibility of installing PV–battery systems.

In the previous example, negative NPV values were found for systems with PV and battery prices of 3000 $/kW and 1000 $/kWh, respectively (both with economy of scale). Here, we study the impacts of PV prices, in the range of $1600–3000, and battery prices, in the range of $400–1000, on the economic feasibility of leaving the grid.

Fig. 12 illustrates the NPV results at nine different combinations of PV and battery price bases. As evident from the figure, except two of them, in all of the other scenarios the NPVs are negative over the entire range of PV and battery sizes. Overall, Fig. 12 suggests that batteries are not a feasible option at the base costs of 700–1000 $/kWh. However, at battery prices of 400 $/kWh when the PV prices are in the range of 2300 $/kWh or less, there could be found some PV–battery sizes with which the house could have positive NPV. For instance Fig. 13 illustrates the sweet spot of PV

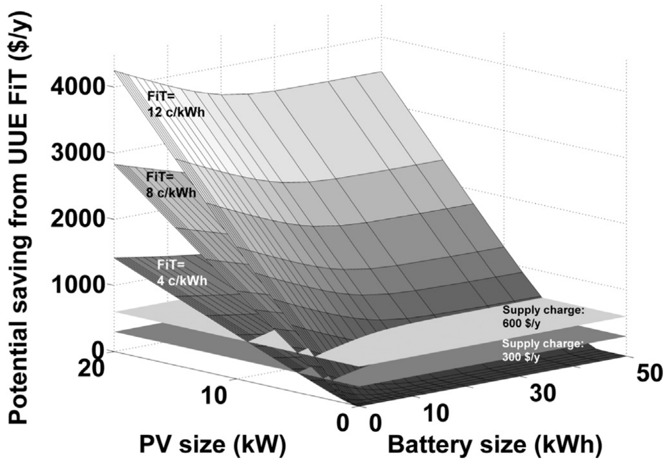

Fig. 11. Interaction between PV–battery size, feed-in tariff and grid supply charge (PV: 3000 $/kW, battery: 1000 $/kWh, economy of scale factor: 0.76, electricity price (c/kWh): 0.13 (off-peak), 0.21 (shoulder), and 0.52 (peak)).

and battery sizes at two base price configurations of (a) 1600 $/kW PV and 400 $/kWh battery and (b) 2300 $/kW PV and 400 $/kWh battery.

At scenario a, a PV system with size within 1.5–3.0 kW will have a positive NPV within the entire battery range of 0.5–15 kWh. For larger PV systems (>3.0 kW), only relatively large batteries make the NPV positive (mainly due to the economy of scale). For instance, while a 4.0 kW PV system will have a positive NPV with a 1.0+ kWh battery, a 7.0 kW PV system will have a positive NPV with a 10.0+ kWh battery. Larger PVs (>7 kW) will not have a sweet spot alone or with any combination of batteries. The highest NPV of scenario *a* is $2354.1 for a system with a 2.0 kW PV and 5.5 kWh battery. Such a system will provide grid independence of 34.2% during the first year of operation with 20.5% of its PV output curtailed.

Scenario *b* which is at higher PV price (2300 $/kW), obviously encompasses a smaller region as sweet spot. The maximum NPV for this scenario is $1262.0 with a 1.5 kW PV and a 4.0 kW battery systems.

3.5. Example 5: impact of geography

The feasibility of renewable technologies is critically dependent on the location's richness in terms of the energy resources (e.g. GHI for PV and wind speed for wind turbine). Here, we investigate the impact of location on the viability of leaving the grid. We study a house which has an annual load of 6.1 MWh. The consumer's hourly load profile during the base year is illustrated in Fig. 14.

We have selected three locations with low to high GHI. The first location is Hobart (with latitude of -42.8 and average annual GHI of 1.40 MWh/m^2), the middle location is Sydney (with latitude of -33.9 and average annual GHI of 1.67 MWh/m^2). The richest location in terms of irradiation is Alice Springs (with latitude of -23.8 and average annual GHI of 2.25 MWh/m^2).

Fig. 15 illustrates the NPV and grid independence profiles of these scenarios. The NPV profiles in Fig. 15 (top) are based on PV costs of 1500 $/kW and battery costs of 500 $/kWh. The sweet spot of NPV curves (NPV ≥ 0) are illustrated in Fig. 15 (middle). The impact of location is obvious from the figures, as with the increase of absolute latitude the positive NPV region shrinks. For instance, for the house of study in Alice Springs, a 4 kW PV system will have positive NPV with battery sizes less than 35 kWh. In Sydney, however, a 4 kW PV system has positive NPV only for batteries smaller than 28 kWh. The feasibility range becomes even narrower for Hobart, for which only batteries smaller than 23 kWh are feasible with a 4 kW PV system.

Although the above discussion quantitatively shows the advantage of low-latitude locations, full grid independence is infeasible for all of the three locations for the houses modeled. In Hobart, the maximum NPV ($1970.8) is achievable with a 4 kW PV and 8.5 kWh battery, which brings only 60.9% grid independence for the house. The maximum grid independence (with zero NPV), is achievable with an 8.5 kW PV and 14 kWh battery system to be 82.3%. For Sydney, the maximum NPV becomes $2776.1 with a 2.5 kW PV and a 7.0 kWh battery, which brings 53.6% grid independence for the house. The maximum grid independence (with zero NPV), is achievable with a 7.0 kW PV and 22.5 kWh battery system to be 89.7%. For Alice Springs, the maximum NPV becomes $4071.7 with a 2.5 kW PV and an 8.5 kWh battery system, which brings 52.1% grid independence for the house. The maximum grid independence (with zero NPV), is achievable with a 7.0 kW PV and 25 kWh battery system to be 93.5%. Interestingly, full grid independence is not even achievable in the maximum PV–battery size studied here. A 20 kW PV and a 50 kWh battery systems results in 99.6% autonomy to the cost of reasonably low NPV ($-$\$11,893.5).

Therefore, though location (and thus GHI) has a notable impact on the size and performance of a PV–battery system, full grid independence for leaving the grids is not a feasible option even at high-GHI locations like Alice Springs, for the selected homes.

4. Conclusion and policy implications

With the observed fast reduction of PV and battery system prices in recent years, interest in the use of PV–battery systems has significantly increased. The technology transformation underway at the demand-side has not stopped. The projection for continuous reduction in PV prices and a similar trend for battery storage has prompted considerable public interest and excitement for "leaving the grid" or "living off-grid" in order to dissociate from the risk of increasing electricity tariffs. This is described as a "death spiral" for utility industries.

The key assumption of the death spiral is that when some of the customer base are transformed to prosumers and leave the grid, the network cost will be distributed over fewer customers and thus the electricity prices will increase. The consequent rise of electricity prices will further improve the economic attractiveness of leaving the grid for the remaining customers and will expedite grid defection. This loop will continue like a spiral until collapsing the utility industry. The fear from leaving the grid has been increasing to an extent that it has recently been a separate scenario in the policy studies for future grids.

In order for rigorous analysis of this phenomenon, we developed a multi-period mixed-integer linear program (MILP) with the objective of finding the most economical decision of customers over the planning horizon. The summary of the results is illustrated in Fig. 16. The analyses show that a small PV–battery system has the highest NPV, but also has the highest amount of unserved energy. Therefore, such a system is unable to serve all of the demand required for grid independence.

By increasing the size of the PV system, with still a small battery, the grid independence level increases to some extent, but not significantly. As such, though a larger PV system reduces the NPV, the consumer will not be able to achieve the grid-disconnection goal. A large battery, obviously, plays a key role in increasing the grid independence level. With a small PV size, a large battery is able to increase the consumer's grid independence level though at low NPV. Nevertheless, 100% grid independence is only possible with a very large PV–battery system which is subject to significant capital costs.

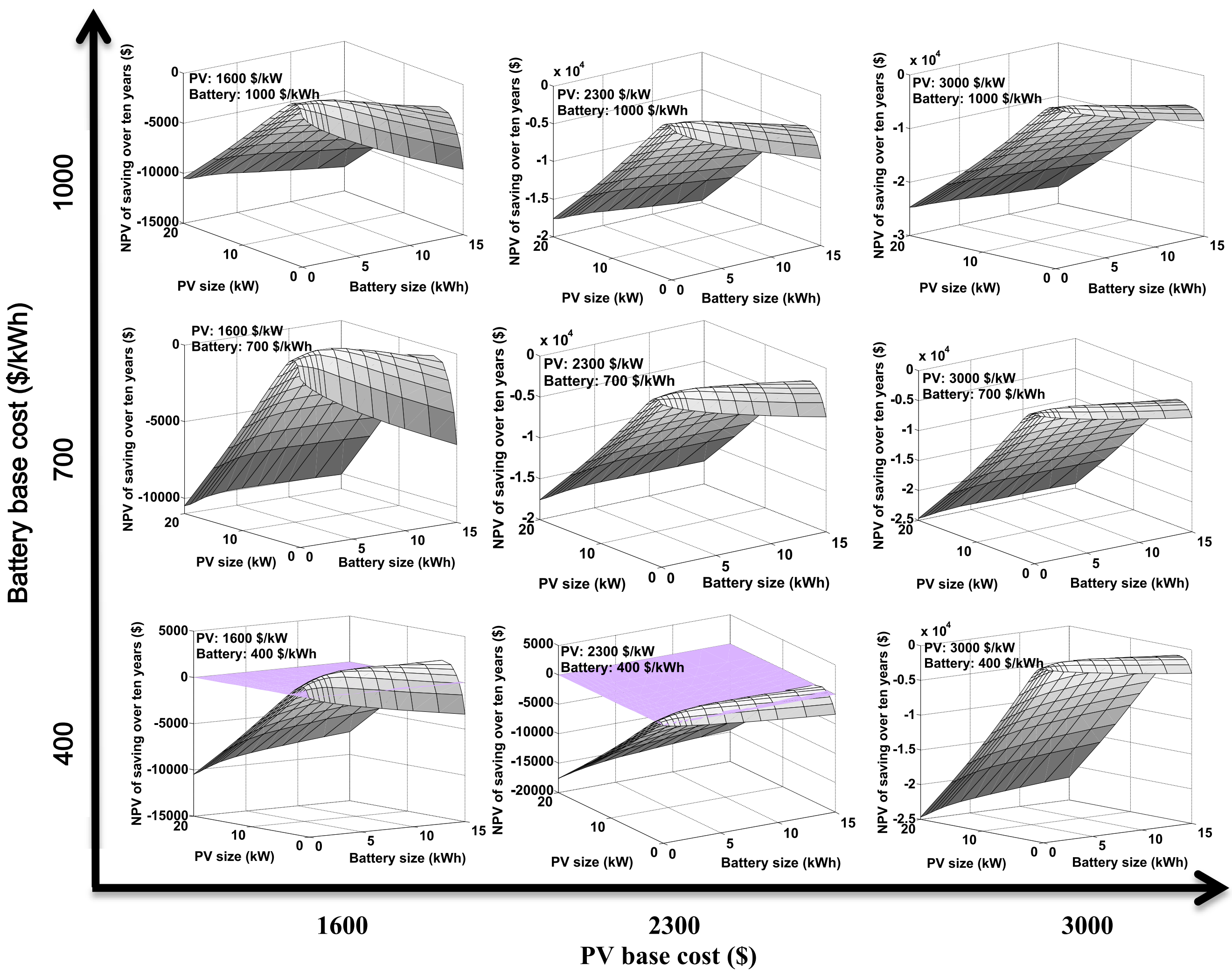

Fig. 12. Impact of PV and battery installation costs on the feasibility of leaving the grid (economy of scale factor: 0.76, electricity price (c/kWh): 0.13 (off-peak), 0.21 (shoulder), and 0.52 (peak)).

The results of this study imply that leaving the grid is not a feasible option even at low PV–battery installation costs, at least for the types of household electricity consumption and demand profiles used in this study. Moreover, the analysis (e.g. Fig. 11) shows that the benefit of grid connection in terms of revenue from FiT of the unused energy is notably high when a large PV system is installed. It might be more beneficial to keep the connection to the grid, but minimize the electricity purchase through installation of an optimal size of PV–battery system.

In summary, the policy implication of this limited study is that

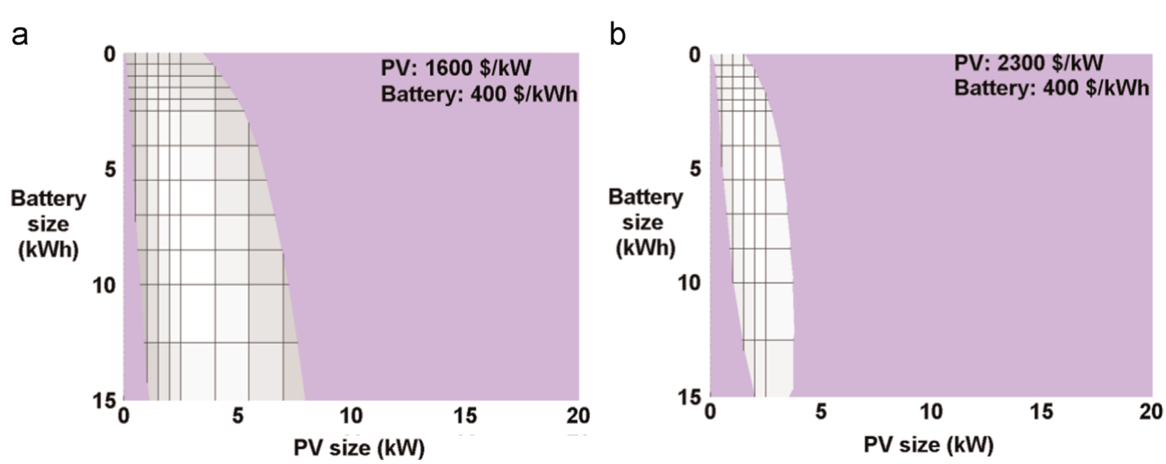

Fig. 13. Sweet spot of PV–battery sizes at technology costs of (a) 2300 $/kW PV and 400 $/kWh battery and (b) 1600 $/kW PV and 400 $/kWh battery (economy of scale factor: 0.76, electricity price (c/kWh): 0.13 (off-peak), 0.21 (shoulder), and 0.52 (peak)).

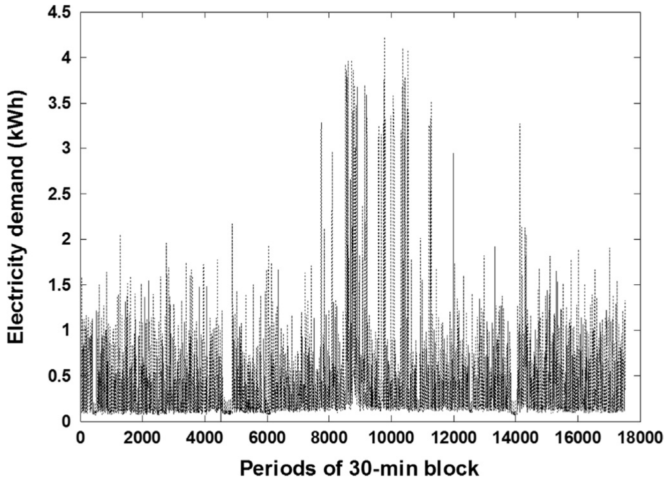

Fig. 14. The consumer's load profile during the base year (Example 4).

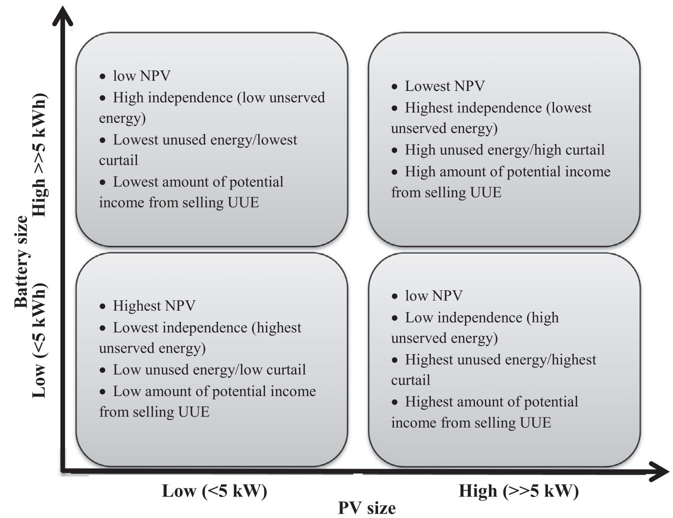

Fig. 16. Impact of PV and battery sizes on the NPV, independence level, unserved energy, and unused energy.

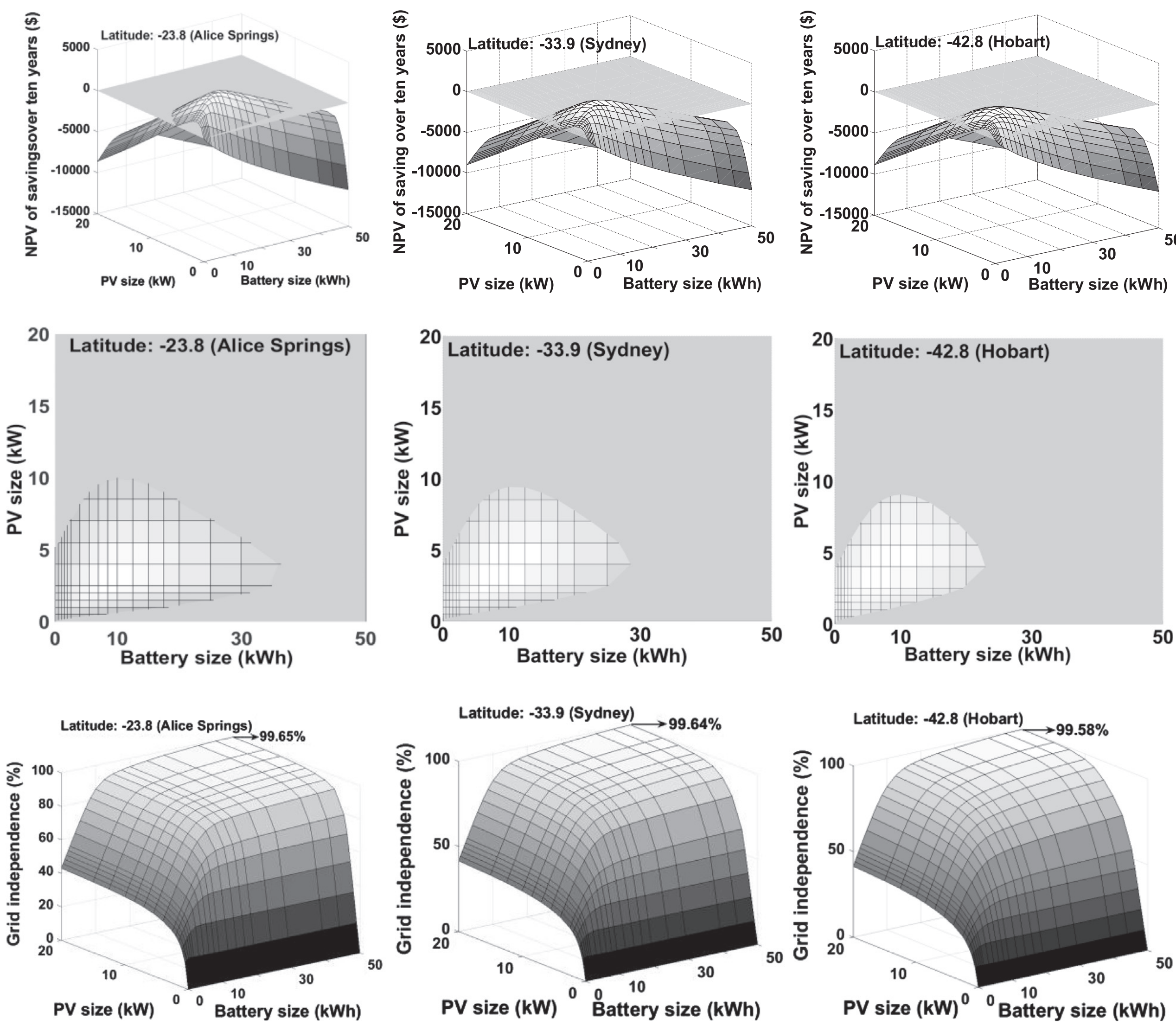

Fig. 15. Impact of location on NPV (top), NPV sweetspot (middle), and grid independence (below) (PV: 1500 $/kW, Battery: 500$/kWh, economy of scale factor: 0.76, electricity price (c/kWh): 0.13 (off-peak), 0.21 (shoulder), and 0.52 (peak)). Hobart (left) with low GHI, Sydney (middle) with medium GHI, and Alice Springs (right) with high GHI.

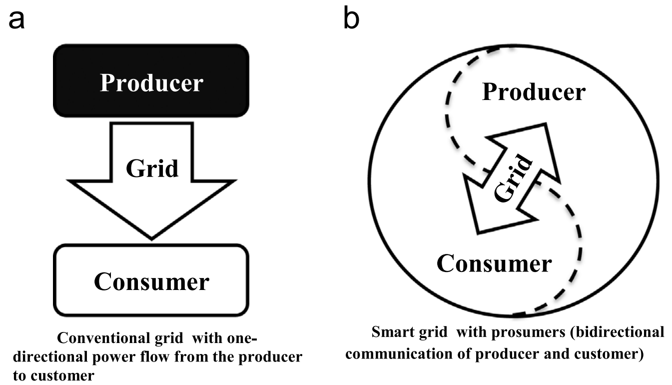

Fig. 17. Conventional one-directional grid versus the bidirectional smart grid of prosumers. Electricity community is well familiar with the concept of AC (alternating current). The new AC is "alternating consumers" which alternates within consumer–producer range during a day.

leaving the grid in a widespread scale might not be a realistic projection of the future, if economics is assumed as the main driver of customer behavior. Rather, a significant reduction of energy demand per connection point is a possible option when the PV–battery prices decline.

It could be projected that while the conventional grids were one-directional networks of producers-to-consumers, the future grids will be a bidirectional network of prosumers which are sometimes producers and some-times consumers (Fig. 17). Therefore, policies could be devised to help electricity network operators develop other sources of revenue from future small-scale prosumer contracts by devising smart tariffs and DSM mechanisms rather than only increasing the energy prices assumed to be the driver of death spiral. These policies should be designed to maximize the network benefits of PV–battery systems, such as through fair compensation for generation and/or load reduction during critical peak times and/or encouragement for consumers to install such systems in locations where network augmentation may be required.

Acknowledgments

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