ORIGINAL RESEARCH

Numerical simulation analysis of the impact of photovoltaic systems and energy storage technologies on centralised generation: a case study for Australia

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Abstract

In response to climate change concerns, most of the industrialised countries have committed in recent years to increase their share of Renewable Energy Sources to reduce Greenhouse Gas emissions. Therefore, the rapid deployment of small-scale photovoltaic (PV) systems, mainly in residential applications, is starting to represent a considerable portion of the available electrical power generation and, for this reason, the stochastic and intermittent nature of these systems are affecting the operation of centralised generation (CG) resources. Network operators are constantly changing their approach to both short-term and long-term forecasting activities due to the higher complexity of the scenario in which more and more stakeholders have active roles in the network. An increasing number of customers must be treated as prosumers and no longer only as consumers. In this context, storage technologies are considered the suitable solution. These can be necessary in order to solve and fill the problems of the renewable distributed sources are introducing in the management of the network infrastructure. The aim of this work was to create a model in order to evaluate the impact of power generation considering PV systems in Australia along with a model to simulate Battery Energy Storage Systems (BESSs) and Electric Vehicles future contributions using MATLAB. The methodology used to develop these models was based on statistical assumptions concerning the available details about PV systems installed and current storage technologies. It has been shown that in all the scenarios analysed, the future adoption of rooftop PV panels and impact on the CG is incredibly higher than the uptake of energy storage systems. Hence, the influence on the demand will be driven by the behaviour of the PV systems. Only in the hypothetical scenario in which the installations of BESSs will assume comparable levels of the PV systems, it will be possible to better manage the centralised resources.

Keywords Photovoltaic system (PV) · Battery energy storage system (BESS) · Electric vehicles (EVs) · Distributed generation (DG) · Centralised generation (CG)

Abbreviations

ABS	Australian bureau of statistics
AEMC	Australian energy market commission
AEMO	Australian energy market operator
AER	Australian energy regulator
APVI	Australian photo-voltaic institute
BESS	Battery energy storage system
BRICS	Brazil Russia India China South Africa
CEC	Clean energy council
CG	Centralised generation
COP	Convention of the parties
CPRS	Carbon pollution reduction scheme
DG	Distributed generation
DNSP	Distribution network service provider
ESRA	European solar radiation atlas
EV	Electric vehicle
GDP	Gross domestic Product
GSL	Guaranteed service level
IPSS	Integrated photovoltaic storage system
NEFR	National electricity forecasting report
NEL	National electricity law
NEM	National electricity market
NSW	New South Wales

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OECD	Organisation for economic co-operation and development
PV	Photo-voltaic
RES	Renewable energy source
RET	Renewable energy target
TOU	Time-of-use tariff_
UNFCCC	United Nations framework convention on climate change

Introduction

The integration of residential renewable generation technologies, such as rooftop solar photovoltaic (PV), into electrical distribution networks, continues to grow and is expected to be unstoppable for the next decades, before the saturation point is reached [1–3]. Rooftop PV systems generation is a valid reply to climate change as it can decrease greenhouse gas emissions. These Distributed Generation (DG) systems are starting to represent a portion of the available electrical power generation to the extent that demand, as seen from centralised generation resources, is beginning to decline [4–6]. The demand reduction during central hours of the day is the characteristic signature of the PV generation. This has an impact on the operation of centralised resources from both a technical and economic perspective [6–9].

Climate change and its effects are now recognised as some of the most significant threats humanity has to challenge to guarantee a future health and prosperity of our planet [10]. The effects of this unstoppable climate variation are starting to involve not only weather and the environment (as flora and fauna) but social, economic and development aspects are threatened as well. Scientists' works have identified some specific human activities are having a massive impact on the recent climate change, often known as 'global warming'. Carbon dioxide concentration increase has been detected as the major anthropogenic contributor to climate change. The intensity of the impact depends not only on the magnitude of the change but also on the potential of irreversibility. CO_2 concentration is largely irreversible and 1000 years is at least the minimum period necessary to register a substantial drop after emissions stop [11]. Every country is now affected, but on the one hand, strong economies and industrialised countries have till now contributed to aggravate the situation; on the other hand, underdeveloped and poorest countries are the most being affected. Several factors contribute to the total greenhouse gases emissions, electricity generation, concrete industry, transport and chemical sector are its representatives.

These activities are the reason why developed and developing economies were required to adopt a package of responses to contrast the increase of this phenomenon. Several organizations and institutions play a key role in developing sustainable strategies to preserve biodiversity and guarantee next generations an adequate access to natural resources. The United Nations Framework Convention on Climate Change (UNFCCC), entered into force in 1994, aims at reducing greenhouse gases concentration. The Conference of the Parties (COP) was designed as the supreme governing body of the Convention and its roles are to confer every country differentiated responsibilities to develop adequate national strategies for addressing the issue, as well as determining technological and financial support to emerging countries. The Paris agreement during COP21 at the end of 2015 established reduction of emissions as part of the method to keep global warming global warming "*well below 2 "C"* [12] and mitigate the carbon dioxide concentration. In response to climate change concerns, most of OECD' (Organisation for Economic Cooperation and Development) and BRICS' (Brazil Russia India China South-Africa) countries governments' committed to increase the amount of share of renewable energy as the first and quickest solution to mitigate this threat.

Electricity generation contributes to 38% of Australia's emissions and, in particular, coal-fired power stations accounted for 54% of registered capacity in the National Electricity Market (NEM) and supplied 76% of output in 2014–15, dropping from 85% of 2012 [13]. The massive presence in Australia of large centralised coal-fired power stations is the combined result of the abundant resources of fossil fuels and the big effort in investment done in 1980s to attract high-energy intensive industries. The Australian Government proposed in 2009 an implementation of the Renewable Energy Target (RET), introduced in 2001, and an emissions trading scheme—the Carbon Pollution Reduction Scheme (CPRS). The Commonwealth Parliament approved the national target increase to 45,000 GWh, more than four times the pre-existing target, determining so that 20% of Australia's electricity generation to come from RES (Renewable Energy Sources) by 2020. By 2030, expiring date of the scheme, the CPRS is intended to sufficiently stimulate renewable energy sector. As a result of the RET, Australian Government announced a minimum target of 5% reduction in emissions (based on 2000 levels) by 2020, with the possibility to extend the target to 25% in case of coordinated and cooperative international actions. In August 2015, the RET was modified and the target was set at 33,000 GWh; the amendment was a compromise brokered with the Clean Energy Council (CEC) as a consequence of 15 months of lost investment, caused by a review of the policy, and the recent softening of the electricity demand. Energy efficiency, reduction in electricity consumption, the planned increasing penetration of RES, the transition to a higher share of gas in electricity generation form part of the Australian suite of responses needed to shift to a low-carbon intensive economy.

The challenges, that the energy sector is now facing, are negligible compared to the future challenges that have to be faced if one considers how disruptive the uptake of this technology is. A rapid structural reform of the market, reinvent the business model used till now, a new way to use the energy and new directions of the future investments are some of the main changes that all the stakeholders have to considered in this scenario. The intermittent and stochastic nature of renewable energy generation means that energy storage technologies are required to better manage generation and consumption in distribution networks. From the technical point of view, the presence of a massive number of PV systems and the future adoption of storage technologies as Battery Energy Storage Systems (BESSs) and Electric Vehicles (EVs) in distribution grids are amplifying the complexity and uncertainty of demand forecasting models, making network operators incur into huge additional costs when frequent unbalances occur [14–18].

Although photovoltaic systems and energy storage technologies for use in buildings and in industrial applications were intensively investigated mainly in terms of load management and peak shaving [19–22], the prediction of the impact of photovoltaic systems [22–26], energy storage technologies and EV interaction on centralised generation is somewhat less explored, due to their complexity involving many parameters and control strategies [27–39].

This work aims to investigate the current and future impact of distributed photovoltaic systems and energy storage technologies, connected to low-voltage network, on the centralised generation archetype. In this regard, an Australian case study has been considered in this work. To achieve this, a model to evaluate the PV contribution deriving from the aggregation of all the distributed systems and a model to analyse the future support and impact of BESSs and EVs are developed. The reminder of the paper is organised as follows. Section 2 presents details on data collection and pre-processing for assessing the impact of photovoltaic systems and future storage systems installation on centralised generation. Section 3 gives the methodology for analysing the electricity demand evolution and provides the results of the electricity demand profile in New South Wales and whole NEM regions for different weather and season conditions. Section 4 provides the full details of the mathematical PV and BESS developed models and Sect. 5 presents the results of simulation and a discussion. Finally, the last section summarises the work.

Data collection and pre-processing

Distribution networks deliver and transmit electricity from high-voltage transmission lines to low-voltage residential and business customers. Australia has 850,000 kilometres of distribution network; 17 times longer than the transmission infrastructure [40]. All these networks are capital intensive and benefit from economies of scale as marginal costs decline with an increment of output, achieving so a condition of natural monopoly. The legislation and the stakeholders involved in this framework are many. The Australian Energy Market Commission (AEMC) has rule making and market development functions under the National Electricity Law (NEL) [41]. The NEL is applied in each participating jurisdiction of the National Electricity Market (NEM) with the help of the National Electricity Rules (NER) that govern and regulate the operations of the networks in the NEM to ensure non-monopolistic price behaviour and guarantee a reliable, efficient and safe level of the supply service. The Australian Energy Regulator (AER), recognising the risk of inadequate investments in maintenance and augmentation of the network because of distribution operators' attempts to save money, introduced, in parallel with the existing legislation, several measures such as an incentive scheme [42]. The scheme's framework is structured to stimulate the distribution business to achieve performance targets with the aid of a Guaranteed Service Level (GSL) component. GSL represents a standard quality limit that makes operators incur into financial bonuses or penalties of up to 5% of revenue in case they meet or fail to meet the established level [43].

Considering the increasing penetration of unpredictable small-distributed generation systems, network planners have to carefully plan the strategies necessary to maintain a high reliability level, reduce the risk of outages and control the supply stability. In the work, all the discussion is focused on New South Wales (NSW). The decision to analyse and illustrate the results only for NSW and not another state or all of Australia is due to different considerations. First, Australia is one single country but the transmission network, and consequently the centralised generation, is divided into different states and markets due to its very extensive geographic surface. Thus, it is more accurate and more significant to show the result for an individual state. Second, NSW represents the state with the largest population in Australia, with the highest population density and with the highest penetration of PV systems. Thus, it is more representative of the variety of the applications considered (big city, outback, coast villages, etc.). Third, the current profile and the characteristics of the evolution of the electricity demand in NSW are specular to that one of all the NEM's states aggregated. In addition, the purposes of this work are to provide a new approach or methodology that can flexibly be adapted to the different states and to different data sets.

Assessing the impact of photovoltaic systems and future storage systems installation on centralised generation requires several sets of data, because of the complexity and the huge number of factors, which can modify the effect that distributed generation has on electricity network [44, 45].

Australia is experiencing a rapid uptake of rooftop PV systems and almost all of them are not directly metered. It is a common practice for utilities measure only the net energy injected into the grid or absorbed from the grid, as the tariff structure is set on the net flow of energy exchanged. The evolution of the tariff is going toward the direction of a *feed-in-tariff*, which requires a second meter, used to measure the power generated from PV system. In addition to this economic aspect, there is also the need for an accurate generation forecasting, as the continuous penetration of rooftop PV systems is becoming a significant part of the total generation capacity into the NEM infrastructure. Therefore, a solid and accurate model of the generation from aggregated rooftop PV systems allows understanding past generation and can help in forecasting activities.

Electricity demand evolution

Forecasting electricity demand is becoming harder due to its dependency on a wide range of factors and of the different impacts from customers' behaviour. The increasing penetration of unpredictable renewable sources in distribution grids is amplifying the complexity and uncertainty of forecasting models, making network operators incur into huge additional costs when frequent unbalances occur. Factors such as Gross Domestic Product (GDP), population growth, climate change, structural change in economy policies and energy efficiency measures are long-term influence factors. Weather variables such as temperature, global irradiance, humidity, wind speed and rainfall affect electricity demand in short term with different relationship. In this context, it is extremely important to understand that a wide range of variables have a multi-dimensional impact on electricity demand

that sector analysts cannot overlook but on the contrary, assumptions and limits have to be defined. The expression multi-dimensional impact is intended to express that factors like weather conditions affect demand as a function of time, player, geographic place, and network level.

The daily electricity demand profile is strongly dependent on weather conditions, national days, special events, holiday period and day of the week. The analysis performed in this section shows how statistically the electricity demand profile trend can be considered almost constant during a month, making significant the subsequent analysis based on the monthly mean. In Fig. 1a, an example of a warm season week, in 2009 and 2015, of the electricity demand in New South Wales and in whole aggregated NEM regions is plotted. The comparison is between the week starting on Monday 26th of January 2009 and the week starting on Monday 26th of January 2015. In these two weeks, the weather conditions were comparable and so it is possible to eliminate, to a first approximation, the dependency of the demand by the meteorological conditions. The 26th of January is Australia Day, the annual National Day; on that day, the consumption is clearly minor than the rest of the week-days due to the closure of the majority of the businesses. The profile of NSW and NEM regions, during the week, is similar in shape and scale to the point that, even the rate between the daily maximum and the daily minimum assumes values comparable. While the daily minimum maintains values nearly constant throughout the week, the daily maximum is strongly dependent on the day of the week. In particular, a reduction of almost 10–15% occurs in the weekend compared to the maximum value of working-days. The difference can reach and exceed 1000 MW. Moving on the evolution of the demand in these last 7 years, a huge reduction in the total quantity requested occurs clearly both in NSW and NEM regions.
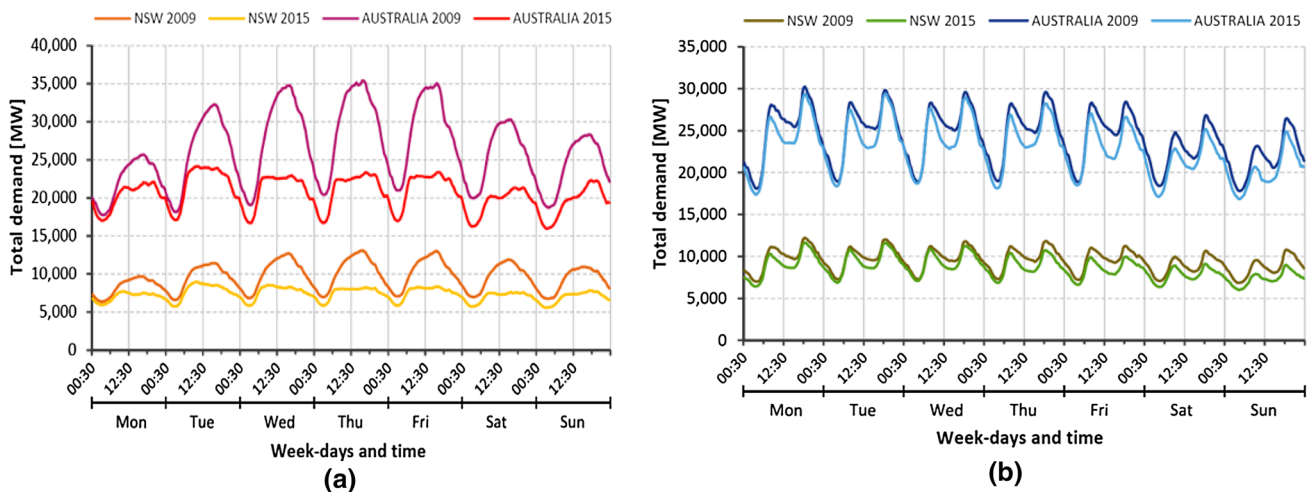
Fig. 1 Electricity demand profile in New South Wales and whole NEM regions **a** warm season and **b** cold season

The reduction is greater during daylight hours, making the profile more flat; during night hours, a reduction occurs as well and is largely due to energy efficiency [46].

Figure 1b shows cold season week, of 2009 and 2015. It is possible to observe of the electricity demand in New South Wales and aggregated NEM regions. The comparison is between the week starting on Monday 27th of July 2009 and the week starting on Monday 27th of July 2015. This week was chosen as that one of warm season to have weather conditions comparable and so it is possible, to a first approximation, to eliminate the dependency of the demand by the meteorological conditions. The profile of NSW and NEM regions, during the week, is similar in shape and scale. A reduction in the demand occurs clearly during the central hours of the day when the demand is reaching its minimum value during working hours. The reader should note that the depth of these minimums intensifies the difficulties of the network management. Given that the rate of change of the demand is increasing, flexibility and quick-time response of systems are necessary [47–49].

The characteristics of the demand in the cold season are similar to that in the warm season; as an example, the daily minimum maintains values nearly constant throughout the week, the daily maximum is strongly dependent on the day of the week, in particular a reduction of almost 20% occurs in the weekend compared to the week-days maximum.

The reason to base the following analysis on the monthly mean is the necessity and the will of eliminating the dependency of the demand on variability of weather conditions. Solar irradiance, temperature, humidity, wind, rainfall are the meteorological variables that most affect the demand and in good approximation can be considered constant in the same month during years. In Eq. (1), the correlation defines the hourly monthly mean.

$$\overline{P_m}(t) = \frac{\sum_{i=1}^{N_m} P_i(t)}{N_m}, \tag{1}$$

where $\overline{P_m}(t)$ represents the hourly monthly mean at time t; $P_i(t)$ refers to the electricity demand in the i-th day of the month at time t and N_m represents the total number of days in the month considered. In Fig. 2a, the profiles of the hourly monthly mean electricity demand of January and February in 2009 and 2015 are plotted. The dashed lines represent demand in 2009, solid lines in 2015. The two profiles in January and February are very similar both in values and in shape. Only one minimum is present that occurs during night and the maximum is reached in the afternoon.

While the reduction between 2009 and 2015 during the night varies in the range 600 MW–800 MW, values of 1700 MW during daylight hours are reached. The greatest reduction takes place in the interval between noon and early afternoon, in combination with the peak of the global irradiance. In Fig. 2b, the solid lines refer to the left vertical axis and show the value of the electricity demand reduction; the area chart represents the hourly monthly mean global irradiance in January and February and refers to the right vertical axis.

The profile of the demand's reduction is very stable during dark hours, in particular the percentage of reduction in 2015 compared to 2009 is about 10.7% in the interval between 20:30 and 7:00. Things change during daylight hours when the reduction curve has the same trend of the global irradiance, the maximum of the first one happens in conjunction with the peak of the radiation; in these hours, the reduction in demand grows to a maximum of 15.8%. While the values recorded during night are mainly all related to energy efficiency [46], those recorded during daylight
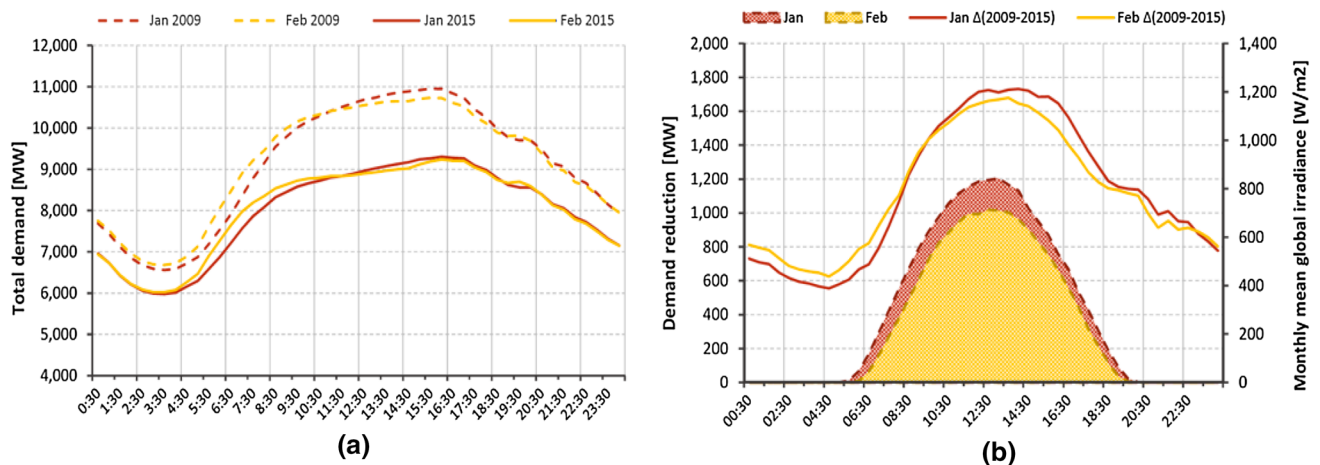

Fig. 2 Warm season **a** Hourly monthly mean electricity demand and **b** Hourly monthly mean reduction between 2009 and 2015 of the electricity demand and Hourly monthly mean global irradiance

hours are mostly a combination of energy efficiency and renewable energy. In detail, in 2015 in NSW, the total cumulative capacity installed of PV systems was 906.9 MWp in January and 925.0 MWp in February, while in 2009 was only 9.6 MWp. The contribution in the demand reduction is becoming, therefore, more and more significant. A model to evaluate the energy produced by aggregated PV systems and its results which show the past, the actual and the future impact of PV generation, on centralised resources and electricity demand, is presented, respectively. A comparison across the evolution of the monthly mean hourly demand profile in the last 7 years (2009 is the year when PV systems started their increasing penetration) gives the capacity to verify the impact of PV in the total demand. A first result is that there is a huge reduction in the warm season profile during the day according to the high solar exposure, while the same reduction is weakened in the cold season. Another import result is that in the night hours, there is a reduction as well.

The profiles of the hourly monthly mean electricity demand of January and February in 2009 and 2015 are plotted in Fig. 3a. The dashed lines represent demand in 2009; solid lines in 2015. The two profiles in July and August present two minimums that occur during night and afternoon; the maximums are reached in the morning and evening. As it is for the warm season, but to a lesser extent, there is a higher reduction, between 2009 and 2015, during the daylight hours than during dark hours. The reduction varies in the range 300 MW and 600 MW in the night and values of 1200 MW during daylight hours are reached in August. The greatest reduction takes place in the central hours of the day, in line with the peak of the global irradiance. In Fig. 3b, the solid lines refer to the left vertical axis and show the value of the electricity demand reduction; the area chart

represents the hourly monthly mean global irradiance in July and August and refers to the right vertical axis. The chart of the demand's reduction presents characteristic similar to that of the warm season; is very stable during dark hours, in particular the percentage of reduction in 2015 compared to 2009 is about 10.7% in the interval between 17:30 and 8:30. Things change during daylight hours when the reduction curve has the same trend of the global irradiance, the maximum of the first one happens in conjunction with the peak of the radiation; in these hours, the reduction in demand grows to a maximum of 15.8%.

Transmission infrastructure, transformers, power plants size and control network systems are all dimensioned based on the maximum demand, even if it has a frequency of only few times in a year for short period. It is extremely important for utilities to predict when the peak occurs, to better set the dispatching plans of rapid ramped up plants and to avoid the risk of outages and load shedding practice. Peak demand variations can have a daily, monthly, seasonal and yearly cyclicality. The hourly frequency of the daily peak of the electricity demand is reported in Fig. 4. The analysis is carried out on a trimester base, in the period that starts in 2009 and finishes in 2016. The red bubbles represent the two warm season trimesters (Jan–Feb–Mar, Oct–Nov–Dec), the blue bubbles the two cold season trimesters (Apr–May–Jun, Jul–Aug–Sep). The area of the bubble is the peak's frequency at a specific time during the trimester considered.

Analysing the cold season peak, in Fig. 4 it is possible to observe the presence every single year of a big blue bubble, in particular in the second semester at 18:00. This denotes a stability and a periodicity of the peaks. In the third semester, there are two smaller bubbles, with almost the same size at 18:00 and 19:00. In both the periods, the peaks are when the sun is already set and there is a combination of residential
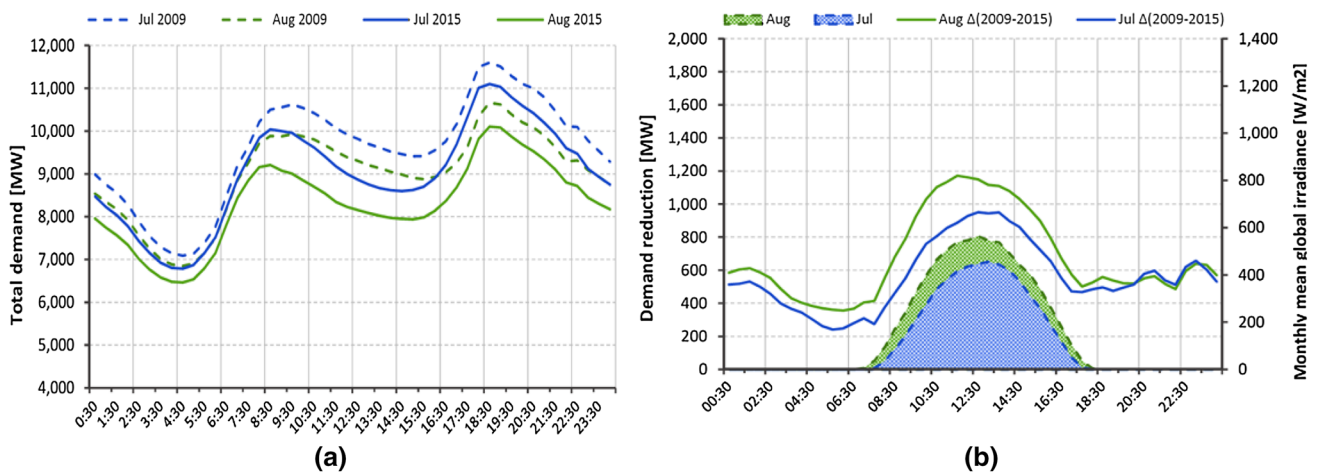
Fig. 3 Cold season **a** Hourly monthly mean electricity demand and **b** Hourly monthly mean reduction between 2009 and 2015 of the electricity demand and Hourly monthly mean global irradiance

Fig. 4 Hourly frequency of the daily peak in the period 2009–2015 on a trimester base
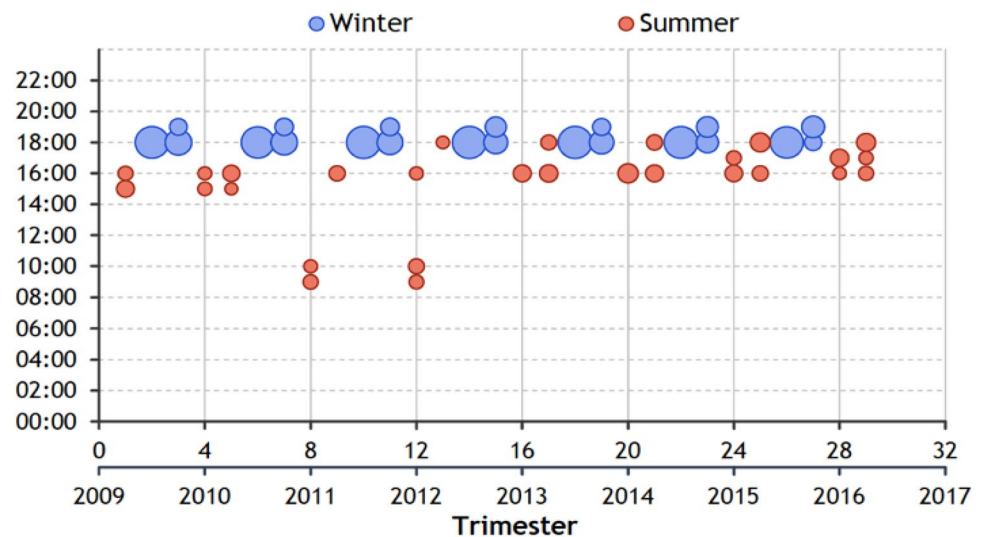
and commercial load for heating and lightening. As the peaks do not occur during daylight hours, PV energy does not affect peak demand neither on the quantity nor on the time. During the warm season, the situation is different, the maximum is moving indeed from 15:00 to 17:00–18:00. As the peaks in summer occurred during daylight hours when the solar irradiance is still very strong, photovoltaic systems can modify the profile, causing a flattening of the demand, and can affect peak in terms of quantity (peak shaving) and in terms of time (peak shifting). An increasing uptake of distributed PV systems is expected to bring peaks in the late afternoon when solar contribution can be considered negligible. In some occasions such as the last semester in 2010 and in 2011, the peak occurs in the early hours of the morning; this demonstrates again the effect of solar contribution, in fact the peak is pushed towards the hours in which the solar generation is low.

In [45], the Australia Institute investigated all the factors that are affecting the demand and reducing the consumption. The main factors considered are: Rooftop PV systems, Major industries closures, Efficiency programs, Income, Electricity price and Lower growth of large users. All these factors have a different impact on the consumption reduction. The PV systems represent the factor with the more unpredictable impact and with the highest potential to become in the next decades the main factor, which can drastically reduce the energy requested to the centralised generation.

Mathematical PV and BESS models

Mathematical PV models

In June 2016, Australia counted more than 1.57 million of individual rooftop PV systems with a total combined capacity of 5400 MW. The installed capacity represents almost 23.4% of the peak demand that occurs in summer (23,000 MW). The impact and the challenges, that the energy sector is now facing, are negligible compared to the future challenges that have to be faced as the uptake of this technology is expected to be unstoppable for the next decades, before the saturation point is reached. Some reports show future uptake scenarios where total PV systems capacity across NEM regions will be between 15,000 and 25,000 MW in 20 years, which means between three and five times the current levels. The energy generated by PV systems is not dispatchable; usually, the maximum generation does not occur at the same time of the demand peak and PV contribution ends when the demand starts growing towards the evening peak. In addition to these supply management challenges, there are several electric and power quality issues to face such as the voltage fluctuations, frequency variations and control systems that have to work in their design conditions in order to guarantee network reliability. Since real-time metering is not available for all the systems, the use of accurate and flexible models is becoming more and more important for utility and operators to estimate PV contribution and to produce forecasts. The methodology flow diagram and the different components of the PV model are represented in Fig. 5. In the scheme, the different colours represent, respectively: Orange: data or properties input; Light blue: model, data processing; Red: output model, post processing; Green: final output, main variable that influences PV generation.

The model is developed in Matlab environment. The variables that influence the PV generation depend on different parameters; in this model, these variables are calculated distinguishing between the following divisions: k: postcode; x: system azimuth angle (orientation); y: system slope (inclination); t: time and j: system size. The flexibility of the model

Fig. 5 PV generation model flow diagram

consists in the capability to simulate the behaviour of one system or of a group of aggregated systems. The size of the group simulated can be an area of a feeder, a single 2-digit postcode, a state or an aggregation of these different options.

Data concerning the list of all postcodes and the relative coordinates (latitude and longitude) are available in CSV format from the ABS (Australian Bureau of Statistics) and on the Australian Post' website (auspost.com.au). The list contains almost 16,700 different locations along all Australia. From this list, the coordinates of the areas of interest have been extracted. The term 2-digit refers to all the postcodes that start with the same two numbers (i.e., 2500, 2502, 2505,… 2594 are all parts of the 2-digit postcode 25xx). The coordinates of each 2-digit postcode are calculated as the mean of the coordinates of all the postcodes which compose the 2-digit postcode considered. A 2-digit postcode grid has been chosen to evaluate the PV contribute on centralised generation across all NEM regions. The simulation for all the 2-digit postcodes has been processed and each output has been summed to the contribute of the others, since details of

the capacity installed and the division of these systems into different size range are available from CER's and APVI's websites with an accurate level of detail only about 2-digit postcodes. The decision of the grid scale is driven by the available detail level of some parameters, which influence significantly the performance of the PV system.

When the simulation starts, the model requires some necessary inputs based on the extent of aggregation. It is also possible to add some more details relatively the design and the characteristic of the panel and the inverter; if these parameters are not inserted, the model uses default average value taken from the literature and the actual state of art of the technology.

The following inputs are for the simulation used of the PV contribution for all NSW:

- *One-system model*: Location coordinate as latitude (φ) and longitude (λ), system capacity (P_{INS}), inclination (β), orientation (γ), age of the system are the necessary inputs.

- *One-postcode model*: Location coordinate as latitude (φ) and longitude (λ), current capacity divided per system size (P_{INS}), inclination distribution (β), orientation distribution (γ), past cumulative capacity installed to consider system ageing are the necessary inputs.
- *Additional input*: Temperature coefficients of the module (β_{ref}), absorbance (α_g) and transmittance (τ_g) of the glass, dimension of the panel ($L \times W \times H$), thermal conductivity (k), density (ρ), specific heat capacity (c) and thickness (s) of the frame and of each PV layer, the type of installation (with mounting rack or installation directly on rooftop).

The solar-related models such as the isotropic or anisotropic sky models, solar position model and beam and diffuse components of daily radiation models can be found in [1, 4–6, 8]. For the ambient temperature model, a model presented at the European Solar Radiation Atlas (ESRA) was used for simulating the daily temperature cycle [10]. This model evaluates the dependency of the temperature on the time of the day (based on the local solar time) starting from only three inputs: the time of sunrise of the specific day considered, the minimum and the maximum daily temperature registered. The overall efficiency of a PV system model was found in [2, 3, 7, 9] and the heat transfer models in [50, 51]. Figure 6 shows an example of input data for the PV generation model.

Mathematical BEES model

Storage systems, since the advent of the distributed generation of electricity, have been considered the missing link necessary to solve the problems that the non-programmability of the energy production by renewable sources is introducing in the management of the network infrastructure. In addition, storage technologies were often considered the suitable solution for the critical management of the network in terms of demand–supply unbalancing, which involves nodes significantly congested both in the transmission networks and in distribution lines. The technological

ϕ latitude	-134.5	λ_loc longitude	-48.7	β slope	30	v surface_azimuth	15
year_start	2009	month_start	1	day_start	1	time_step	30min
year_finish	2035	month_finish	12	day_finish	31	P_ins	5 kW
eta_t_ref	0.14	beta_ref	0.005	albedo_ground	0.25		
tau_glass	0.91	alfa_glass	0.09	epsilon_glass	0.91		

	THERMAL CONDUTTIVITY (W/mK)		DENSITY (kg/m3)		SPECIFIC HEAT CAPACITY (J/kg)		THICKNESS (m)	
GLASS	ks_1	1.8	rho_1	3000	c_1	500	s_1	3.00E-03
ARC	ks_2	32	rho_2	2400	c_2	691	s_2	1.00E-07
PV CELLS	ks_3	148	rho_3	2330	c_3	677	s_3	2.25E-04
EVA	ks_4	0.35	rho_4	960	c_4	2090	s_4	5.00E-04
REAR CONTACT	ks_5	237	rho_5	2700	c_5	900	s_5	1.00E-05
TEDLAR	ks_6	0.2	rho_6	1200	c_6	1250	s_6	1.00E-04

Fig. 6 PV generation model input

development and the early diffusion of electrochemical storage systems are driving more and more interest of the international scientific research community to the observation and the analysis of the potentiality of these technologies in two different main strands. The first one is the use of storage systems with a local use logic as support for distributed generation, both in the residential sector (small scale systems) and coupled with real systems dedicated in producing energy from renewable sources (big scale systems). The second field of application is for the provision of network services and in particular, great attention is addressed to the potential participation of storage systems in the dispatching services market. The use in support of the distributed generation still presents several problems, mainly linked to the need for an appreciable reduction in the price of storage systems to make them a cost-effective investment for the domestic market or renewable plants. Despite the technological progress and the expected evolution of the market, the operators have to deserve particular attention for these aspect very dynamics. It is especially in the second type of use that the storage solutions appear even today to be competitive in the market. The future advent of the so-called storage farm, namely of real"plants" for the provision of network services through the storage, however, is not yet possible, where the regulatory framework does not admit the possibility of operating in the energy services market. The difficulties to predict the future uptake in a immature market which is at its first stage and the need to evaluate the possible impact the storage batteries will have on the network, are leading the scientific community to study and develop new approaches which will enable the network operators to be ready when the penetration of these technologies will reach significant values. The approach used is based primarily on the available characteristics of the distribution of PV systems in geographical and size terms. The impact of these technologies is assessed first by the uptake of BESS coupled with PV systems and subsequently even with the advent and the introduction of Electric Vehicles. As for the PV model presented, the BESS model consists in different components, as in Fig. 7 and calculates the contribution of the distributed batteries and the impact that the aggregation of all the future BESSs installations will have on the network.
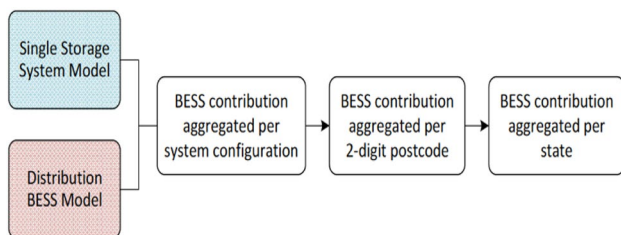
The first component is the *Single storage system model* which determines the energy flows in/out of the battery (charge/discharge) and in/out of the network (draw/inject) for each PV-BESS configuration considered. The second component is the *Distributed BESS model* which scales the results from the Single storage system model to the overall capacity installed with a geographical distribution (postcode) and a system size distribution (PV size category). The results then are aggregated to evaluate the overall impact of PV + BESS. The first component is divided into four sections:

1. The model of the operational logic of a single storage which determines the behaviour of the storage based on the State Of Charge (SOC), the PV generation and the electricity demand. The electricity tariff is another factor that can influence the storage behaviour, but since in NSW currently the most adopted tariff by customers is a flat tariff; it has been decided to not consider the electricity price. In a future scenario in which a Time-Of-Use (TOU) tariff is adopted by more customers, it will be necessary to consider the price as a determining factor of the battery behaviour as a case in which the charge of the storage can be more convenient drawing current from the grid; this case can also occur during the discharge stage.
2. The second component determines the optimal size of the battery for the PV system configuration considered. The calculation is the result of an optimisation process based on the customer type (residential, commercial), the relative electricity demand profile, the seasonal total consumption and the average seasonal peak.
3. The electricity demand profile of the type of customer considered, which is the result of the previous optimisation process.
4. The cumulative performance degradation model which considers the cumulative capacity fade (%) of the BESS cycle by cycle based on the battery operating temperature, the current rate (C-rate), the State Of Charge (SOC) and the Depth Of Discharge (DOD), which are the themselves the results of the previous iteration of the model.

The PV generation profile (the result of the PV model) for the specific PV configuration (system size, slope, azimuth, and location) is generated and becomes one of the inputs of the first component (Single storage system model). The second component is divided into two sections:

1. A geographical division, in which the total capacity installed is divided into the different postcodes based on the PV capacity installed.

Fig. 7 BESS model scheme

2. A system size division, in which the capacity in each postcode is split into the different PV system size categories using the actual ratio.

The results of the 30-min simulation are then aggregated to have the overall PV + BESS contribution which are added to the demand forecast. A wide range of different Energy Storage (ES) technologies are now available in the market. Not all are suitable for the integration with unpredictable renewable source as PV systems in the residential sector. In a CSIRO report [52], five electrochemical batteries are identified as the most likely to be adopted in the early future. The actual Li-ion batteries' average cost per kWh is considerably lower compared to the others technologies; in some cases, it can be less than half of the costs for a zinc bromide flow battery or an advanced lead acid battery. Several factors influence the actual costs of these technologies. Considering Li-ion batteries, on the one hand they are now benefiting from the high maturity of the technology as they have been used for many years in consumers electronics such as computer laptop, smartphone, and on the other hand, the extraction cost of the Lithium is at the minimum level as the large volumes of the demand requested. It is important to underline that this technology has also a wider range of full charged–full discharged level, the DoD is 90% indeed and compared to other technologies does not suffer excessively of a complete discharge. Considering the high value of cycle life (4000) and of lifetime years (10), this technology is particularly suitable in application where a cycle of charge and discharge occurs every single day (10 year × 365 day/year × 1 cycle/day = 3650 ≈ cycle life). Applications with the previous characteristics can be found in the applications coupled with PV systems both in residential and commercial sector and in the automotive industry. The maturity and the advanced performances of the Li-ion batteries are driving all the energy sectors to invest in this technology for the early future.

## Simulation results and discussion

PV simulation results and correlation development

The simulation data of the PV generation model are correlated with the APVI's website measured data in the period April 2015–August 2016. The data from this institute are available only for this period and represent the monthly total output from PV systems in NSW. These data are measured from a group of few thousands PV systems scattered around the country; then the data are scaled to the totality of the capacity installed in Australia assuming that the data from these systems are representative of the total 1.6 million of systems installed. Once the data are collected, they are transformed in the monthly mean daily output and then are compared to the data generated by the PV model. In Fig. 8, the column chart represents the monthly data from the PV generation model with the green columns and the data from APVI's website with the light blue columns, and they refer to the left axis.

The solid line refers to the right axis and represents the percentage difference between the simulation data and the measured data. It is evident that higher differences between the two set of data occur during the cold season compared to the warm season. In this latter in fact, differences lower than 10% are registered. Since the PV model does not include any shading factor, as several information are necessary to model this aspect even for one system, it is evident that the difference is emphasised during the cold period when the solar altitude is lower. It is not possible to model the angular position, the distance and the height of buildings, overhangs, trees and so on for each system. A statistical approach to this problem can be the solution but it is important to have clear data to validate the approach. Figure 9a shows the total solar exposure reaching a tilted surface during the year. The X axis represents the surface azimuth and the Y axis the surface slope. This chart depends only on the solar irradiance and the orientation of the surface, thus representing only the

**Fig. 8** Correlation between simulation data and measured data
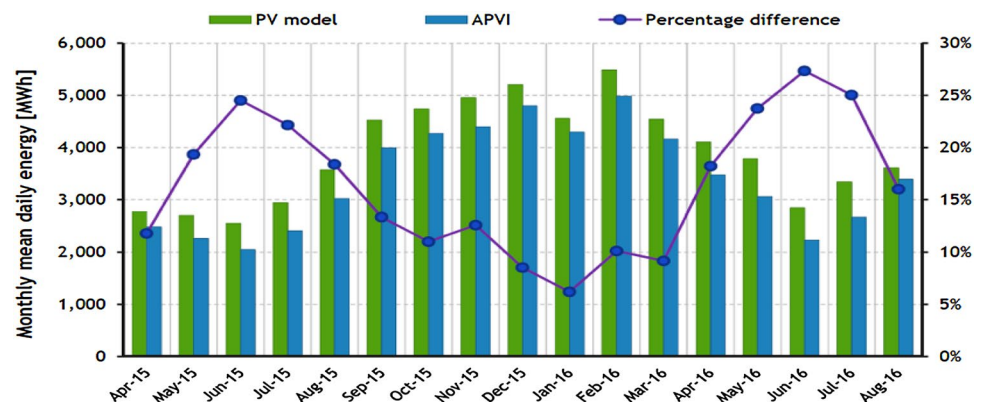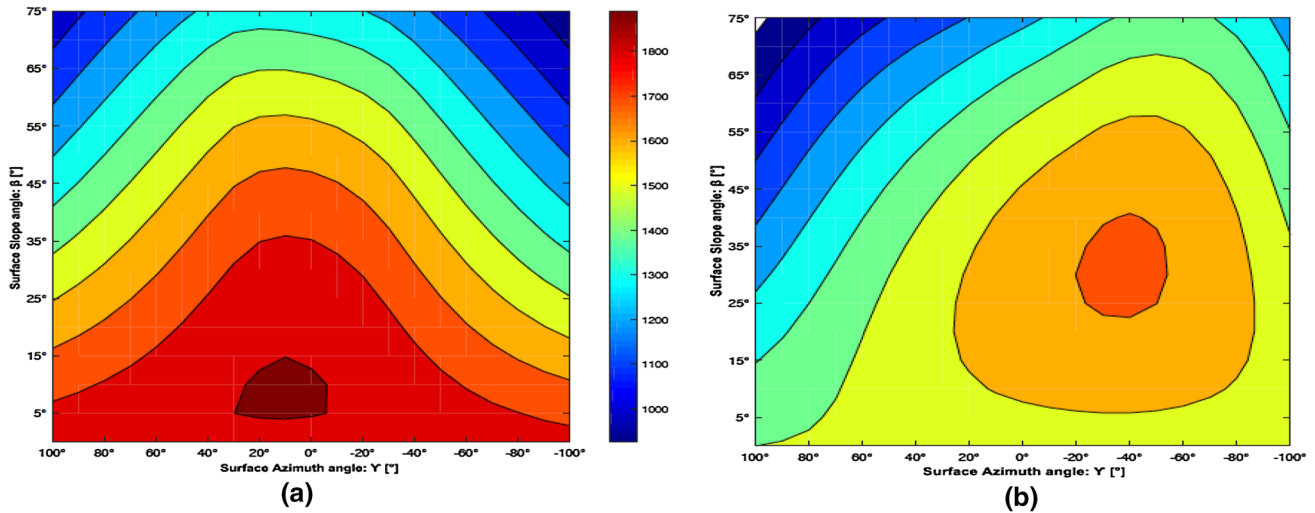
Fig. 9 Total annual solar exposure **a** tilted surface and **b** energy effectively produced

possible convertible energy. The total energy converted during the year (thus the effective energy produced by the PV system) is shown using the same axes in Fig. 9b. The contribution of the thermal model is evident as the optimal configuration is a system oriented towards north-east, precisely between $-40° < \gamma < -30°$ and with an inclination between $25° < \beta < 35°$ which optimises the performances during the year. The configuration that receives more energy (just considering the solar irradiance) has an orientation between $0° < \gamma < 20°$ and an inclination between $5° < \beta < 15°$. A first consideration is that the configuration which optimises the energy on the titled surface ($\approx 1,950$ kWh/year), effectively can produce almost 350 kWh/year less, thus approximately 1600 kWh/year. Two main factors are the causes for this result. First, the orientation of this configuration guarantees to receive more energy after solar noon (12 p.m.) when

the air temperature is reaching the daily maximum and as a consequence the operating panel temperature is close to its maximum. Thus, the thermal performance of the panel, especially in summer, is not optimised with this orientation. Secondly, the slope of about 10° maximises the energy reached in summer as the solar altitude assumes values between $65° < \alpha_s < 80°$, but on the other hand does not allow an efficient heat transfer. In particular, the forced convection mechanism is not significant as the surface to the horizontal wind is not relevant.

In Fig. 10, the hourly frequency of the daily peak of the electricity demand is plotted for the period 2015–2035, in the future scenario with a high penetration of PV systems. The analysis is carried on a trimester base. The area of the bubble is the peak's frequency at a specific time during the semester considered. The daily peak during the cold season

Fig. 10 Future hourly frequency of the daily peak in the period 2015–2035 on a trimester base in the future high penetration scenario of PV systems
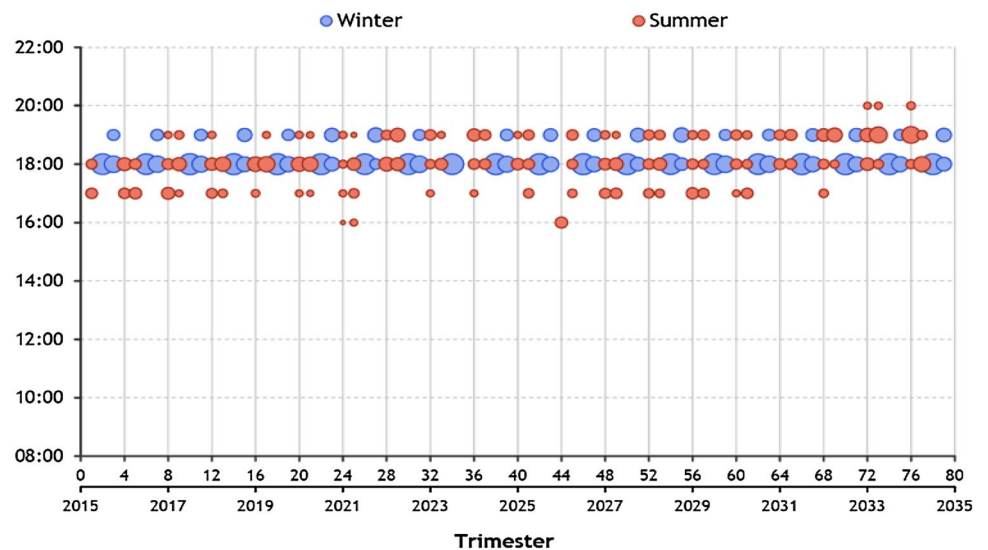
does not change its characteristics and continues to occur in the late afternoon when the sun is already set. Thus, the PV contribution does not affect the peak. During the warm season, the peak, that now occurs during the daylight hours (around 17:30–18:00), is moving towards the early evening. The PV generation is the main actor in this scenario, since its contribution is still very high at the time in which the peak occurs now.

Prediction of the future derivative electricity demand

The derivative of the actual electricity demand was analysed, showing the necessity from AEMO to adopt different behaviours in network operation plans during warm and cold seasons [53–57]. This necessity is driven by the different use of electricity during the daylight hours for heating and cooling devices. The network operator has to manage it using a long-term strategy concerning the use of peak power plants with short turn-on time. In this section, the derivative of the electricity demand in 2025 and 2035 under high future uptake is compared to the year 2015. This comparison is useful to evaluate how the continuous growing penetration of PV systems will affect the strategy and the dispatching plans of centralised generation taken to guarantee the demand–supply balancing into the network. In addition to this evaluation, the analysis gives a starting point of view about the possible role and about the operation logic, which domestic storage technologies can have to support the network. As electricity demand, strongly affected during daylight hours by PV generation, will change significantly in future, it is expected that the derivative of the demand will change as well. During the warm season, in January and February 2025, the demand presents two peaks during the day, unlike 2015 in which only one peak occurs. The first peak is around 8:30 and the other one is at 18:00. All this is confirmed looking at the derivative in 2025 in Fig. 11a (solid line), where it

assumes value equal to zero when the demand reaches the two peaks. Compared to 2015 (dashed line), the derivative in 2025 during the early morning presents values always lower, resulting in a lower average slope of the demand. For the first time, the derivative assumes negative values during the daylight hours, in accordance with the decrease in demand after the peak at 8:30. A minimum is also presents around 11:30 when the derivative is equal to zero and the solar irradiance is reaching its peak.

The contribution of PV generation during summer months affects the derivative starting from 5:30. In the morning hours, the demand grows less and less quickly as it is possible to observe in the positive part of the bar charts, which represent the slope reduction between the demand in 2015 and 2025. Thus, a positive contribute is given during the morning; while from the minimum at 11:30, the demand grows more quickly and the derivative assumes value higher in 2025 than in 2015 for all the hours till sunset. The bar charts are negative in this interval, showing how the PV generation is going to cause a more difficult management of the centralised resources when the PV contribution starts to decline. The increase in the ratio of the demand over time can reach 500 MW/h around 16:30 when the peak previously in 2015 occurred. The new evening peak in 2025 will occur at 18:00, when the derivative is equal to zero. The situation in 2035, as in Fig. 11b, is amplified compared to 2025, both in the morning and in the afternoon. In 2035 during the morning, the continuous increase of energy injected into the network by PV systems is going to reverse the benefits till 2025 obtained. Indeed at 9:30, after the morning peak, the almost 2300 MW generated by PV systems start to create a steeper descent (negative bars) towards the minimum. In the afternoon, as in 2025, there is worsening of the ramp of the demand which in this case can reach 750 MW/h around 16:30 compared to 2015. The evening peak, as a result of the high PV energy produced even in the late hours of the
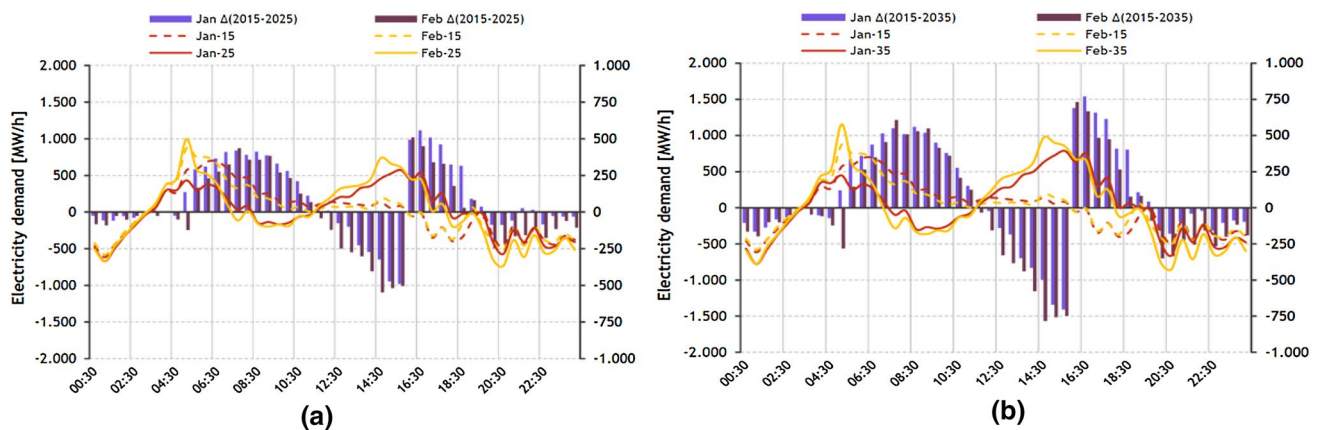

Fig. 11 Warm season: evolution of the derivative of the electricity demand in NSW under high uptake scenario in **a** 2025 and **b** 2035

afternoon, will move at 19:00. In conclusion, it is possible to observe that during morning hour,s the penetration of distributed PV systems will lead to a more flat demand profile till 2025 and in 2035 the massive energy generated will bring to an inverted situation. In the afternoon after the minimum, the ramp of the demand is already becoming steeper starting from 2025 and this trend will be emphasised in the subsequent years. It is evident that a more accurate analysis of the future derivative of the demand has to consider and model the effect of energy efficiency programs on the shape of the profile of the request. The assumption of a constant increase of the demand for all hours of the day is likely conservative. The increase of energy efficiency such as air conditioning systems will drastically reduce the demand during the central hours of the day, increasing thus in summer months the depth of the U-shape as the use of conditioners is mainly concentrated in the hot hour of the day. The impact of PV generation on the derivative of the demand during cold season can be summarised into two aspects. The first one is that the minimum occurring during the daylight hours is going to move from 14:30 to 12:30 as early as 2025 when the PV contribution has its maximum. In 2035, this consideration is confirmed as it is possible to observe by the derivative equal to zero both in Fig. 12.

Concerning the peaks, the morning maximum is going to occur an hour earlier than in 2015 (thus at 08:00 in July and 07:30 in August); the evening maximum instead, as it is when the sun is already set, remains at 18:30. The second consideration is that the PV contribution is not going to help any networks operation. Looking at the bar charts is clear that the energy generated is making the characteristic U-shape of cold season deeper and deeper with the result of ramp of the demand emphasised both when the demand start to decrease after morning peak and when the demand start to increase after the noon minimum. Value of 750 MW/h and 1000 MW/h are reached in the interval 8:30–10:30 in 2025 and in 2035 respectively, this means to turn-off in 2 h

2000 MW (equivalent of 3 big fire coal power plants). On the contrary between 15:30 and 18:00, to balance the fast growing of the demand which can reach peak value equal to 1750 MW/h and 2000 MW/h (average value during the interval of 1400 MW/h and 1700 MW/h), it is necessary to have available around 4000 MW of capacity ready to turn-on in short time. This aspect will have serious implications both on economic perspective and on environment, considering the high-energy losses and the excessive use of fossil fuels (higher running costs) since the power plants will not work in the designed conditions range.

Simulation results of the BESS contribution

The results from the BESS model and of the EV impact are presented only for the high future uptake scenario. The reasons for this choice are first the willingness to show the results with the same assumption used to present the result of the PV model; the second reason is that since BESSs can have a positive effect on the network, it is interesting to show the more optimistic scenario to know the maximum benefit available from their contribution with the current forecasts. Some considerations are included in the final results. In the first scenario (Sect. 5.1.2.1), the contribution of the PV and of the adoption of BESSs is presented for 2025 and 2035, both during warm season and cold season in order to analyse the different impact that the batteries can have in the months in which their contribution is highest and lowest as strictly dependent on the solar energy. In the second scenario (Sect. 5.1.2.1), the contribution coming from EVs charge is illustrated placing a special emphasis on the new night peak and on the consequent issues both in terms of the capacity installed of the centralised plants and in terms of network management.

Scenario 1: high penetration of PV + BESS The main results of the BESS model for the warm season of 2025, in particu-
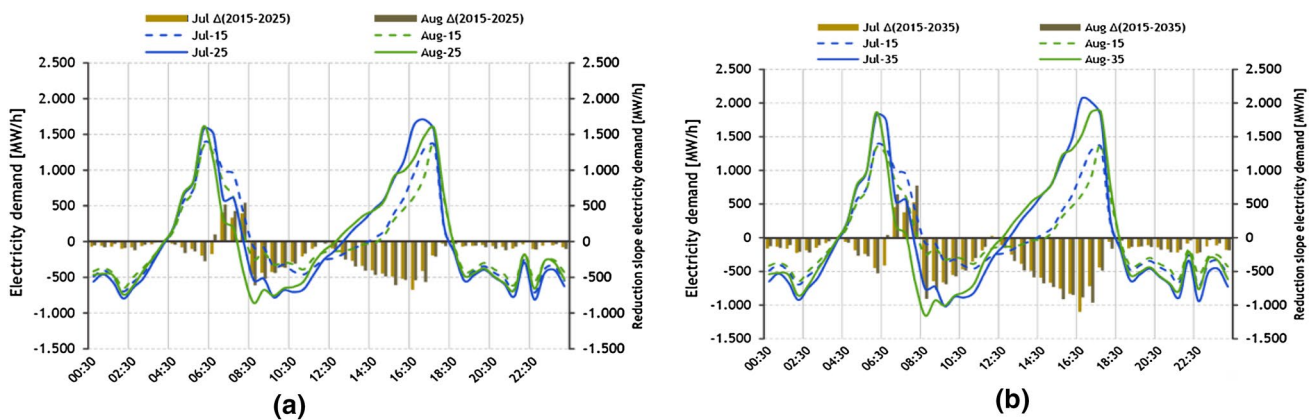
Fig. 12 Cold season: evolution of the derivative of the electricity demand in NSW under high uptake scenario in **a** 2025 and **b** 2035

lar January, are studied. In this season the BESSs' capacity accounted for the residential sector is only around 30% of the total capacity installed. The results showed that it is possible to observe that the contribution of the BESSs is concentrated mainly in two moments of the day (Fig. 13). In particular the charging phase goes from 6:30, when in some residential applications the PV generation exceeds the electricity demand, to 12:30 when almost all the batteries are fully recharged. The discharging phase starts at 16:30 and ends around 00:30. It was noticed that during the charge/discharge phases, the strong reduction is during the night

at 20:00. The energy drawn from the batteries is due to the complete discharge of BESSs of the commercial sector. The contribution coming from BESSs during the night is mainly due to the residential sector. Moreover, the derivative of the demand in NSW with and without the contribution of the BESSs shows the fact that the so small capacity of batteries installed is not affecting the overall demand. Thus, in conclusion, it is possible to state that the same considerations described for the impact of only PV are still valid in the warm season of 2025 with the adoption of BESSs. The simulation results for the cold season (Fig. 14) in 2025, in
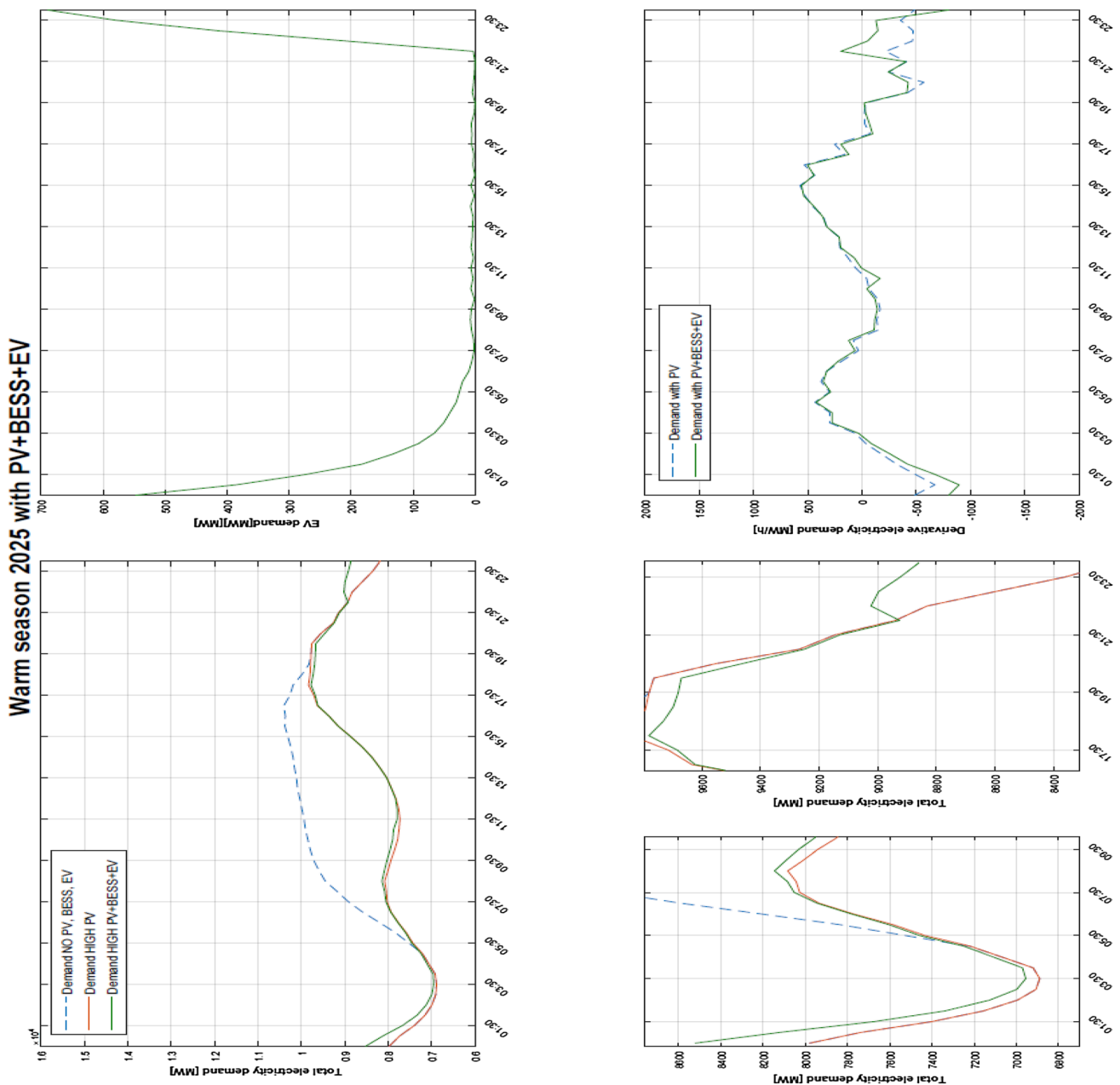

Fig. 13 Impact PV + BESS + EV during the warm season in 2025

particular July shows as the first main difference compared to the warm season of 2025 is that the charge phase lasts from 8:30 to 15:00, with just a little energy injected into the grid from the commercial sector around 14:00 when its batteries are almost fully recharged. This result is not because all the batteries are fully recharged but because the PV gen-
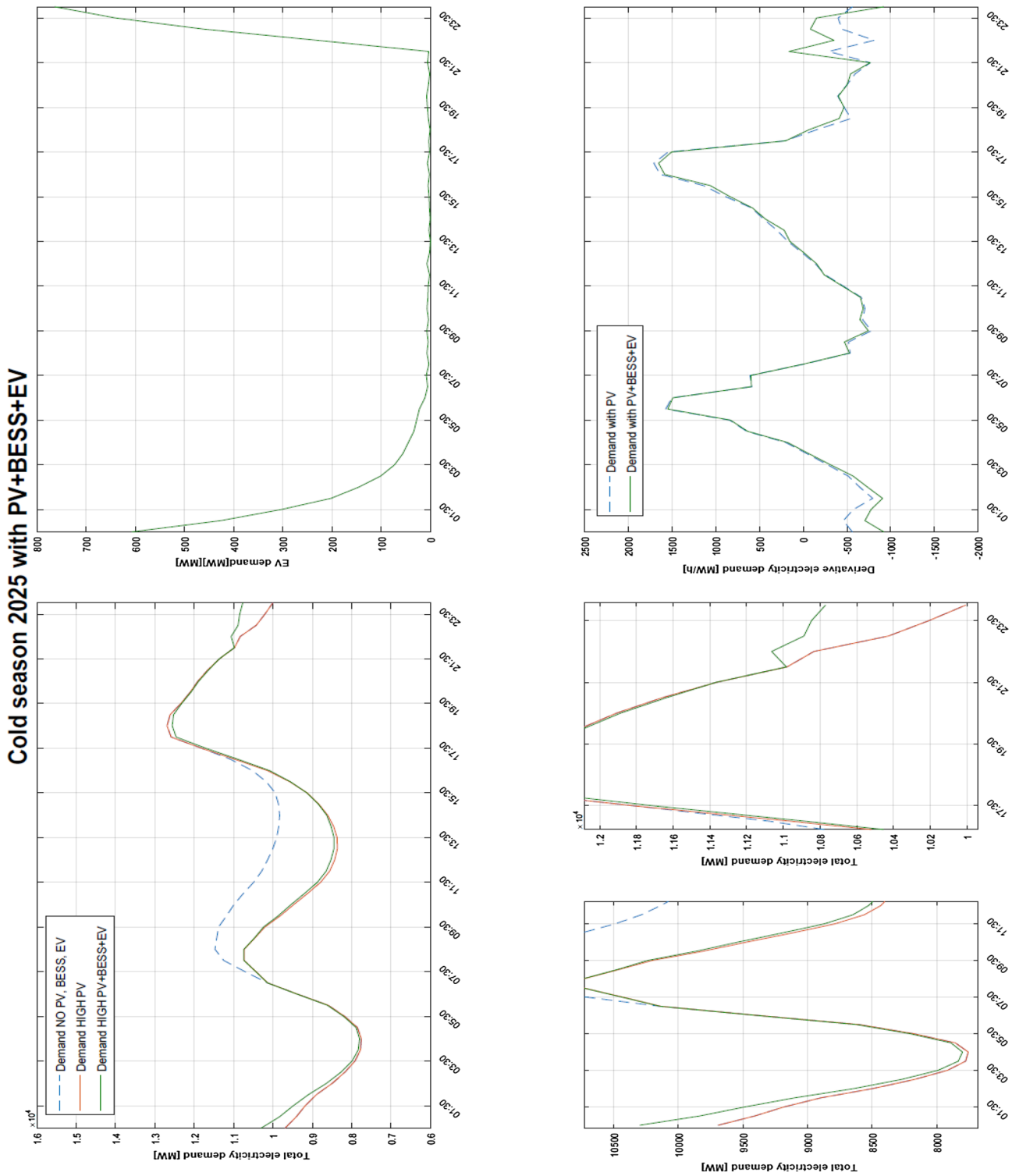

Fig. 14 Impact PV + BESS + EV during the cold season in 2025

eration starts to be lower than the demand after 15:00, thus at this time starts the discharging phase. In fact, the batteries of the residential sector hardly complete the recharge as the demand is higher than in summer and the PV generation is lower. For this reason, the discharge phase lasts only few hours: from 15:00 to 21:00. These considerations are clear looking at the fourth chart, in which the green line represents the aggregated demand of the residential and commercial customers, which adopt the BESS. In 2035, the share of the total capacity accounted in the residential sector reaches almost 60% of the total capacity, reversing completely the proportion compared to 2025. For this reason, the impact of BESSs on the demand is expected to be driven mainly from the residential BESSs' behaviour. As the capacity installed is much higher than in 2025, it is possible to observe a greater impact of the BESSs both at 12:00 in the morning and 20:00 in the evening during the charge and discharge, respectively. To confirm that the impact on the demand derives more from the residential sector, it is possible to observe that the maximum contribution during the charge phase occurs at 12:00, an hour later compared to warm season in 2025. In fact, at 12:00 the demand in the residential sector is around 5%–10% lower than at 11:00, thus allowing to store a higher quantity of energy; in addition, even the PV generation is higher at 12:00 than at 11:00. During the discharge stage, the reduction (in percentage) that occurs at 20:00 (as in 2025) is much lower due to the still high energy available in the batteries in the domestic applications. Another interesting consideration is that the charge stage lasts around 1 h more than in 2025 for two reasons; first, the higher presence

of residential systems which takes longer to fully recharge (less difference between PV generation and demand) and the second reason is that the performance of the PV systems installed in 2016–2025 is strongly decreased in 2035, while the batteries of these systems are almost new as they are changed every 10 years. In Table 1, the results of the impact are summarised. During the cold season, as the PV generation is much lower than in warm season, the higher presence of residential BESSs is less noticeable. Compared to cold season in 2025, the short period, in which the commercial sector fully recharges the batteries and a little energy is injected into the grid, completely disappears because of the drop-in performance of the PV systems almost at the end of their lifetime. Concerning the derivative of the demand in chart number five, it is possible to observe an average reduction of the maximum of around 150 MW/h, which is the effect of the high energy drawn from the batteries. The reduction is about 7% and the support of the batteries has a valuable contribution for just 1 h from 16:30 to 17:30 when the demand reaches the higher growth rate. An interesting result is that in some days, the support of the BESSs during the charge phase increases enough the demand to bring back again the daily minimum to occur during the night. The most critical situation, concerning the balancing of the network, occurs during cold season as the very rapid change in the demand in the afternoon. Thus, the adoption of BESSs may support the network operations, but as in these simulations the impact of BESSs during cold season is always lower than during warm season and not particularly efficient from the aggregated point of view of the centralised generation.

Table 1 Impact of BESSs on the electricity demand: warm and cold season, respectively, in 2025 and 2035

Maximum BESS contribution		Charge			Discharge		
	Capacity [MWh]	Power [MW]	Time [h]	Impact [%]	Power [MW	Time [h]	Impact [%]
2025 warm season							
High	708.8	269.32	11:00	2.7	− 178.74	19:00	1.8
Medium	605.8	219.60		2.2	− 155.39	20:00	1.6
Low	502.2	183.87		1.8	− 134.50	19:30	1.3
2025 cold season							
High	749.7	199.65	12.00	1.8	− 241.71	18.30	1.9
Medium	640.8	163.59	12.30	1.5	− 211.22		1.7
Low	531.9	134.99		1.3	− 176.83		1.4
2035 warm season							
High	1835	503.40	12 :00	4.4	− 401.57	20:00	3.5
Medium	1568.3	426.50		3.7	− 331.14	19:00	2.9
Low	1301.7	348.03		3.1	− 273.16		2.4
2035 cold season							
High	1893.4	349.43	12.30	2.7	− 445.67	18:00	3.1
Medium	1618.3	301.98	12:00	2.4	− 401.82		2.7
Low	1343.2	246.23	12:30	1.9	− 306.08	17:30	2.1

In Table 1, the results of the maximum BESSs contribution indifferent years and seasons are summarised.

Scenario 2: high penetration of PV + BESS + EV The simulation results of the BESS model with the addition of the EV load are studied for the warm season of 2025, in particular the month of January (Fig. 13). The charts are presented for the scenario with high uptake of EVs, in accordance with the assumptions used for the future adoption of the PV and storage technologies. The presence of almost 620,000 EVs raises the demand during the night by up to 690 MW. The contemporaneity of the beginning of the recharge of these vehicles is significant around 22:30 when statistically almost all the vehicles are on charge. As the load coming from the EVs' charge mostly takes place in the central hours of the night, the request of electricity for the recharge starts significantly to decline at the early hours of the morning. Thus, the demand decreases quicker than in the scenario without EVs. In fact, the derivative around 00:30–03:00 is steeper (in this case more negative) as it is possible to observe in the fifth chart represented in Fig. 13. In Table 2, the details of the maximum impact of the EVs charge on the demand (that is the demand with the high penetration of PV systems and BESSs) are summarised; in particular the number of EVs, the maximum additional demand requested by the EVs charge, the daily energy due to the recharge and the percentage that this energy represents on the total daily consumption. During the cold season of 2025, in particular in July 2025, 6 months later than the warm season of the previous section, the number of EVs on the road is increased

by around 67,000 of units. This means an extra load; almost 73 MW added to the maximum load at midnight and an additional 213 MWh to the daily energy. Figure 14 shows the cold season scenario in 2025 with the adoption of Electric Vehicles. As for the warm season in 2025, the still low uptake of EVs does not affect significantly the demand profile. The network operation in terms of dispatching plan for the centralised generation is not altered or at least not more than for the warm season. The EVs charge in fact for the scenario developed in [58] is not affected by the season (has the same profile), thus as the profile of the demand is very similar during the night in the warm and cold season, even the impact of the EVs on the demand is very similar. In the warm season of 2035, the uptake of EVs is expected to be more than three times compared to 2025. The almost 2.1 million EVs in the high uptake scenario will add up to 3400 MW to the demand during the night. The maximum demand peak will be moved to the night and will no longer be in the evening. This leads to an increase of the daily energy of more than 10 GWh. Both the increase in the demand peak and the increase of daily energy make it necessary to adopt new dispatching strategies and new approaches to these new challenges. The main problem is that this additional power is concentrated over a few hours and has to be provided very quickly. Looking at the derivative, in the fifth chart it is possible to observe a very step increase of the demand at 21:30 when the demand starts to growth with an average rate of 1,3500 MW/h till 23:30. Thus, in nearly 2 h, the centralised generation is requested to provide 2700 MW of additional power (around three big

Table 2 Impact of EVs on the electricity demand: warm and cold season, respectively, in 2025 and 2035

Maximum EV contribution			
	Number EVs [#]	Max Load [MW]	Daily Energy [MWh]	% Daily Energy [%]
2025 warm season				
High	619,706	689.30	1937.86	0.87
Medium	243,104	270.40	761.16	0.32
Low	90,399	100.55	282.01	0.13
2025 cold season				
High	686,539	763.64	2149.32	0.85
Medium	286,544	318.72	891.11	0.36
Low	101,826	113.26	317.13	0.12
2035 warm season				
High	2,106,596	3398.34	10,283.89	4.1
Medium	1,155,229	1863.60	5592.02	2.2
Low	541,033	872.79	2606.23	1.0
2035 cold season				
High	2,173,269	3505.90	10,480.17	3.5
Medium	1,206,713	1946.66	5881.49	2.1
Low	568,045	916.36	2749.56	0.95

coal fire plants). As the uptake of EVs is considerable in all the states of Australia (in proportion with their population), it is not possible to receive a significant support in the balancing operations using strategies of import/export of energy with the neighbours states. Once the demand reaches its peak at midnight, immediately decreases rapidly with a maximum rate of −2000 MW/h, thus making even harder the operations to follow the demand with the supply as it is requested to turn-on and turn-off around 3000 MW in 4 h compromising eventually the performances of the plants. In Table 2, the impact of EVs is summarised. The number of EVs does not change a lot between the warm and cold seasons of 2035. Thus, the impact on the electricity demand is very similar. The presence of three different peaks during the day will make necessary to drive the centralised generation towards future investments in more flexible plants with a short turn-on and turn-off time. The need to change the generation share capacity (from the point of view of the fuel source), the need to improve the transmission infrastructure to avoid congestion problems and the need to develop more interconnected communication systems will lead to a drastic change in the regulatory activities by AEMO, to new methods of remuneration by the utilities, to new business models and to new networks codes to maintain the security and reliability of the power system [24–28]. The EVs charge impact during the working hours is negligible as the report has modelled the EV charging phase to occur during the night as an adequate infrastructure for a future recharge in the work place is not yet planned. Some results of the maximum contribution of EVs are reported in Table 2 considering different years and seasons.

Prediction of the future electricity demand with PV, BESSs and EVs

In Fig. 15, the electricity demand profile in NSW under the high future uptake scenario of PV systems, BESSs and EVs during warm season is plotted for season 2024/2025 and 2034/2035. It is evident that the EVs charge during the night will strongly affect the profile of the demand, moving the peak from the late afternoon to the night in season 2035. During the daylight hours and out of the period in which the EVs are on charge, the demand is not changed compared to the scenario in which BESSs are not considered.

In Fig. 16, the electricity demand during the cold season is plotted for 2025 and 2035. The same considerations can be done of the warm season. In fact, the BESSs do not affect the demand profile significantly. The EVs will cause an important modification of the demand profile during the night.

In Fig. 17, the ratio of the cumulative BESS capacity installed [MWh] to the monthly mean daily PV generation [MWh] is plotted with the blue solid line, which refers to the left axis. This ratio represents the fraction of the overall energy generated by PV systems that can be stored in the BESSs.

The profile of this chart fluctuates with a yearly cyclicality. As the daily generation in January is the highest, the fraction that can be stored is the lowest of the year. In fact in 2035, the possible storable energy during the day is only around 9%; thus, it is evident that the BESSs contribution in supporting the network and mitigate the PV impact is not relevant. In July, the situation is different and the possible storable fraction of the PV generation is around 16%, since the daily generation is significantly lower than in January. Therefore, the BESSs do not have a significant role in the peak-shifting and peak-shaving practices, while the
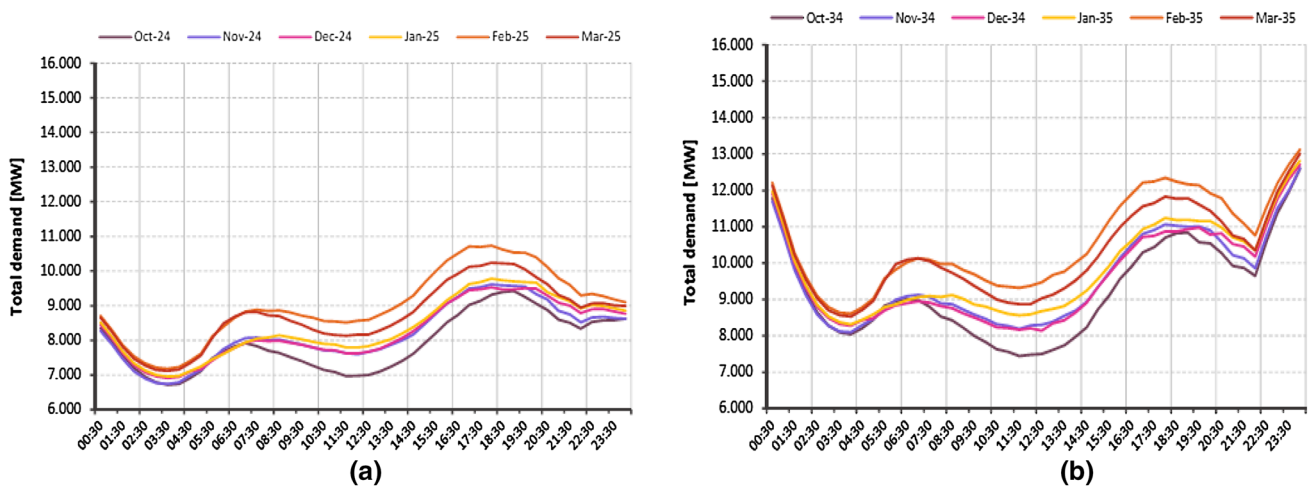

Fig. 15 Warm season: Hourly monthly mean electricity profile in New South Wales with the PV, BESSs and EVs contribution from October to March in **a** 2025 and **b** 2035
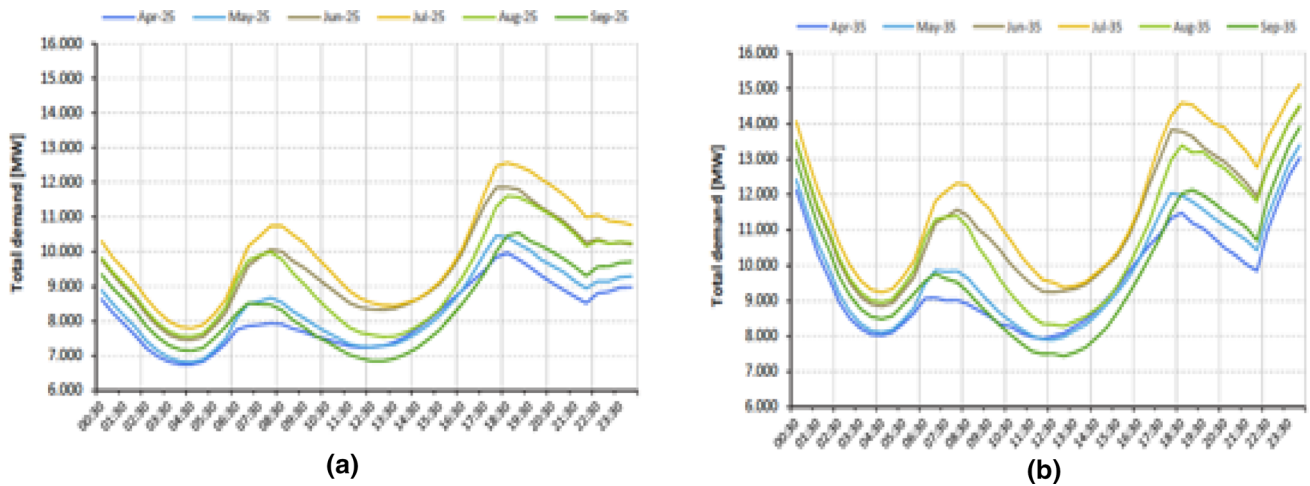
Fig. 16 Cold season: Hourly monthly mean electricity profile in New South Wales with the PV, BESSs and EVs contribution from April to September in **a** 2025 and **b** 2035

Fig. 17 Ratio of the BESSs capacity to the daily PV generation and ratio of the BESSs capacity and PV capacity installed
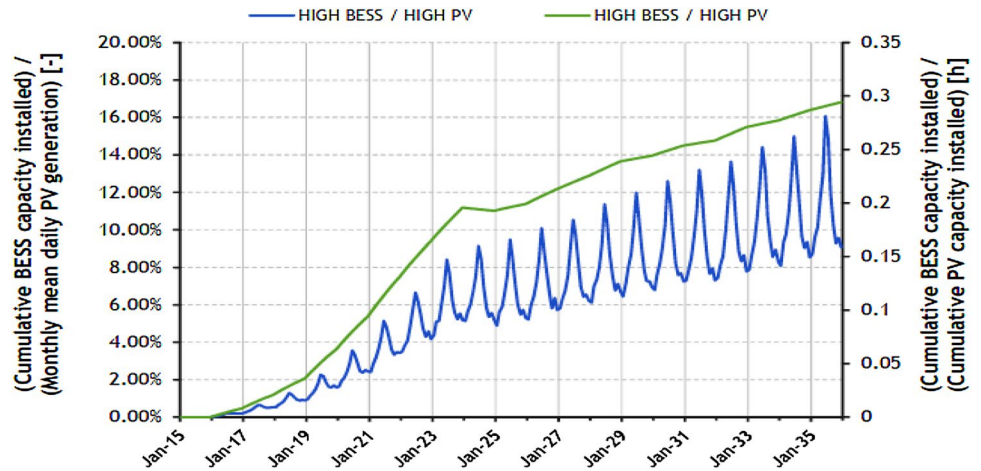
storable fraction remains low. The green solid line, which refers to the right axis, represents the ratio of the cumulative BESSs capacity installed [MWh] to the cumulative PV capacity installed [MW]. This ratio is the hypothetical time, expressed in [h], necessary to fully recharge all the BESSs if the PV is generating in nominal conditions. It is evident that if this fraction assumes low values, then the BESSs can contribute to the support of the network and mitigate effects of the PV contribution only for limited periods.

Conclusions

The rapid deployment of distributed PV systems, mainly in residential applications, is starting to represent a considerable portion of the available electrical power generation and, for this reason, the stochastic and intermittent nature of these systems is affecting the operation of centralised resources.

Network operators are facing more and more difficulties in forecasting activities due to the complexity of the scenario. In this context, the future adoption of BESSs is considered as the possible solution to mitigate the problems that the advent of RES has introduced. The first results are achieved in the analysis over 7 years, starting from 2009 of the electricity demand evolution in NSW. The analysis showed that an evident reduction of the consumptions both during the warm and cold season is occurring during whole day. This reduction, though, is particularly greater during the central hours of the day and its profile assumes the same trend of the solar irradiance. The decrease in consumption during the day results in a steeper ramp of the demand in the afternoon when the demand starts to growth towards the evening peak, especially in the cold season.

Therefore, in this work, a model to evaluate the aggregated generation of rooftop PV systems along with a model to simulate BESSs and EVs future contributions has been

developed in MATLAB, to assess the current and future impact of these technologies on the centralised paradigm. The simulation of the future aggregated impact of PV systems in New South Wales (NSW) under the scenario of high penetration (3.7 GW in 2025 and 6.5 GW in 2035), showed a clear alteration of the profile of the demand during the warm season that has always been characterised by a demand almost constant during the day and a slight peak in the late afternoon. The demand in this season will be more similar to that one in the cold season therefore, with two peaks and with the characteristic U-shape during daylight hours. The peak will occur later moving from 16:30 to 19:00. This scenario implies a very complex management of the network as the PV generation will create ramps up to 1000 MW/h and 2000 MW/h (which can last 2 h) in the warm and cold seasons, respectively. Since Australia is still too dependent on coal-fired power plants which do not guarantee this flexibility, high levels of dissipation and energy losses may be necessary to maintain the boiler of these plants in pressure, losing so part of the environmental benefits which derive from RES.

The scenario characterised by a high adoption of BESSs (730 MWh in 2025 and 1860 MWh) coupled or integrated with PV systems (IPSS) in NSW showed that the contribution deriving from this storage technology will not support and reduce the PV impact from the centralised generation perspective. The ratio of the BESSs capacity to the daily PV generation will be lower than 6% and 10% during warm season in 2025 and 2035, respectively. Thus, it is clear that this level of penetration of BESSs in low-voltage feeders does not provide significant benefits to the centralised generation. In fact, the results of the simulation showed that the average maximum aggregated contribution that the network can experience is about 230 MW and 450 MW, in 2025 and 2035, respectively (the ramp of the demand do not change). This contribution is not enough to solve the problems such as peak shifting, peak shaving and valley filling, which are the main practices that the network operators try to realise to better smooth the demand. If on the one hand this level of penetration of BESSs does not help considerably the CG, the analysis of the impact that BESSs can have on a low feeder with a high penetration of PV systems may lead to results that are more significant.

In addition to the previous scenarios, the future impact of EVs has been analysed. The scenario was illustrated for the high sales forecasts. In particular, results showed that it is expected to have more than 600,000 vehicles in 2025 and about 2100,000 in 2035, which will contribute to increase the electricity demand during the night. In 2035, the charge of the vehicle was estimated to be 3.5 GW at midnight; this extra load will create a new night peak even higher than the morning and evening peaks, both during the warm and cold seasons.

In conclusion, in all the scenarios analysed, the future adoption of rooftop PV panels and impact on the CG are incredibly higher than the uptake of energy storage systems. Therefore, the impact on the demand will be driven by the behaviour of the PV systems. Only in the hypothetical scenario in which the installations of BESSs will assume comparable levels of the PV systems, it will be possible to better manage the centralised resources.

Compliance with ethical standards

Conflict of interest The authors declare no conflict of interest.

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