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A prospective economic assessment of residential PV self-consumption with batteries and its systemic effects: The French case in 2030

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ABSTRACT

The coupling market dynamics of PV sector and Li-ion batteries enhances the economics of residential PV self-consumption. If residential PV self-consumption systems become economically competitive in the near future, end-users will be willing to switch to PV self-consumption instead of using power from the network. However, if this transition were to occur massively or suddenly, the national energy system would be faced with a radical change. Our study has shown that French residential PV systems combined with Li-ion batteries could become profitable for individual investors before 2030. The demand in the residential sector would thus be natural in the near future in France. However, massive PV integration raises new issues for electricity system stakeholders (e.g. profit losses for traditional power generators, grid management, and sub-optimisation of the power system). This study has shown that PV self-consumption with batteries has a smaller impact on the power system than full grid injection. It is also shown that rapid integration is more costly than the progressive option with regard to PV system integration. We thus recommend a regular and progressive policy when transitioning to PV self-consumption to allow enough time for stakeholders to adapt to the new market situation.

1. Introduction

The PV sector has demonstrated visible progress over the last decade, reaching more than 300 gigawatts (GW) of installed capacity in 2016 (IEA PVPS, 2002–2015; Solar Power Europe, 2017). The reduced cost of PV modules has helped enhance the economic competitiveness of PV systems. End-users have economic incentives to adapt the mode of PV electricity self-consumption so as to reduce their electricity bills compared with the conventional way of purchasing electricity from the grid.

If residential PV systems coupled with batteries become economically competitive with a high ratio of self-consumption in the near future, end-users will be willing to switch to the self-consumption of PV electricity instead of using power from the network. A rupture (or radical change) could impact the national power system if the transition of PV self-consumption in the residential sector occurs massively or suddenly. Such change will influence the interests of the electricity market stakeholders and can be problematic for the national energy system. Policymakers would therefore have to focus on an optimal mix of PV power to achieve a careful balance with the other energy technologies. This is why policymakers need to understand the timing of this transition in order to detect any changes and to anticipate any transformation.

In this context, this study sets out to forecast any radical changes in the residential sector and discuss the role of policy. The article first assesses the future economic attractiveness of French residential PV systems coupled with lithium-ion (Li-ion) batteries in 2030. It gives a late threshold date since the evaluation is based on the French case where the electricity tariffs are relatively low and the residential PV system prices are higher. We then conduct a sensitivity analysis based on the key parameters used to define the LCOE estimates. The possible systemic consequences of a massive shift toward this solution are subsequently explained. The systemic effects of integrating PV into the power system have also been analysed. The ultimate objective is to help policymakers forecast possible scenarios for PV self-consumption so they can prepare for the future transition with strategic actions. By way of conclusion, we discuss the policy implications and elaborate policy recommendations based on the results of this study.

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2. Research context

2.1. Solar PV energy in power systems according to IEA scenarios in 2030

The Paris Agreement defined the international climate objectives to keep the mean global temperature rise to well below 2 degrees above pre-industrial levels and to limit the temperature rise even further to 1.5 degrees above pre-industrial levels (UNFCCC, 2015).[1] Solar PV energy is highlighted as a solution making it possible to meet such objectives. According to the IEA hi-renewable (hi-Ren) scenario, 16% of the global electricity will be supplied by solar PV power by 2050. This study was based on two IEA energy scenarios (IEA, 2014a, 2014b) to estimate the PV system prices in 2030: 2DS and hi-Ren. The IEA 2 degree scenario (2DS) proposes a radical energy system transformation to reach a mean global temperature rise limited to 2 °C by 2100 (IEA, 2014b). Furthermore, the IEA hi-Ren scenario[2] suggests that even greater efforts are required to shift to a low-carbon energy system based on the larger integration of renewable energies.

Table 1 illustrates the IEA solar PV goals with respect to the PV installed capacity and PV electricity generation by 2030 and 2050. Supported by the political efforts of many countries aiming to reduce their carbon footprint or to increase their energy independence, the PV sector is currently on track to meet the 2DS target (IEA, 2016).

Table 1
IEA's solar PV targets for 2030 and 2050.

	Actual	2DS		Hi-Ren	
Year	2015	2030	2050	2030	2050
Installed PV capacity	227 GW	841 GW	2785 GW	1721 GW	4674 GW
PV electricity generation	285 TWh	1141 TWh	3824 TWh	2370 TWh	6300 TWh

2.2. Literature review of PV self-consumption

The self-consumption of photovoltaic power in buildings is becoming increasingly relevant in the context of the energy transition. Self-consumption refers to the direct use of PV electricity on the same site where it is produced, with a smaller amount of electricity fed into the grid. PV self-consumption can imply many different solutions, from stand-alone off-grid systems in rural regions to the local consumption of smart energy systems. Thus, the literature on self-consumption is diverse, encompassing a wide range of technologies and systems.

A combination of increasing grid power costs, decreasing PV system costs and reduced feed-in-tariffs (e.g. the German EEG, (EPIA, 2013)) provides enough economic incentive to encourage PV self-consumption (Merei et al., 2016; IEA-RETD, 2014). The concept of prosumers (producers and consumers) is important in defining the concept of PV self-consumption in electricity systems since customers become more proactive with respect to power consumption by installing solar PV panels and managing their energy bills. The power sector is transforming from the traditional centralized system to locally presuming systems (Lavrijssen and Carrillo Parra, 2017; Parag and Sovacool, 2016).

The ratio of self-consumption, which defines the rate between onsite consumption and the total production of the system installed on the site, is a very important factor for defining the economics of the PV self-consumption model. The degree of PV self-consumption differs according to the power consumption profile in buildings. Unlike industrial or commercial sectors, however, the degree of self-consumption is smaller in separate residential systems because of a low correlation between onsite consumption and PV system output (EPIA, 2013; Quoilin et al., 2016). Luthander et al. (2015) explained that the level of self-consumption can be increased through methods like demand-side management or coupling with storage technologies.

Kyriakopoulos and Arabatzis (2016) have described a range of energy storage technology choices available for power generation. Diouf and Pode (2015) indicated that lithium-ion batteries can be a promising technology in the context of renewable energies. Driven by the need for mobile devices, together with the emerging electrical vehicle (EV) markets, the lithium-ion (Li-ion) battery technology has shown remarkable progress. The capital costs of Li-ion batteries are expected to fall over the next few years (Deutsche Bank, 2016; Beetz, 2015). This possible cost reduction makes the large-scale deployment of PV systems in the residential sector a feasible solution. Merei et al. (2016) has shown the profitability of PV self-consumption for the commercial sector can be enhanced by combining it with batteries on the condition that the battery costs can be reduced to €200/kW h in the future. Regarding the residential sector, Braun et al. (2009) has shown in the French-German Sol-ion project that the use of the lithium-ion technology increases PV self-consumption without changing user consumption habits. They calculated that the system could become profitable if the cost of Li-ion batteries fell under €350/kWh.

More recently, Eusebio and Camus (2016) claimed that residential PV systems with battery back-up power reached grid parity in Portugal following the decrease in battery prices. In addition, Shah et al. (2015) mentioned the potential of using off-grid residential hybrid energy systems (solar PV, battery, and combined heat and power) to address the national energy transition and system integration. In addition, Yu (2017) analysed the socio-economic benefits of off-grid PV systems with batteries in less-developed regions like Africa and South East Asia. Some studies provided insight into optimal sizes of residential distributed batteries (Weniger et al., 2014; Huld et al., 2014; Partlin et al., 2015).

Various factors should be taken into account to explain the decision of customers to adopt renewable energy technologies (Luthra et al., 2015). Reddy and Painuly (2004) provided a set of barrier groups for the penetration of renewable technologies: lack of awareness, financial, market, technical, institutional and behavioural. Sen and Ganguly (2017) stated market failures, awareness, socio-cultural aspects, and policy as barriers of renewable energy development. Sommerfeld et al. (2017) indicated the importance of correctly understanding consumer behavioural patterns with respect to PV self-consumption to guarantee the accuracy of future PV policies. Social feasibility (Kimura and Suzuki, 2006; Sen and Ganguly, 2017) or individual desire for greater energy autonomy (IEA-RETD, 2014; Yu and Popiolek, 2015) should not be ignored when explaining the consumer decision-making process. For example, Tsantopoulos et al. (2014) analysed the attitude of citizens to installing photovoltaic systems. The study found that Greek citizens were sufficiently willing to invest in photovoltaic systems either residentially or on a plot of land, though their motivation was quite different according to their income level and education. However, the economic driver is one of the key aspects behind the decision of residential end-users to use PV self-consumption (Sommerfeld et al., 2017; Reddy and Painuly, 2004; IEA-RETD, 2014).

In addition, some studies highlighted the importance of a systemic approach to assessing the economics of PV systems with regard to PV integration (Keppler and Cometto, 2012; Hirth, 2014). For example, Keppler and Cometto (2012) provided comprehensive insight into the technical and economic aspects conditioning the high penetration of PV power.

In this context, this study aims to assess the economic feasibility of

[1] Articles 2 and 4.

[2] The scenario is a variant of the 2DS model, assuming the slower deployment of nuclear energy, the delayed introduction of carbon capture and storage (CCS) technologies and the more rapid deployment of renewables, notably solar and wind energies.

residential PV self-consumption in 2030 to predict the future demand. The analysis goes as far as to include the assessment of systemic consequences on the electric power system.

2.3. Economic competitiveness of residential PV systems in France

The rapid decline in PV system costs is closely associated with the economics of PV self-consumption. Over the past few years, the PV market has largely gained in price competitiveness. Faced with the globalisation of the sector, the reduced cost of PV modules has helped improve the economic competitiveness of PV systems (Yu et al., 2016). Fig. 1 indicates the historical variations in the PV residential system prices in several countries (IEA PVPS, 2002–2015).

The current costs of French residential PV systems vary depending on the type of system: building-integrated PV systems (BIPV) at $2.67/Wp[3] and building-attached PV systems (BAPV) at $2.05/Wp in 2015 (the BIPV cost is 30% higher than the BAPV cost for existing buildings) (IEA-PVPS France, 2016). French PV system prices are higher compared with its neighbouring countries and its electricity tariffs are relatively low. Since this article is based on an unfavourable French case, our economic calculation gives a late threshold date for PV self-consumption. In our study, the PV system prices in 2030 were estimated using the learning-curve approach based on the PV installation targets proposed by the IEA energy scenarios (see 3.2.3).

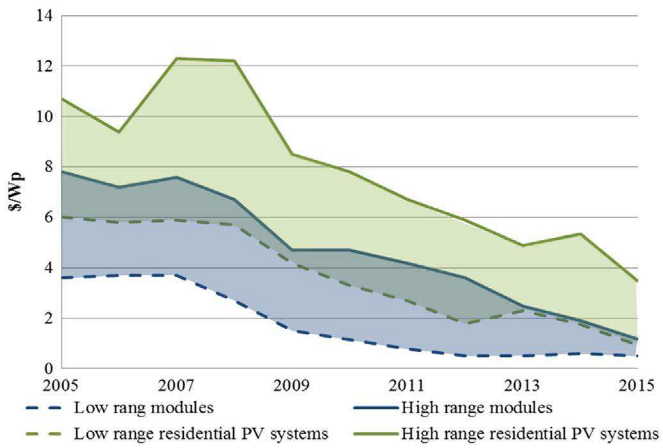

Fig. 1. Historical variations in the PV residential system prices in several countries (Author's elaboration based on IEA PVPS data).

2.4. Impact of the cost dynamics of Li-ion batteries on residential PV self-consumption

2.4.1. Projection of residential Li-ion battery costs

The study aims to define the future economic feasibility of residential PV systems. It is thus important to examine battery cost trends as a complementary measure to increase the ratio of self-consumption. This article has considered lithium-ion batteries, which is one of the most developed storage technologies with a potential cost reduction by economies of scale in the near future. They have changed rapidly with the development of mobile devices over the past decades, leading to the remarkable reduction in their volume and price. The ability of Li-ion batteries to be coupled directly with distributed PV systems can give a comparative advantage to residential systems if economically feasible. Many other promising storage technologies exist (Kyriakopoulos and Arabatzis, 2016), however, our analysis with Li-ion batteries can provide a basic scenario to define the potential opportunities for the large deployment of PV systems coupled with batteries in the future electricity mix.

Fig. 2 shows the different estimates of Li-ion battery prices[4] in the future. The estimated battery price would drop below $200/kWh between 2020 and 2025. In addition, the price would fall further between $100/kWh and $150/kWh in 2030 with a stabilised price. These reduced battery prices would create synergies with respect to the residential or commercial usage of the PV systems. In this regard, our calculation considered a price of $500/kWh in 2015 and a price of $150/kWh in 2030.

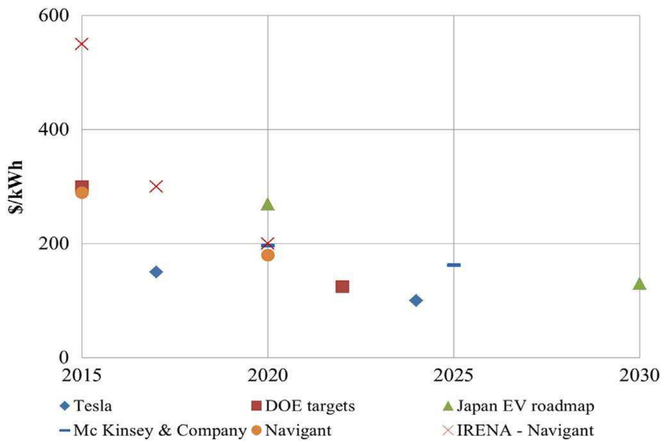

Fig. 2. Li-ion battery price projections (Author's elaboration based on literature review).

2.4.2. Higher PV self-consumption ratio with batteries

The poor correlation of PV self-consumption in the residential sector can be improved by combining it with storage systems. Fig. 3 illustrates the principal of using residential PV batteries. They can be used to store the electricity so it can be distributed when there is demand. It is important to properly define the system's optimum size to achieve a significant level of PV self-consumption in the residential sector. A small-sized PV system compared with the electricity demand profile is more likely to be completely self-consumed without storage solutions, but the gains with respect to the total onsite consumption will be small. However, a large-scale PV system will require a large amount of storage capacity leading to high capital costs. There is very little research and

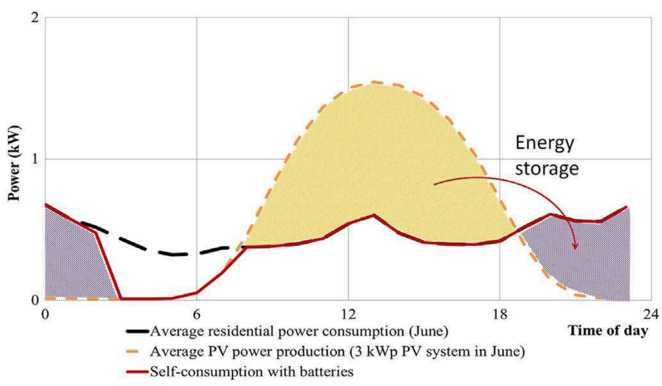

Fig. 3. Principal of using residential PV batteries (Author's elaboration).

[3] ~ €2.4/kWh.

[4] Tesla proposed a battery system for residential usage in 2015; the price of Tesla's Powerwall is $3500 for 10 kWh and $3000 for 7 kWh (Tesla motor). If the installation cost is included, the Deutsche Bank estimated the cost of the battery at $500/kWh (Deutsche Bank, 2016). According to the Deutsche Bank's report, Telsa's price will be reduced by 57% to $150/kWh in 2017 and by 71% to $100/kWh in 2024 (Deutsche Bank, 2015). The Japan EV roadmap aims to reduce the battery price to $270/kWh in 2020 and $130/kWh in 2030 (The committee on climate change, 2012). Furthermore, Mc Kinsey & Company expected the price of Li-ion battery packs to reach $197/kWh in 2020 and $163/kWh in 2025 (Hensley et al., 2012).

very few articles pertaining to the French context. For this reason, we based our analysis on German studies (Weniger et al., 2014; Huld et al., 2014; Partlin et al., 2015). Germany has similar climate conditions (e.g. insolation) and a similar consumption profile to France. However, France uses more energy in the residential sector because of the use of electrical heating. This difference was, however, ignored in our study since electrical heating is mainly used in winter when batteries are not essential. Therefore, the PV self-consumption ratio remains quite similar, even if the self-sufficiency ratio is lower.

Our study considered the use of 3 kWp PV systems, which are commonly installed in the residential sector. It was assumed that the combination of 3 kWp PV systems with 4 kWh Li-ion batteries provided an optimal solution up to 80% PV self-consumption for an average household that consumes around 4000 kWh/year of electricity.

2.5. Research objectives

Until recently, the objective of PV diffusion policies was mainly to create the market to help reduce PV costs, while inciting technological progress and industrialisation. PV market development in the near future is set to differ as a result of the sharp decline in the price of PV systems, related services and related products like lithium-ion batteries. Combining PV systems with batteries increases the self-consumption ratio of distributed energy and opens up new opportunities for associated services. The demand for electricity is price-inelastic, which means that minimising the costs is a way of maximising the utility of end-users.

In this regard, this study first aims at determining the economic attractiveness of the PV self-consumption model combined with lithium-ion batteries in the French residential PV sector in 2030. We based our study on the current market design. The objective of this article is to predict any possible radical changes in the near-future energy system due to PV self-consumption in France. The large penetration of PV power driven by its cost reductions may in fact result in higher systemic costs. The systemic effects directly associated with the power system mainly concern the intermittency of PV power and the unique characteristics of the electricity supply-demand mechanism. For example, non-dispatchable variable PV power generates additional costs in terms of electricity network reinforcement and expansion, short-term supply-demand balancing and back-up capacity (Keppler and Cometto, 2012) (see. 3.3). Therefore, the article also examines the systemic effects and potential risks caused by a massive transition towards PV self-consumption. We considered a time frame up to 2030. This article has attempted to address the following questions.

- What are the costs for French residential PV self-consumption systems coupled with lithium-ion batteries in 2030?
- What is the potential aggregate demand for residential PV self-consumption in France?
- What kind of systemic effects will there be with respect to the different scenarios?

At the end of this article, we have discussed the policy implications and given a few policy recommendations based on the results of this study.

3. Modelling methodologies

3.1. Schematic dynamic model of residential PV self-consumption with batteries

A schematic dynamic model of residential PV self-consumption was developed to analyse the pattern of consumer behaviour and ripple effects in the event PV power generation costs become more attractive in the near future. The current energy system is composed of several stakeholder groups. It is important to have an overall understanding of the different stakeholder viewpoints (Bryson, 2004) in the electricity systems when the transition to PV self-consumption happens.

End-users (*prosumers*) have economic drivers that encourage them to install PV systems for their own use, i.e. they can reduce their electricity bill or make money from the PV system. We evaluated the household profitability of investment in PV systems.[5] This profitability analysis compares the generation costs of self-consumed PV electricity with the residential electricity tariffs. The aim is to determine the critical moment at which it becomes profitable to transition to PV self-consumption. As Fig. 4 shows, we identified several key drivers of solar PV economics. However, PV self-consumption diffusion changes the existing electricity market mechanism by influencing other stakeholder interests. Stakeholders (the *latent group*[6] in particular) with little interest in the PV sector but with the power to seriously disrupt PV development should be closely examined. When PV policies to promote self-consumption are expected to conflict with the interests of these stakeholders, they will strongly oppose the policy-making process and disturb the development of the PV self-consumed model (Energy and Policy Institute, 2014). For example, the large diffusion of PV self-consumption can reduce the revenue of conventional power production companies and grid operators (Ueckerdt et al., 2013; Yu and Popiolek, 2015) as fewer PV self-consumers buy electricity from the grid.

The remaining part of this article addresses the perspectives of different stakeholders in the electricity systems. It first determines the economic attractiveness of PV self-consumption from a household perspective to understand the individual investment decision-making process. The article then examines how the PV dynamics change the existing electricity market mechanism (systemic effects) and influence other stakeholder interests (from the perspective of latent group). This ultimately aims to help policymakers predict any possible radical changes in the future energy system due to residential PV self-consumption and prepare strategic actions to address them.

3.2. Drivers of household investment decisions

3.2.1. Profitability of households

Profitability is a crucial determinant of household investment decisions when predicting the future demand for PV self-consumption (Sommerfeld et al., 2017). Electricity end-users will become PV prosumers if the investment in PV systems for self-consumption leads to the electricity bill savings or a positive return on investment (ROI). In our model, profitability compares the generated earnings by PV self-consumption with the total expenses and other relevant costs (including tax, if applicable) incurred during a specific period of time. Earnings normally include both the avoided electricity bills and the revenue from selling the surplus of electricity or political support (e.g. PV self-consumption bonus or green certificates).

We defined the profit investment ratio (PIR),[7,8] as below:

[5] There are many other factors that can influence the decision of customers to adopt solar PV: e.g. technical, institutional and behavioural barriers, market failures, awareness, socio-cultural aspects, and policy. However, we considered this analysis falls outside the scope of the article.

[6] The latent group has little interest in the subject and high power in the electricity systems. It refers to a stakeholder analysis of PV self-consumption; see the author's article (Yu and Popiolek, 2015).

[7] A modification of the net present value method.

[8] With

E_{PV}^{t} : PV electricity produced in the year t. α : Self-consumption ratio. P_E : Electricity prices in case of self-consumption ($\alpha E_{PV}^{t} \times P_E$: electricity bill savings in the year *t*).

p_A: Self-consumption premium.

P_G: Purchase price of PV electricity surplus sent to the grid.

τ: Tax on PV electricity revenues.

I_{PV}^{t}: PV system investment in the year t.

O&M^{t}: Operation and maintenance costs in the year t (including the replacement of batteries).

r : Discount rate.

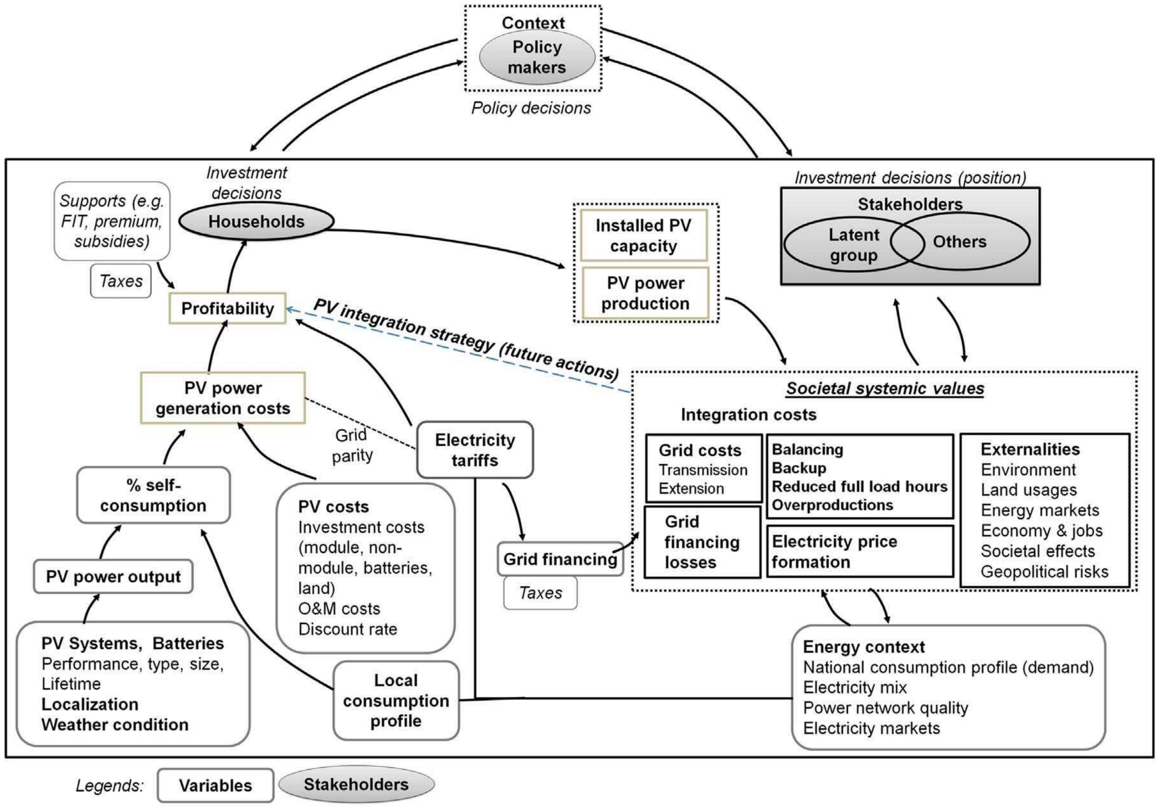

Fig. 4. Schematic dynamic model of residential PV self-consumption (Author's elaboration). The basic structures and specific explanation of the schematic model are described in the author's thesis (Yu, 2016)

$$\Pi = \frac{\text{Present value of cash flow over lifetime N years}}{\text{Initial investment required}} = \frac{\sum_{t=1}^{N} \frac{(\alpha E_{PV}^{t} \times (P_E + p_A) + (1-\alpha) E_{PV}^{t} \times P_G) \times (1-\tau)}{(1+r)^t}}{\sum_{t=1}^{N} \frac{I_{PV}^{t} + O\,\&\,M^t}{(1+r)^t} - \text{subsidies}} \tag{1}$$

If the model considers no value for the excess PV electricity and excludes tax, premium and subsidies, we can simplify the equation as below.

$$\Pi = \frac{\alpha \sum_{t=1}^{N} \frac{E_{PV}^{t}}{(1+r)^t} \times P_E}{\sum_{t=1}^{N} \frac{I_{PV}^{t} + O\,\&\,M^t}{(1+r)^t}} = \frac{P_E}{\frac{1}{\alpha}\text{LCOE}} \tag{2}$$

Break-even indicates the critical point at which it becomes relevant for households to install PV systems to reduce their energy bill. The investment will be considered when the index is greater than 1. The timing of break-even is directly related to the government's stance on PV self-consumption. For example, if the government prepares appropriate policy support and an institutional framework to provide favourable conditions for residential PV self-consumption, it can advance the break-even point and vice versa.

The definition of grid parity (or socket parity) needs to be reviewed to discuss the break-even of residential PV self-consumption (Eq. (2)). Grid parity often indicates a milestone for PV diffusion (Breyer et al., 2009; Breyer and Geriach, 2013). It happens when PV generation costs intersect with the price of retail electricity tariffs. PV grid parity for the residential sector was reached in some countries as a consequence of increasing residential electricity tariffs and reducing PV system prices (Weniger et al., 2014). However, electricity retail tariffs often include grid management costs and taxes. The comparison nevertheless remains relevant when discussing the momentum of residential PV self-consumption growth.

In addition, the household electricity tariff is a critical parameter for calculating the expected revenue of household (e.g. bill savings) (Masson et al., 2014). We thus compared the results with the estimated price of electricity in 2030 to anticipate the future demand. The methodological approach and data provided are described in greater detail in the next section.

3.2.2. Method for calculating the LCOE of solar energy

The levelised cost of electricity (LCOE) represents the lifecycle cost per kilowatt-hour (KWh) of building and operating power generation assets. The result is a break-even value that an investor would need to obtain per-kilowatt-hour (kWh) as the minimum sales revenue over the lifetime in order to justify the entire investment of a particular power generation facility (Reichelstein and Yorston, 2013). Solar PV power is commonly priced in terms of the LCOE ($/kWh) in many international studies (Fraunhofer ISE, 2015; IEA, 2014a; IRENA, 2015; EPIA, 2014) and scientific articles (Candelise et al., 2013; Hernández-Moro and Martínez-Duart, 2013; Reichelstein and Yorston, 2013) so the progress of PV technologies can be monitored easily.

Key inputs for calculating the LCOE include the investment cost, variable operation and maintenance (O&M) costs, fuel costs, financial costs, electricity output, plant lifetime and system performance. The energy production is calculated based on various parameters such as the lifetime, location, weather conditions, module efficiency, installation specification, and system performance. In our study, we added the costs of batteries[9] to evaluate the combined PV system costs for residential PV self-consumption. A simplified LCOE equation[10] for residential PV with batteries is indicated below.

$$\text{LCOE of the PV system with batteries} = \text{LCOE}_{\text{PV}} + \text{LCOE}_{\text{battery}}$$
$$= \frac{\sum_{t=1}^{n} \frac{I_{PV}^{t} + O\&M_{PV}^{t}}{(1+r)^{t}}}{\sum_{t=1}^{n} \frac{E_{PV}^{t}}{(1+r)^{t}}} + \frac{\sum_{t=1}^{n} \frac{I_{battery}^{t}}{(1+r)^{t}}}{\sum_{t=1}^{n} \frac{E_{PV}^{t}}{(1+r)^{t}}} \tag{3}$$

The LCOE method implies a high degree of sensitivity on the initial assumptions and parameters. Our study thus conducted a sensitivity analysis (Hernández-Moro and Martínez-Duart, 2013) of the PV cost assessment.

As the electricity system is very constrained, however, the large penetration of variable and non-dispatchable electricity sources influences the balance of the whole electricity system. The LCOE methodology is thus inadequate for assessing the market value of intermittent renewable energies like solar (Borenstein, 2012; Joskow, 2011; Keppler and Cometto, 2012; Hirth, 2014; Hirth et al., 2015; Ueckerdt et al., 2013). The LCOE approach can nonetheless be used to estimate the profitability of the residential PV self-consumption model. The evaluation perspective can be broadened to include systemic effects of PV integration for the comprehensive economic assessment of PV electricity in a society. These effects are further discussed in Section 3.3.

3.2.3. Dynamics of PV costs and using the experience curve to project PV cost reductions

In this study, the experience curve method was used to estimate the PV price trajectories. The experience curve is an empirical approach to project a cost reduction in industries. The diffusion and adoption of technologies depend on how further costs are reduced through innovation and experience accumulation (Arrow, 1962). The experience curve (Yelle, 1979), also known as a learning curve, describes the correlation between the reduction in production costs and the level of experience (Neji, 1997, van den Wall Bake et al., 2009; Byrne and Kurdgelashvili, 2011; Boston Consulting Group, 1972; Abell and Hammond, 1979; Sharp and Price, 1990). The general rule for the experience curve[11] is that the cost goes down by a constant percentage (the learning rate) with each doubling of the total number of units produced. The experience curve is usually used for long-term strategic analysis rather than short-term tactic review; experience curves can be used to project future cost trends based on past cost reductions (Byrne and Kurdgelashvili, 2011).

PV modules have demonstrated a consistent feature of 'learning-by-doing' over the last decades. The global PV module market now takes advantage of the cumulative knowledge stock and experience, thereby sharing a similar price of around \$0.5/Wp in 2016 (PV magazine, 2016; IEA PVPS, 2016). The positive correlation between the module's price drop and the size of the cumulative installations has been demonstrated in many studies, with the PV module's learning rate ranging between 18% and 22% in most literature (Timilsina et al., 2012; Reichelstein and Yorston, 2013; IEA, 2014a; Kersten et al., 2011). However, the learning experience for complete PV systems is usually considered slower than that for the modules because of local variations in non-module costs (Yu et al., 2015). We thus considered that the observed 'learning-by-doing' trend of solar PV technologies would remain regardless of the PV trajectory in the future system.

As indicated, our calculation is based on the IEA scenarios, which forecast world PV installations in 2030 with a focus on 2-degree scenarios (2DS) and hi-Renewable scenarios (hi-Ren).[12] We calculated the PV system prices in 2030 by using the learning curve with a learning rate of 18% (IEA, 2010, p. 18).

3.3. Systemic effects of PV integration in the electricity systems

3.3.1. Definition of systemic effects

A shift towards PV self-consumption in the residential sector will involve systemic effects in the power systems. The integration of PV power into the existing electricity systems requires additional efforts and costs (integration costs). Engineering efforts will be necessary to ensure the operation of all the physical systems while economic efforts will be necessary to ensure the systemic value of PV integration. The value evaluation of PV power in a society needs to be discussed in a more comprehensive manner by taking into account the systemic effects involved.

There are three levels with respect to the systemic effects of variable PV integration. The first level concerns the impact on the technical aspects like the infrastructure, grid and electricity production mix to maintain the operation of electricity systems (grid integration costs). The second level concerns the indirect financial impact of the regulatory mechanisms governing electricity systems, e.g. the electricity tariff system and electricity price formation. The last level concerns different types of externalities associated with integrating PV power into society. Various positive or negative aspects influencing the national system and social welfare should be considered: i.e. environment, technology, economy, jobs and strategic position. The higher the level of systemic effects, the broader the scope of analysis because of diverse correlations with other contextual, social or systemic variables.

In this context, our study was completed by a systemic analysis of the integration costs with respect to PV penetration into the electricity system. This is an important step in understanding stakeholder perspectives in relation to our PV self-consumption transition scenario. It helps policymakers prepare actions to counter any risks created by these stakeholders. Our study mainly focused on the systemic effects of PV integration related to power systems, which means the third level falls outside the scope of this study.

3.3.2. Literature review of integration costs

The systemic effects directly connected with power systems mainly concern the intermittency of PV power and the unique characteristics of electricity supply-demand mechanism. Variable PV electricity is not dispatchable and is unable to meet the electricity demand all year round. The value of electricity varies according to

[9] The battery yield losses were ignored.

[10] With:
I_{PV}^{t}: Investment in PV systems in the year t.
$I_{battery}^{t}$: Investment in batteries in the year t.
$O\&M_{PV}^{t}$: Operation and maintenance costs in the year t.
E_{PV}^{t}: PV electricity produced in the year t.
r: Discount rate.

[11] The mathematical model is described in Eqs. (4) and (5).

$$C_t = C_0 \times \left(\frac{X_t}{X_0}\right)^{-b} \tag{4}$$

$$LR = 1 - 2^{-b} \tag{5}$$

With:
C_t: Cost of unit production at time t (\$/W). X_t: Cumulative production at time t (W).
b: Experience index: this is used to calculate the relative cost reduction ($1–2^{-b}$) for each doubling of the cumulative production.
LR: The learning rate: the fractional reduction in price expected as the cumulative production double.
Initial condition:
C_0: Reference cost, X_0: Reference cumulative production.

[12] The study excludes the 6DS scenario. 6DS is a base-case scenario based on the condition that the current trends continue; it projects that the energy demand will increase by more than two-thirds between 2011 and 2050. In addition, associated CO_2 emissions are expected to rise even more rapidly, pushing the global mean temperature up by 6 °C.

the time of production and the location because of the unique feature of electricity system. The integration of PV into the existing grid system requires additional efforts to deal with its intermittency compared with dispatchable technologies. Various studies have examined the integration efforts required for PV penetration and the dynamic impact on the electricity systems (Borenstein, 2012; Joskow, 2011; Keppler and Cometto, 2012; Hirth, 2014; Hirth et al., 2015; Ueckerdt et al., 2013).

Keppler and Cometto (2012) largely divided the systemic costs (grid-level costs) of PV integration into two parts: 1) additional investments to extend and upgrade the existing grid, and 2) the costs for increased short-term balancing and for maintaining the long-term adequacy of the electricity supply to integrate variable energies. Short-term balancing concerns the second-by-second balancing of the electricity supply and demand (e.g. real-time adjustment, day-before forecasting). It is closely related to the accuracy of the weather forecast and the predictability of supply and demand. The improved forecast and prediction would decrease uncertainty on the production planning and would enhance the management of the production capacities for a day. More importantly, the level of flexible capacity in the electricity mix and the size of the interconnected electricity system both influence the balancing task in terms of the instantaneous adjustment to match changes in demand. Therefore, countries with a large share of flexible technology capacities (e.g. hydropower) in their energy mix will have lower balancing costs.

Intermittent PV systems require the long-term dispatchable back-up capacity to meet the electricity demand at all times (Pudjianto et al., 2013; Keppler and Cometto, 2012). Non-dispatchable energies like PV contribute very little to generation system adequacy in Europe (the capacity credit of PV power in France is very low). The long-term back-up costs include investment and operation and maintenance costs to give additional adequacy capacities (demand increase) or to keep existing capacities available (constant demand); these costs are necessary to maintain a certain level of system reliability when variable energies are integrated into the electricity mix. The back-up costs account for the large fraction of the grid-level costs.

In another study, Ueckerdt et al. (2013) introduced the notion of system LCOE to evaluate the integration costs of intermittent energies. Ueckerdt et al. broke down the integration costs into grid costs (network costs), balancing costs (real-time balancing of supply & demand) and profile costs (adequacy, full-load hour reduction and over-production of variable electricity). The study is based on the load duration curve approach. The load duration curve method involves ranking the required power capacity for each unit of time (hour-to-hour) in decreasing order. A residual load duration curve can be obtained by subtracting the power generation from variable wind or PV resources. The optimal mix can be obtained by taking the minimum power generation costs into account to meet the annual electricity demand. The most critical segment of integration costs (variability) concerns the profile costs; the balancing costs are of secondary economic importance. The reduced rate of utilisation of conventional dispatchable plants led by the high penetration of renewable energies is a key issue when assessing the integration costs (Hirth et al., 2015). Ueckerdt et al. (2013) provided a mathematical method (Eq. (6))[13] to quantify the integration costs.

[13] With:

C_{int} : Integration costs of variable renewable energies (VRE).

C_{grid}: Costs of grid extension and upgrading, $C_{balacing}$: Balancing costs, $C_{profile}$: Profile costs.

C_{resid} : All other costs for the residual system with VRE integration (including generation costs of dispatchable plants, costs for reserve requirements, balancing services, grid costs and storage systems).

$C_{total}(0)$ Total costs to meet a system's demand without VRE generation. E_{resid}: Resulting residual load with VRE (provided by dispatchable power plants).

$\bar{E}_{total}$: Power system's annual power demand (exogenous factor).

$$C_{int} = C_{grid} + C_{balancing} + C_{profile} \text{ with } C_{profile} = C_{resid} - \frac{E_{resid}}{\bar{E}_{total}} C_{total}(0) \tag{6}$$

They introduced the concept of profile costs, which can be defined by comparing the cumulated costs to meet the residual power demand induced by PV penetration with the cumulated costs to meet the same residual demand calculated based on the current average production costs. If the residual demand curve is steeper than the current reference curve, the profile costs are positive and if the curve is flatter, the costs are negative. In addition, they provided considerable insight with respect to assessing the integration costs of variable energies by determining the speed of integration. The study explained the differences between short-term (ST) and long-term (LT) perspectives of variable renewable energy (VRE) integration. The short-term perspective involves the fast deployment of VRE without adaptation. The conventional dispatchable capacities remain unchanged after introducing VRE. In contrast, the long-term perspective assumes a complete power system transition. The dispatchable capacities have time to fully and optimally adapt to the integration of VRE with a new long-term equilibrium (optim). Ueckerdt et al. proposed new mathematical expressions to calculate profile costs according to these two cases (the sum of the lowest production costs to meet the residual power demand in Eq. (7) and the sum of the production costs based on the current mix to meet the residual power demand in (8)).[14] They make it possible to evaluate the effects of PV integration according to the speed of integration, i.e. short-term or long-term. Our study quantified PV integration costs based on this mathematical approach.

3.3.3. Other financial effects

As seen, integrating PV power into the existing electricity mix reduces the operation hours and the capacity factor of conventional dispatchable plants and eventually influences their profitability. This issue is critical because they are compulsory to maintain the security of electricity systems. The negative financial impact on existing dispatchable capacities can be discussed in relation to the formation of the current electricity price. The current management of the electric power system ranks the capacities in ascending order of marginal costs of production (merit order). The ranking is organised on the basis of the day-ahead declaration of available capacities. The

[14]

$$C_{resid}^{optim} = \int_0^{q_{peak}} T(q, \quad E_{VRE}) C_{min}(T(q, \quad E_{VRE}))dq \tag{7}$$

With:

C_{resid}^{optim} : Costs of residual system after VRE integration in a **long-term** perspective (the mix adapts in response to the transformation with VRE integration).

E_{VRE} : Power generation from VRE.

q_{peak} : Annual peak demand of electricity.

$T(q, E_{VRE})$: Full-load hours for power demand q.

$C_{min}(T(q, E_{VRE}))$: Generation costs from the cheapest production capacity (i.e. nuclear, gas and coal) to operate a full-load hours of $T(q, E_{VRE})$.

$$C_{resid}^{ST} = \sum_{te} \int_{q_{te,min}}^{q_{te,max}} T(q, E_{VRE}) C_{te}(T(q, E_{VRE}))dq \tag{8}$$

With

C_{resid}^{ST} : Costs of residual system after VRE integration in a **short-term** perspective (the dispatchable capacities remain unchanged, the mix is not able to adapt in response to the transformation).

te : Considered dispatchable power generation technologies (i.e. nuclear, gas and coal).

$q_{te,min}$ and $q_{te,max}$: The lower bound and the upper bound of the zone powered by technologies *te* respectively, on the vertical axis of residual load duration curve.

$T(q, E_{VRE})$: Full-load hours for power demand q.

$C_{te}(T(q,E_{VRE}))$: Generation costs of technologies *te* with a full-load hour value of $T(q,E_{VRE})$.

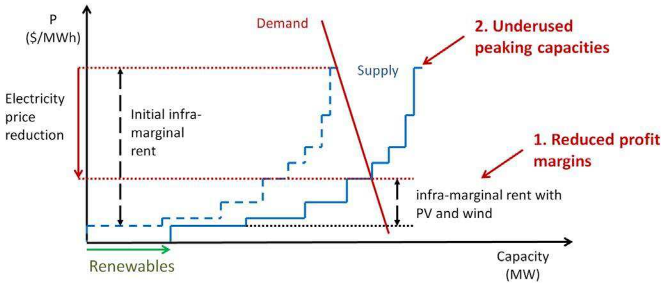

Fig. 5. Merit order and electricity price formation (Author's elaboration).

Table 2
Estimated residential PV system costs in 2030 based on the IEA scenarios.

	2015	IEA scenarios for 2030	
		2DS	Hi-Ren
World PV cumulated installations (GWp)	227	842	1721
BIPV system cost ($/Wp)	2.67	1.83	1.49
BAPV system cost ($/Wp)	2.05	1.41	1.15

Table 3
Estimated costs of 3 kW PV systems coupled with 4 kWh batteries in 2030 (based on the IEA scenarios).

Material costs	2015	IEA scenarios for 2030	
		2DS	Hi-Ren
4 kWh batteries	US$ 2000	US$ 600	US$ 600
3kWp BIPV systems	US$ 8010	US$ 5504	US$ 4485
3kWp BAPV system	US$ 6150	US$ 4226	US$ 3443

electricity price is determined by the highest marginal costs of production units to satisfy the demand. The price is imposed on all other producers. The base-load capacities have low variable costs and are ranked first (e.g. run-of-the-river hydroelectricity, nuclear). The

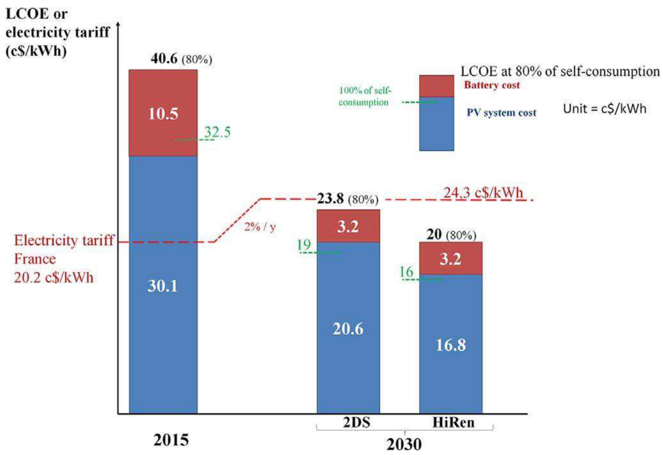

Fig. 6. Economic attractiveness of French residential PV systems coupled with lithium-ion batteries in 2030.

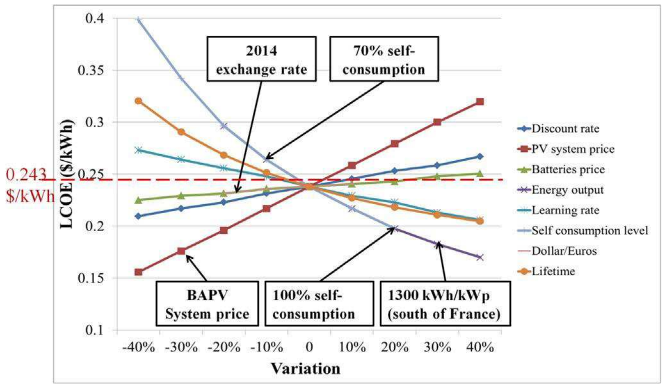

Fig. 7. Sensitivity analysis of PV LCOE estimates.

Table 4
Parameters of the sensitivity analysis.

Criteria	Nominal values	Ranges	
		Minimal values (−40% by default)	Maximal values (+40% by default)
PV system price	$1.83/Wp	$1.1/Wp	$2.56/Wp
Batteries price	$150/kWh	$90/kWh	$210/kWh
Energy output	1000 kWh/kWp	800 kWh/kWp	1400 kWh/kWp
Lifetime	20 years	12 years	28 years
Discount rate	5%	3%	7%
Learning rate	18%	11%	25%
Self-consumption level	80%	48%	100% (+20%)
Dollar/Euro exchange rate	0.9	0.72 (−20%)	0.99 (+10%)

peaking capacities have high variable costs and are ranked last (e.g. oil, gas).

PV electricity with zero marginal costs is ranked first in the merit order before base-load capacities and the merit order shifts to the right (Fig. 5). However, the electricity demand is inelastic; price variability does not have much impact on consumption. Therefore, the electricity price is reduced with the same demand curve (Haas et al., 2013; Commissariat Général à la Stratégie et la Prospective (CGSP), 2014). It raises an issue with the payment of the initial investment (*losses of infra marginal rent*). In addition, in terms of the temporarily reduced demand, it is sometimes technically too difficult to shut down a capacity for a short time only. This occurs when PV production is maximum (i.e. summer daytime). In extreme cases, the market price can be negative. It also concerns the reduced use of the peak capacities, which in turn reduces the revenue of conventional power plants. With the deterioration in the peak coefficient,[15] the extreme peaking capacities become an issue since they cannot cover their fixed costs (Hogan, 2005) (the missing money). This would thus exacerbate the problem in terms of future investment choices; investors are reluctant to build conventional plants because of the uncertainty in recovering the capital invested. This threatens the

[15] The peak coefficient is the ratio between the average hourly production during the year and the peak production (Heinen et al., 2011).

energy supply security.

Another issue should be discussed with regard to electricity tariffs. The shift to PV self-consumption induces loss of grid operator revenue (Yu and Popiolek, 2015). Electricity retail tariffs are often composed of various costs like electricity generation, grid management and taxes. The maximum grid capacity must be kept to maintain the security of power supply because of the low capacity credit of PV. Grid operators will have to engage in more activities to manage the integration of variable PV energies which explains why it is important to secure the budget for grid financing. However, there are risks related to electricity tariffs because hidden stakeholder revenue losses occur when fewer consumers purchase electricity from the grid.

4. Results and discussions

4.1. Costs for French residential PV self-consumption systems in 2030

4.1.1. Prospect of PV system cost reductions

In order to predict the PV power generation costs in 2030, we first estimated the PV residential system costs in 2030 using Eqs. (4) and (5). As indicated, our calculation was based on the costs of two types of French residential PV systems using c-Si PV technology, i.e. BIPV system cost of \$2.67/Wp and BAPV system cost of \$2.05/Wp and a learning rate of 18% (IEA, 2010, p. 18).

Table 2 presents the projected costs of residential PV systems in France in 2030.

4.1.2. Prospect of PV LCOE with batteries in the French residential sector in 2030 and profitability

We calculated the French residential PV LCOE[16] combined with batteries in 2030. In order to define the investment costs, the cost of 4 kWh batteries was added to the estimated cost of the 3 kWp BIPV systems (Table 3). For example, the cost would be around US\$ 5100 in 2030 in order to acquire a 3 kWp BIPV PV system with 4 kWh batteries according to the Hi-Ren scenario.

Fig. 6 shows the calculated PV LCOE of 80% self-consumption in 2030 according to different scenarios. The profitability of PV systems with batteries was also considered. As explained, the profitability ratios provide a comparison between the LCOEs of PV systems[17] with batteries and the residential electricity tariffs. It determines the critical point at which it becomes relevant for households to install PV systems to reduce the energy bills.

We compared the results with the estimated price of electricity in 2030. Our study was based on the current market design. We thus assumed that the electricity tariffs increased by 2% per year until 2030. The electricity tariffs for households in 2015 were \$US 0.18/kWh in France (€0.1624/kWh) (Eurostat, 2016). If we consider a 2% increase by year, the household tariffs in 2030 will be \$ US 0.243/kWh in France. However, a high level of uncertainty exists when there are radical changes in the market system.

It should be noted that the considered PV systems with batteries are currently far from reaching the break-even point in France, but they would become competitive in France by 2030 under all IEA scenarios. However, if the global number of PV installations grows faster than the assumptions based on the IEA scenarios or if targeted policies to reduce soft-costs are implemented, residential PV systems with batteries can become profitable in France before 2030 (Fig. 6), especially in the southern part of France which benefits from higher insolation. This will be further explained in the sensitivity analysis in the next section.

In addition, battery prices are expected to continue to decline. Our analysis showed that battery prices will represent a small fraction of the PV power production costs of residential PV systems combined with batteries. Based on the 2DS scenario, it will only account for about 13% of the PV power production costs amounting to only c\$3.2/kWh in 2030. With a self-consumption rate of around 80%, the surplus electricity is small. If PV policies aim to promote self-consumption, it is also conceivable to establish a mechanism for reselling the 20% surplus to the network in order to enhance its economics. Since our study aims to evaluate the economic feasibility of residential PV self-consumption with batteries without political financial incentives, we decided to exclude the surplus of PV system output in our study. In addition, the impact of grid injection of excessive PV power on the power systems will vary depending on how the batteries are charged (e.g. charging speed, charging duration, time-lagged charging by geography, etc.). We considered that this point fell out of the scope of our study.

4.1.3. Sensitivity analysis of residential PV LCOEs in 2030

We conducted a sensitivity analysis for eight of the most crucial parameters that define the LCOE estimates of PV systems with batteries in the French residential sector. The analysis using a spider chart is shown in Fig. 7. Each line represents one of the parameters varying the nominal values according to different ratios. The 2DS scenario was used to calculate the base-case values. The chosen criteria are indicated in Table 4.

The slope of the line indicates the sensitivity of the PV LCOE estimates to the each parameter. The degree of sensitivity differs among these variables. The current PV system price, the energy output (insolation) and the self-consumption ratio have the greatest influence on the PV LCOE estimates. In contrast, the discount rate, the learning rate and the battery costs have a relatively low impact when it comes to defining the PV LCOE among the criteria we chose. For example, the battery costs have a relatively small impact because they get a low share of the future PV system prices.

Fig. 7 shows that our base case is a lower-bound case. The PV energy output was estimated based on the location of Paris, yet the conditions are much more favourable in southern France. In addition, French residential PV system prices are usually higher because of building-integrated PV systems (BIPV), yet building-attached PV systems (BAPV) are currently 30% cheaper (IEA-PVPS France, 2016).

Table 5 indicates the sensitivity of the profitability of PV systems with batteries. As previously explained, the profitability ratios compare the LCOEs with the residential electricity tariffs to anticipate the critical timing of transition to PV self-consumption. However, estimating the residential electricity tariffs does imply a certain level of uncertainty. The sensitivity analysis of the electricity tariffs can thus provide a comprehensive comparison. An annual increase of 2% was considered as the base scenario in our calculation.

[16] In order to calculate the LCOE of the French residential PV self-consumption model in 2030, we referred to the following data and assumptions.

PV system price: €1.83/Wp, building integration (BIPV) for residential rooftops using c-Si PV technology.

Potential PV power output: 1000 kWh/kWp/year provided by PVGIS (JRC European Commission) (almost equivalent to the irradiation of Paris, lower bound for France) based on optimal positioning, c-Si cells, and estimated system losses of 14%.

O&M: 1.5% of PV system price (European Commission, 2013).

Lifetime: 20 years for the PV system and 10 years for the battery (Mundada et al., 2016). We considered the repurchase of batteries with the same replacement costs.

A discount rate of 5% was used to consider the weighted average costs of capital (WACC) for the respective investment (European Commission, 2013; Fraunhofer ISE, 2013).

[17] The LCOE of residential PV systems with batteries divided by the ratio of self-consumption.

Table 5
Profitability sensitivity (2DS scenario).

Electricity price variation	−40%	−30%	−20%	−10%	0%	+10%	+20%	+30%	+40%
Electricity price	0.146	0.170	0.194	0.219	0.243	0.267	0.292	0.316	0.340
Profitability with LCOE = 0.238 $/kWh	0.61	0.71	0.82	0.92	1.02	1.12	1.23	1.33	1.43

4.2. Risks of transitioning to PV self-consumption and systemic effects

4.2.1. Risks of transitioning to PV self-consumption

We concluded that PV systems would become profitable for individual investors in France by 2030 under the IEA scenarios in question with a self-consumption rate around 80% led by the use of batteries. It is possible to advance the time if the economic analysis considers more favourable assumptions and input data (e.g. insolation in Southern regions, BAPV systems).

A simple calculation gives an upper limit of development opportunities in the French residential sector based on the coupling of PV systems with batteries. France has 33.4 million residential buildings, including 18.8 million individual houses (ADEME, 2013, p. 36), and the residential and tertiary sectors account for 44% of the national electricity consumption. If PV self-consumption in the residential sector helps reduce the energy bills of households, a massive and rapid transition towards PV self-consumption can occur in the near future.

If 18.8 million individual houses installed a PV system with an average capacity of 3 kWp, it would represent a potential additional installation of approximately 56 GWp producing PV electricity of about 46 TWh[18] per year. This accounts for around 10% of the French electricity consumption, which was 476 TWh in 2015 (RTE, 2016).

As explained in Section 3.3, the network must meet the demand that can be requested when PV power plants are unavailable. The massive integration of PV power into the power system thus includes risks that are mainly related to grid management because of intermittency issues. This also includes risks of seeing the sub-optimisation of electricity system with the massive and uncontrolled deployment of PV self-consumption. In this regard, the government wants to be able to properly anticipate all kinds of risks related to PV development in the future to avoid any negative consequences. We thus analysed the systemic effects of PV integration in the following section. France decided to reduce its share of nuclear power to 50% by 2025 (République Française, 2015a). However, the final framework to reach the targets has not yet been defined. The analysis has been conducted based on the current 2015 French electric power consumption and nuclear capacity. This approach helps policymakers prepare strategies to mitigate risks related to PV self-consumption growth in the future.

4.2.2. Systemic effects of PV integration

We attempted to quantify the reduction in the load duration curve of the existing power capacities influenced by the demand growth for PV electricity in the French residential sector and the resulting profile costs.

This study has taken two variables, i.e. the speed of PV integration and the use of batteries, to determine different scenarios in terms of adding 56 GWp installed capacity of PV power (the defined aggregate demand). Four scenarios can be considered (Fig. 8).[19] Our residential PV self-consumption model with batteries concerns scenarios SR and scenario SP.

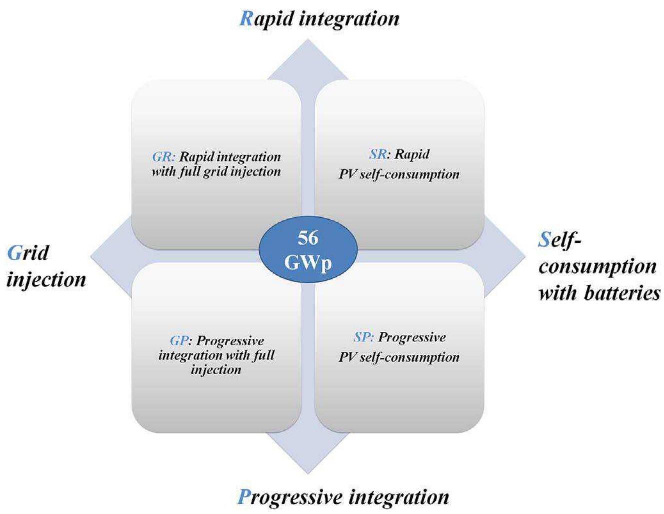

Fig. 8. Scenarios for PV integration in the electricity systems.

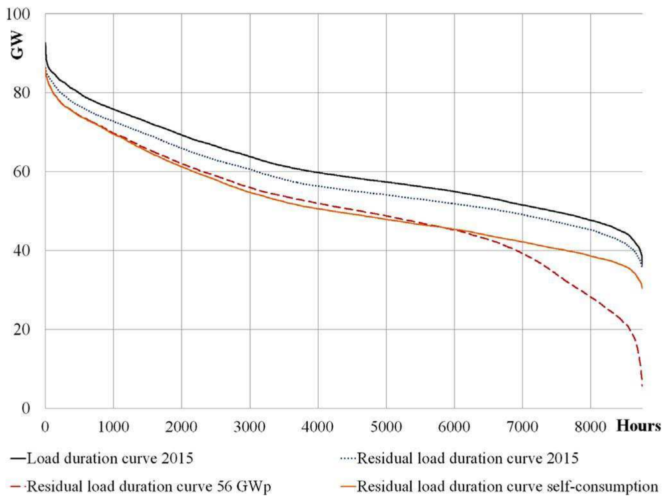

Fig. 9. Residual load duration curves.

4.2.2.1. Residual load duration curve.

As a baseline for the study, our simulation was based on the French PV cumulative installation capacity of 6.5 GWp in 2015, representing 1.6% of the domestic consumption (IEA PVPS, 2016). We then assumed that the maximum possible PV capacity, which was identified in the previous section (56 GWp), was added to the French electricity mix. We considered that wind production remained constant since the analysis of wind power integration falls outside of scope of this article. The PV production was estimated by extrapolating the current hourly PV production data from RTE (French transmission system operator) (RTE, n.d.).[20]

[18] 80% × 56 GWp x ~ 1000 kWh/kWp/year.

[19] **Speed R**: Rapid integration of PV power, uncontrolled installations (i.e. installation peaks), **Speed P**: Progressive integration of PV power (i.e. constant PV installations), **Usage G**: PV integration without batteries, full grid injection (i.e. utility-scale PV deployment), **Usage S**: residential PV self-consumption with batteries, no grid injection (~ 80% of self-consumption ratio, our PV self-consumption model).

[20] From 6.5 GWp in 2015 to 62.5 GWp in 2030.

Table 6
Investment and variable costs of the virtual electricity mix technologies.

	Nuclear plants	Coal plants	Combustion turbines (CT) (oil)	Combine cycle gaz turbines (CCGT)
Investment (k€/MW)	3910	1400	500	800
Lifetime (years)	60	40	25	30
Annual O&M (k€/MW/year)	75	30	10	20
Annualized fixed costs (k€/MW)	395	147	57	91
Variable costs (€/MWh)	10	52	162	66
CO_2 intensity (t/MWh)	0	0.32	0.27	0.27

Table 7
Optimal mix of power generation and reduction of annual full load hours of dispatchable capacities.

10% PV penetration (Rapid)	Optimal mix of power generation (virtual electricity mix in 2015)		Rapid integration case: Reduction of full load hours (56 GW added capacity)	
	Dispatchable capacities (GW) (Optimal)	Full-load hours /year (Optimal)	Reduced full load hours/year (Scenario Grid injection)	Reduced full load hours/ year (Scenario Self-consumption)
Nuclear	52	Over 5920	Over 3979	Over 3641
Coal	10.8	2507–5920	1878–3979	1869–3641
Combine cycle gaz turbine (CCGT)	15.3	357–2507	195 to 1878	193–1869
Combustion turbine (CT)	8.1	0–357	0–195	0–193

Table 8
Dispatchable capacities in the optimal mix of power generation.

	Optimal mix of power generation (virtual electricity mix in 2015)		Progressive integration case: reduced optimal capacities of dispatchable units	
	Dispatchable capacities (GW) (Optimal)	Full-load hours/year (Optimal)	Scenario Grid injection, GW	Scenario Self-consumption (no grid injection), GW
Nuclear	52	Over 5920	45.5	45.8
Coal	10.8	2507–5920	13.4	12.5
Combine cycle gaz turbine (CCGT)	15.3	357–2507	17	17.5
Combustion turbine (CT)	8.1	0 to 357	10.2	10.2

Table 9
Nuclear power production losses based on different scenarios.

Nuclear power production (TWh/year)	Grid injection (Scenario G)	No Grid injection (Scenario S)
Speed Rapid (R)	399 (−8%)	416 (−4%)
Speed Progressive (P)	367 (−15%)	387 (−11%)

This results in a significant reduction in the residual load supplied by conventional power plants. Fig. 9 indicates the yearly load duration curve (black line) and the residual load curve without PV and wind in the French electricity mix (blue dotted line) in 2015. The red dashed line represents the future residual load curve after adding a new installed solar PV capacity of 56 GW without batteries. The orange line indicates it for the residential PV self-consumption model with batteries. The residual production of the current mix represents 506 TWh[21] (2015), which will fall to 460 TWh according to our transformation scenario S (PV self-consumption with avoided grid injection), and to 444 TWh according to our scenario G (full grid injection).

As Fig. 9 indicates, the capacity of base-load power plants that operate continually during the year will be reduced once 56 GW of new PV capacity has been added. However, the increasing share of solar power in the system does not help reduce the annual peak demand in France because of the low capacity credit. As Fig. 9 demonstrates, the peak demand stays constant at 86 GW; about 6 GW of the peaking units are used for less than a hundred hours. Therefore, the induced shift to PV power reduces the profitability of the existing power plants, which means some producers will have difficulty recovering their investment in the facilities.

4.2.2.2. Optimal power generation mix. We can now determine the optimal power generation mix with respect to defined scenarios. Analysis was conducted based on a virtual electricity mix,[22] which is composed of a number of dispatchable capacities to satisfy the annual

[21] We included losses and exports compared with consumption. Our simulation was based on the electricity production data (assumption: production = demand). The total production in 2015 was 533 TWh.

[22] The French electricity mix has a large share of hydraulic power. However, this approximation based on a virtual electricity mix is commonly used in many studies of French electricity mix (République Française, 2009).

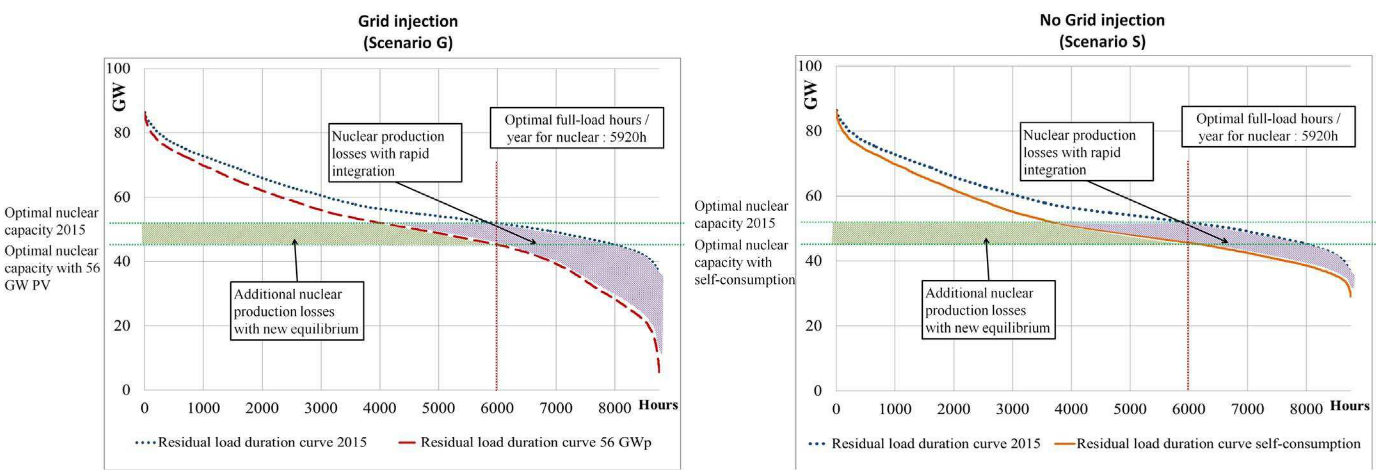

Fig. 10. Nuclear power production losses based on different scenarios.

power demand (see Table 6). The system usually includes nuclear or coal for baseload generating units, coal or gas for intermediate loads, and combustion turbines for peak load units. The assumed carbon price was €30.5/ t CO_2, equal to the carbon price of 2017.

As seen, the defined aggregate production of 56 GW PV is equivalent to 10% of the electricity demand in France. The annual power demand and wind power were assumed constant within the simulation.

Table 7 indicates annual full-load hours of dispatchable capacities in the optimal power mix and the consequences of a rapid integration of PV power. According to our self-consumption model with batteries, the batteries are charged up to the maximum capacity (4 kWh) in case there is a surplus[23] of PV electricity and discharged when consumption exceeds production. In our study, we also assumed that the excess PV power would be lost once batteries were fully charged.

The rapid penetration of PV power decreases the yearly full load hours of existing conventional capacities and leads to the sub-optimisation of the electricity mix.

The simulation produces different results when PV integration is conducted in a progressive manner to achieve the same level of PV penetration. The power generation mix obtains a new long-term equilibrium (*optim*).

Table 8 shows new optimal capacities of dispatchable units in terms of the full grid injection scenario (Scenario G) and the self-consumption (Scenario S). For both scenarios, the PV integration decreases the nuclear capacity by around 12% and increases the capacity of the peaking units (by around 26% for combustion turbines) (Table 9).

The increasing level of renewable energy integration tends to decrease the market size and the revenue of conventional power producers. The French power system comprises a high share of nuclear power, representing 63.1 GW in 2015. Nuclear power supplied 76.3% of the French domestic electricity production in 2015 (RTE, 2016). If we assume a constant level of nuclear power plant availability[24] in a year at 80% (CRE, 2016a) the available nuclear capacity is 50.5 GW and it is almost equal to the nuclear capacity of our virtual electricity mix (52 GW).

We estimated the losses of French nuclear power production; our calculations considered the nuclear power production in 2015 (434 TWh) as a baseline for comparison.

Based on our residential PV self-consumption model with batteries (Scenario S), the power production from nuclear plants is reduced by 18 TWh (−4%) to 47 TWh (−11%). This impact will intensify under the scenario without batteries (Scenario G); the residual load duration curve will become steeper and the nuclear capacity is operated well below the optimal level (Fig. 10).

The possible shift from nuclear power to fossil fuels will exacerbate CO_2 gas emissions. In this regard, our study also found that a carbon price of €93/ t CO_2 makes it possible to maintain the same level of nuclear power in the optimal mix.[25]

4.2.2.3. Integration costs of PV power. Based on the results obtained, we attempted to quantify the integration costs of PV power in the electricity mix according to the defined scenarios. Our analysis assumed that the PV integration costs were composed of grid-related costs, balancing costs and profile costs.

4.2.2.3.1. Grid related-costs and balancing costs. The direct costs of PV integration concern grid-related costs (i.e. grid reinforcement or extension) and short-term balancing costs. A number of studies estimated these costs (Keppler and Cometto, 2012; Pudjianto et al., 2013). For example, with a 10% PV penetration level in France, grid-related costs mainly for utility-scale PV plants were estimated at around \$5.8/MWh and balancing costs at around \$2/MWh (Keppler and Cometto, 2012) without a PV integration strategy. Grid-related costs will become almost null under the residential PV self-consumption model with batteries if the significant injection of electricity into the electrical grid can be avoided (Table 10). Short-term balancing costs can be minimised through geographic spread; this reduces uncertainty in the forecasts of PV power production (statistical effects).

4.2.2.3.2. Profile costs. We adopted the method proposed by Ueckerdt et al. to quantify the integration dynamics caused by the residential PV self-consumption model. The mathematical expressions (7) and (8) were used to calculate the profile costs ($C_{profile}$), which account for the significant part of PV integration costs (C_{int}).

We took the date of 2015 as a baseline to estimate the profile costs. We assumed that the annual power demand ($\overline{E}_{total}$) in 2015 was equal to the residual electricity production in 2015 (including losses, exportations and storage but excluding wind and solar production). In order to calculate $C_{tot}(0)$ and $C_{profile}$, the virtual electricity mix was considered.

[23] The profitability of the residential PV self-consumption model can be greatly improved if the excess PV power is sent to the grid with financial benefits. In this case, however, the profile costs can increase because the surplus PV power is mainly produced during a few days in the summer. The impact varies according to the way the batteries are controlled. This analysis falls outside the scope of the article.

[24] Availability was measured based on the availability factor that indicates the average availability of the nuclear power plants in a year. This coefficient takes into account the capacities that cannot generate power due to maintenance.

[25] Carbon pricing targets in the French energy transition act (2015): €56 per tonne by 2020 and €100 by 2030 (République Française, 2015b).

Table 10
Grid-related costs and balancing costs.

	Grid injection (Scenario G)	No Grid injection (Scenario S)
Grid-related and balancing costs	~ 8 \$/MWh	~ 0 \$/MWh

Table 11
Profile costs based on different scenarios.

Profile costs	Grid injection (Scenario G)		No Grid injection (Scenario S)	
Unit	Billion €/year	€/MWh PV	Billion €/year	€/MWh PV
Speed Rapid (R)	2.3	33.8	1.4	26.7
Speed Progressive (P)	2.0	29.4	1.1	19.8
Reduction ratio (R vs. P)	−15%	−13%	−35%	−26%

Table 11 shows the profile costs of 56 GW PV integration depending on different scenarios. The annual total profile costs and the unit costs per megawatt-hours (\$/MWh)[26] were presented.

According to our analysis, the maximum additional cost per each MW installed amounts to €33.8/MWh under Scenario G with the rapid integration of PV power. The price can be almost reduced to €19.8/MWh with progressive PV integration based on our PV self-consumption model with no grid injection. It is important to point out that the speed of PV integration is a significant factor for determining the profile costs. Rapid integration is more costly than progressive deployment: about 13% higher for PV integration with grid injection (Scenario G) and about 26% higher for residential PV self-consumption with batteries (Scenario S). As seen in Fig. 9, PV integration with grid injection (Scenario G) has a much steeper load duration curve than residential PV self-consumption with no grid injection for base-load units. When the residual load duration curve falls below zero, overproduction occurs during the year (PV power supply exceeds the load). According to Ueckerdt et al. (2013), this phenomenon is the most expensive part of PV integration costs. Our residential PV self-consumption model with batteries makes it possible to obtain higher levels of PV penetration before overproduction occurs. Therefore, it is important to take into account the integration costs with regard to the PV deployment decision.

4.2.2.4. Other financial effects

4.2.2.4.1. Indirect financial impact related to regulatory mechanisms of electricity systems. Fig. 11 presents the total current electricity consumption, PV production without storage and PV production with batteries for 80% self-consumption for the week of 1 August in 2015. With a high penetration of variable PV power, negative prices can be observed because of the excess power production. As shown in Fig. 11, our residential PV self-consumption model with batteries significantly reduces the risks related to negative prices.

4.2.2.4.2. Grid financing loss. Based on our PV self-consumption model, there is no PV production surplus injected into the grid. However, the grid should be sized to provide the maximum residual demand. As said, the residential peak demand in France occurs in the evening when the PV capacities do not produce the power.

French electricity tariffs comprise the energy cost (electricity), the grid cost for electricity distribution (user fee for the electrical public network known as TURPE[27]) and taxes[28]. TURPE represents 90% of the grid operator's revenue (Enedis). TURPE is calculated taking into account both fixed and variable costs which depend on the subscription type, the options taken, and the consumption profile. There are other segments in the retail electricity rates; different taxes and fees are added to these tariffs (CRE, 2016b). The diagram in Fig. 12 shows the price breakdown of the average residential electricity rates in France in 2015.

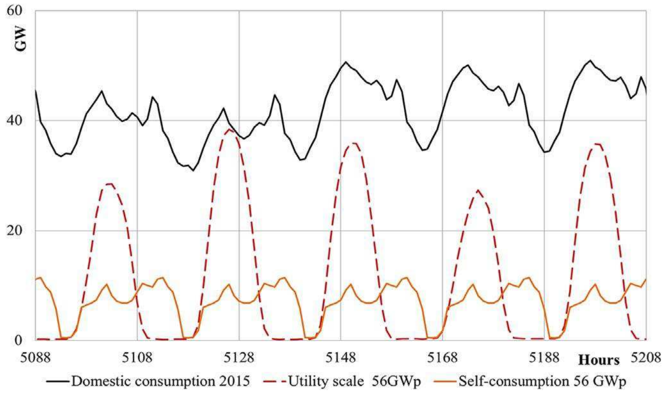

Fig. 11. PV production without batteries, PV production with batteries and demand for the week of 1 August (Author's elaboration based on RTE data).

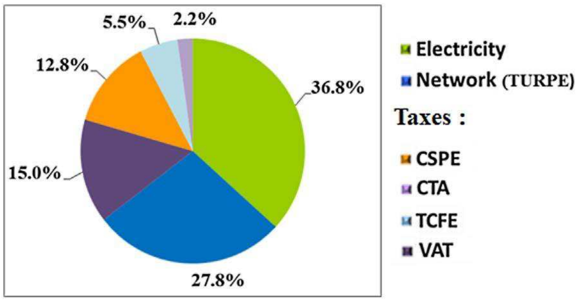

Fig. 12. Price breakdown of the average residential electricity rates in France (2016) (CRE, 2016b) (Author's elaboration).

Grid financing losses can be roughly estimated thanks to the structure of the electricity price. The use of the PV self-consumption model will bring about some changes in electricity tariffs because fewer customers will buy electricity from the grid with PV self-consumption.

About 28% of the current electricity tariffs in France are used for grid funding which amounts to around c\$5/kWh.[29] In this regard, if all the individual households in France installed PV systems with batteries, we could expect a loss of grid funding amounting to \$2.3 billion/year.[30] If the loss of network funding is equally distributed to end-users of electricity from the grid, the cost will be around c\$0.5/kWh.[31]

In this regard, the impact on the network cannot be ignored with regard to PV integration. Therefore, it is important to get the grid operators strategically engaged in the planning process of PV integration. Under the PV self-consumed model, preparing a fair scheme for grid

[26] The total profile costs / PV power sent to the grid (Scenario G) or self-consumed (Scenario S). As indicated, we considered a total of 46 TWh for the PV self-consumption model (a surplus is lost) and a total of 61 TWh for PV deployment without batteries.

[27] French abbreviation for *Tarif d'Utilisation des Réseaux Publics d'Electricité.*

[28] French electric utility tax (CSPE): French abbreviation for *Contribution au Service Public de l'Electricité*, Transmission Tariff Contribution (CTA): French abbreviation for *Taxe sur la Consommation Finale d'Electricité*, Tax on Final Electricity Consumption (TCFE): French abbreviation for *Taxe sur la Consommation Finale d'Electricité*, Value Added Tax (VAT).

[29] Electricity tariffs for households in 2015 were \$US 0.18/kWh in France.

[30] 46 billion kWh x c\$5/kWh.

[31] \$2.3 billion/(476–46 TWh), we considered the consistent demand of electricity ($\overline{E}_{total\,2015} = \overline{E}_{total\,2030}$).

cost recovery is necessary to justify the development of this model (IEA, 2014a, 2014b; IEA-RETD, 2014). The reform of electricity tariffs can be taken into account: for example, the rise in the fixed tariffs to finance the grid or the implementation of a floating time-based pricing to adjust to the real use of the grid.

5. Conclusion and policy implications

This study has shown that PV self-consumption with batteries could become profitable for individual investors in France before 2030. The demand in the residential sector would thus be natural in the near future in France. It is also possible to advance the time frame by improving the economic competitiveness of PV (e.g. non-module sector) driven by policy actions (e.g. standardisation).

However, the possible expansion of PV integration through a self-consumption model raises new issues for the electricity systems. Our model has shown that the large penetration of PV power induces a significant reduction in the residual load supplied by conventional power plants. This transition can reduce the profitability of existing power plants and possibly lead to the sub-optimisation of electricity systems.

We also found there was a greater impact on nuclear power plants under the scenario without batteries than with residential PV self-consumption. Our residential PV self-consumption model with batteries makes it possible to obtain higher levels of PV penetration before the overproduction occurs. The transition to PV self-consumption thus provides many opportunities for PV development with advantages. In addition, it is important to stress the fact that the speed of PV integration is a key factor since rapid integration is more costly than the progressive option. PV integration needs to be progressive based on gradual changes in the mix led by the systemic energy system plan. In this regard, energy policies can first focus on targeted sectors or niche markets to progressively start installing PV for self-consumption. The early encouragement of PV self-consumption can be intentionally planned to secure the constant growth model of PV installations. Afterwards, the speed of PV installation can be managed strategically to obtain an optimal mix of the energy systems in the long-term perspective.

The development of self-consumption must be associated with grid financing reform. For example, a time-based grid-usage pricing system can provide economic incentives to develop the distribution of a storage solution or promote demand management.

In conclusion, from a policy-maker perspective, it is thus extremely important to have a regular and progressive policy when transitioning to PV self-consumption in the future with the objective to allow enough time for the relevant stakeholders to adapt to the new market situation and to reduce the negative impact on the electricity mix by adapting to the age of the production capacity in use. How policymakers prepare for this change with a proper institutional framework supported by long-term vision will affect the success of PV integration. The future PV policy should be decided on the basis of a systemic perspective taking into account the costs for the whole energy sector.

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