Photovoltaic self-consumption regulation in Spain: Profitability analysis and alternative regulation schemes

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\textbf{A B S T R A C T}

Having achieved grid parity, photovoltaic (PV) self-consumption will play a key role in the transition to a low-carbon energy system. Spain, whilst among the EU countries with highest solar irradiation, has recently passed one of the most restrictive self-consumption regulations. We study the implications of this regulation in comparison with alternatives (net metering, net billing) on the profitability (internal rate of return) of potential residential, commercial and industrial investors, as well as the impact of PV self-consumption on government revenues and the electricity system. We find that this regulation hinders the diffusion of PV self-consumption applications by making them economically infeasible. It also creates inefficient disincentives for demand-side adjustment and by fostering disconnection from the grid. Under the current conditions, the direct economic impact of PV self-consumption on both aggregate government and electricity system revenues is positive for investments in the residential segment, negligible for those of the commercial segment and negative for those of the industrial segment. In order to raise compliance with the relevant European Commission guidelines and to promote the diffusion of PV systems at minimum cost to the electricity system, a dynamic net billing scheme is recommended.

1. Introduction

The cost decline experienced by photovoltaic (PV) technology during the last decades (IEA, IEA, International Energy Agency, 2015a) has allowed it to reach grid parity in many countries (EPIA, 2011, 2013; REN21, 2015), with grid parity referring to the point at which the cost of generating PV electricity equals the cost of buying it from the grid. This thus suggests that PV technology is set to play an increasingly relevant role in the process of decarbonizing the energy system (IEA, IEA, International Energy Agency, 2015b; WBGU, 2011). Spain, whilst being among those European countries with the highest levels of solar irradiation (Huld et al., 2012; Šturi et al., 2007) has recently passed one of the most restrictive self-consumption regulations (IEA, 2016a). As a result, studying the impact of self-consumption regulation on the profitability of PV investors under the current economic and regulatory conditions is of central interest.

This paper contributes to filling the research gap identified by the European Commission regarding the effect of different regulation schemes on the financial viability of self-consumption systems on residential prosumers (EC, 2015: 11). We expand the analysis to commercial and industrial segments, considering also the economic and behavioural impact of the backup charge (i.e. a charge levied on grid-connected PV systems) and the implications for cases when the investment is externally financed. We also quantify the direct economic impact of self-consumption on both government and electricity system revenues with reference to the guidelines of the International Energy Agency (2016a and 2016b).

Whilst most of the studies look at PV competitiveness and grid parity from the point of view of the levelized cost of electricity (LCOE) (such as the Eclareon Grid Parity Monitor reports; EPIA, 2011; and Dufo-López and Bernal-Agustín, 2015), we assess the profitability of PV installations in terms of their internal rate of return (IRR). This
allows us not only to evaluate whether PV systems are economically feasible, but also to quantify the specific profitability levels under both the current and alternative regulatory regimes. By estimating the IRR we can compare the impact of different regulations on PV profitability as well as the profitability across market segments. This enables us to compare PV investment with other kind of investment, regardless of the investment amount (IRR being a relative, as opposed to an absolute indicator, such as net present value) (Chiaroni et al., 2014; Spertino et al., 2013), and without needing to make arbitrary assumptions about the discount rate.

Section 2 summarizes the main features of the Spanish regulation, defines the market segments and the alternative regulation schemes analysed, and also briefly discusses the previous literature on the issue. Section 3 reviews the IRR methodology and Section 4 describes the data used for its estimation. Section 5 presents and discusses the results for both the current regulation and alternative regulation schemes, and reports on the sensitivity analysis for the most relevant parameters. Section 6 concludes by describing the policy implications derived from the analysis.

2. Background and literature review

2.1. Main features of the current Spanish regulation

There are in principle three basic options for regulating PV producers that allow for self-use of the electricity generated. In a net metering scheme (NM), the producer of electricity is granted the right to use the equivalent amount of energy generated, but at any time also different from the time of generation. Restrictions may apply on whether use has to be within the same day, month or year for example. Where different rates apply for the electricity generated and exported to the grid (typically lower) and the electricity self-consumed (typically higher) at times outside the generation period, the scheme is referred to as “net billing” (NB). In contrast to the above, the regulation established under the Royal Decree (RD) 900/2015 in Spain employs neither a net metering (NM) nor a net billing (NB) scheme. Instead, it creates two types of self-consumers. Type 1 is limited to below 100 kW installed capacity, is legally considered to be a mere consumer, and no reward is granted for exporting any surplus electricity to the grid. Alternatively, self-consumer type 2 is legally treated as both a consumer and producer. Here, the self-producer is perceived as an entrepreneur and is legally considered to be just like any other type of producer, i.e. PV self-consumption is thus considered to be a form of economic production rather than a form of saving.

By failing to acknowledge a NM or NB scheme, the RD is incapable of dealing with the concept of residential households as prosumers. By transforming incentives (i.e. by raising costs and institutional barriers) the RD makes it less likely that residential users of PV systems will sell their surplus electricity to the grid. For commercial and industrial companies, however, the opportunity cost of having two differentiated legal personalities is negligible, as they are already engaged in economic activity. Consequently, it is likely that residential self-consumers become type 1 agents, simply exporting (not selling) their surplus electricity for free, whereas commercial and industrial segments will become type 2 agents being able to sell the surplus electricity under the same conditions as any other producer, i.e. at wholesale price and paying the grid-access charge for generators established in the RD 1544/2011, plus the generation tax established under Law 15/2012.

The RD 900/2015 also establishes a backup charge billed to all PV producers that are linked to the electricity grid. It is divided into two parts: a fixed part based on the installed capacity (€/kW) on the one hand, and a variable part based on the self-consumed electricity (€/kWh) on the other hand. The charge on installed capacity is only applicable in some cases when battery storage is used. However, as we do not consider electrochemical storage in our analysis, this capacity charge does not show up in our empirical calculations. Nonetheless, we still explain how to implement it in the section on methodology. The second part of the charge, the charge on the electricity self-consumed applies to both types of self-consumers, but there are exemptions for type 1 installations below 10 kW of installed capacity and for the installations located in extra-peninsular systems: islands (Balearic and Canary) and autonomous cities (Ceuta and Melilla).

Another relevant feature of the Spanish regulation is that a single installation is not allowed to supply electricity to several different end-consumers, thus preventing installations in multi-family buildings and hampering the diffusion of the technology in urban areas.1

PV penetration in Spain accounts for a modest electricity market share of ~3.1–3.2% (coming mainly from utility-scale installations), compared to the 7–8% of other European countries such as Italy, Greece and Germany (IEA, 2015a). However, the Spanish electricity system faces financial constraints derived from the accumulation of “tariff deficits” (revenues of the electricity system not covering its costs) during the last decade (Paz Espinosa, 2013). That is why the main purpose of the regulation has been to avoid further costs rather than promote the diffusion of PV.2 Due to this cost-containment principle, the Spanish regulation did not apply a net metering or a net billing scheme, as followed in other European countries, but sought to avoid any potential cost derived from further PV diffusion. The PV industry association (UNEF) has criticized this regulation arguing that it sets unnecessary administrative barriers and that it is discriminative against PV. Indeed, all the parliamentary political groups (except the one in the government) have compromised to repeal this RD and remove the backup charge (popularly known as “sun tax”), yet the government has ruled out that possibility again in early 2017. Since the passing of the RD the PV sector has been virtually paralyzed with 49 and 55 MW of new capacity installed in 2015 and 2016 respectively, mainly in pumping, irrigation and heating systems of the agricultural and livestock sectors (UNEF, 2016). Many of these systems are isolated, so the RD regulation we analyse here is not applicable and they compete with diesel generators rather than with electricity from the grid.

2.2. Regulation schemes and segments definition

Depending on the specific economic and engineering criteria involved, there are many different definitions of net metering (NM) and net billing (NB) schemes (Bernal-Agustín and Dufo-López, 2006; Dufo-López and Bernal-Agustín, 2015). For the sake of clarity, we will define these different regulation schemes simply as a function of the price at which the surplus electricity is sold to the grid, assuming a one-year rolling credit to compensate the seasonal effect:

- Net Metering (NM): both self-consumed electricity and surplus electricity are valued at the same price: retail price.3
- Net Billing (NB): surplus electricity is valued at a lower price than the price at which it is bought from the grid. The average annual wholesale price and the average of wholesale and retail price are highlighted in the results section.
- Solely Self-Consumption (SC): we refer to SC when the surplus electricity is not remunerated at all.

The NM scheme entails a passive subsidy to PV generators, since PV

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1 This prohibition has been removed by the Constitutional Court on May 25th, 2017.
2 As mentioned in the statement of intent of the RD 900/2015, its aim is to “ensure an ordered development of the activity, compatible with the need to guarantee the technical and economic sustainability of the electricity system as a whole”, such that “the PV installations contribute to covering the costs and services of the system in the same amount as any other consumer”.
3 Note that we refer to the variable part of the retail price, since the fixed part is paid regardless of how much electricity is consumed.
prosumers are paid a higher price for the electricity they sell to the grid than are other generators (MIT, 2015:111). In contrast, under a SC scheme the prosumers are financing the electricity system, as they are giving electricity to the system for free, which is later sold at retail price to other consumers. Finally, a NB scheme at wholesale price would roughly entail competitive equality with other producers, as prosumers sell the surplus electricity at pool price.

Finally, we define three representative market segments (the data used for each segment is summarized in Table 1 and explained in Section 4):

- The residential (R) segment (consumption band DC\(^5\): 2500–5000 kWh per year, electricity tariff 2.0\(^6\)) faces higher installation (€2.07 /Wp)\(^7\) and financing (6.71%) costs, and is able to self-consume a lower share of the total electricity generated (33%), but since retail electricity prices are higher (€0.24 /kWh), their potential savings derived from self-consumption are also higher. While they belong to the type 1 category, and their surplus electricity is exported to the grid for free, they are exempted from the backup charge.

- The commercial (C) segment (consumption band IB: 20–500 MWh per year, tariff 3.0) faces the same installation costs as the industrial (I) segment (€1.26 /Wp), and medium financing costs (4.88%). They are able to self-consume 41% of the electricity generated and their retail price is €0.16 /kWh. They belong to type 2, so they sell their surplus electricity at the wholesale price minus a grid access charge and generation tax, and they face a backup charge on the electricity self-consumed.

- The industrial (I) segment (consumption band IC: 20–500 MWh per year, tariff 3.1) differs from the commercial segment in that it has a lower financing cost (3.36%), a higher share of electricity self-consumed (75%), and a lower retail electricity price (€0.12 /kWh).

2.3. Previous studies on photovoltaic self-consumption

The Royal Decree 900/2015 was passed after more than three years of discussion and three drafts released during that time. Dufo-López and Bernal-Agustín (2015) is the most recent and comprehensive paper regarding the assessment of levelized cost of electricity (LCOE) for PV self-consumption in Spain. They assessed profitability by comparing the LCOE of a PV system under the regulations proposed in the first two drafts of the RD and two reports of the National Energy Commission, with the net cost of buying electricity from the grid. Although this paper does not study the current regulation, but its drafts, we reach consistent results in the sense that they conclude that PV would be profitable under the regulation first proposed in 2011, but not under the 2013 draft, where a backup charge (on self-consumed electricity) was considered for the first time. LCOE analyses are widely used for assessing the competitiveness of renewable energy technologies (by comparing the LCOE across various technologies, or with the retail electricity price in the case of self-consumption). While LCOE is useful for evaluating the per kWh cost of different technologies, it does not exactly quantify the profitability of investments under different conditions. This is why we here choose the internal rate of return for our analysis instead of the LCOE.

Colmenar-Santos et al. (2012) assessed the potential profitability of PV with respect to household self-sufficiency, and concluded that self-sufficiency was economically feasible at prices for exported electricity below the feed-in tariffs (FiTs) then available (FiTs for new installations in Spain were removed in 2012 through the “Renewables Moratorium” established in the Royal Decree-Law 1/2012). Talavera et al. (2014) carried out a case study on the profitability of the PV installed in the University of Jaén under the regulatory framework in 2013. They also found positive returns on investment, and a pay-back time of between 17 and 18 years. We will follow and develop the methodology used in these papers, as set forth in detail in Section 3. A more general overview of the evolution of PV in Spain can be found in Mir-Artigues (2013), del Rio and Mir-Artigues (2012) and Mir-Artigues et al. (2015) as well as in the annual reports of the Spanish PV Industry association (ASIF, 2009, 2011; UNEF, 2013a, 2013b, 2015).

For the case of Italy, Chiaroni et al. (2014) assessed the profitability of self-consumption PV systems by carrying out a survey of 750 companies with systems between 3 kW and 1 MW, using as profitability indicators the net present value (NPV) and the discounted payback time (DPBT). They conclude that PV for self-consumption is profitable, with DPBTs of 5–6 years for residential installations, 6–8 years for large systems (1 MW), and at least 12 years for smaller commercial-industrial installations. Orioli and Di Gangi (2015) estimated the LCOE and the payback time (PBT) for three case studies, in order to assess the impact of the policy changes (from FiTs to tax credits) in Italy on PV self-consumption applications. They highlight the relevance of the support scheme for the economic feasibility of self-consumption installations.

In the international context, net billing schemes or equivalent (i.e. surplus electricity remunerated below retail price, some variants of “power purchase agreement” or “feed-in tariff” also work that way) are the most common schemes in countries such as Australia, Chile, Denmark, Germany, Italy, Portugal, Sweden and Switzerland. Some countries provide more beneficial net metering schemes such as Belgium (for residential prosumers in some areas and tending towards more competitive systems), Brazil, Finland, Israel, Mexico, Netherlands, Ontario (Canada) and 41 US states (IEA, 2016a). Although “it is generally accepted that variable grid costs on the part of electricity bill that is saved thanks to self-consumption should not be paid [by the prosumer]” (IEA, 2016a:31), some countries are discussing the convenience of some type of backup or grid charges. In this context, Spain has passed the most restrictive regulation by establishing a choice for the producer of only between either a set of backup charge, grid-access charge and generation tax (mainly for commercial and industrial segments), or the impossibility to sell the surplus electricity at a positive price (for the residential segment). Finally, many reports by international organizations have been published highlighting the evolution and prospects of PV self-consumption, such as EPIA, (2011, 2013, 2015), Solar Power Europe, 2015 or REN21 (2015).

3. Methodology

The method for the calculation of the internal rate of return (IRR) is now defined, focusing on the implementation of the generation tax and the grid-access and backup charges. The method for estimating the impacts of PV self-consumption on government revenues and on the electricity system is outlined in Section 5.2.

The IRR is used in its standard definition, i.e. as the discount rate (\(d\)) at which the net present value (NPV) of the investment (i.e. of the revenues and expenditures it triggers) equals zero. Thus, the NPV, which is the present worth of the cash inflows during the lifetime of the investment (\(NPV = (PW I (FiT s N))\) minus the life cycle cost of the system from the user standpoint (\(LC C o s p\)) must equal zero (Noñuñez et al., 2002). The following methodology follows previous analyses carried out by Colmenar-Santos et al. (2012), and Talavera et al., (2010, 2014).
In this context, our main contribution to the development of the IRR methodology lies in our incorporation of the effect of charges and taxes. There are two types of taxes/charges: on the one hand those imposed on the electricity exported to the grid, i.e. a grid-access charge for generators (denoted by $\delta_e$ in Eq. (8)) and established by the RD 900/2015, and the capacity payments (CNMC, 2016:91). On the other hand there is also a charge imposed on self-consumption ($\delta_c$; Law 15/2012). On the other hand, these revenues might be translated into savings when the amount received for the surplus electricity exported to the grid. These two categories correspond with the two addends in Eq. (8), and the fixed backup represents an additional cost (Eq. (6)).

Costs therefore include the initial investment ($PW_{VIN}$, Eq. (3)) in which we need to take into account the financing conditions (share $\alpha$ is externally financed at interest rate $i$ given the maturity of the loan $N$); the operation and maintenance costs ($PW_{OM}$, Eq. (5)), and the fixed part of the backup charge ($\delta_e$, Eq. (6)):

$$LCC_{usp} = PW[PW_{VIN}] + PW[PW_{OM}] + PW[\delta_e]$$

$$PW[PW_{VIN}] = (1-\alpha)\times PW_{VIN} + PV_{VIN} \times \alpha \times \frac{(1+i)^N}{(1+i)^N-1} + \frac{1-q^N}{1-q}$$

$$q = \frac{1}{1+d}$$

$$PW[PW_{OM}] = PV_{OM} \times \frac{K_{PV} \times (1-K_{PV})}{1-K_{PV}}$$

$$PW[\delta_e] = \delta_c \times \frac{K_{\delta_c} \times (1-K_{\delta_c})}{1-K_{\delta_c}}$$

$K_{PV}$ and $K_{\delta}$ are the discount factors of the O&M costs and of the fixed backup charge respectively, whereby the former depend on the respective escalation rates ($\delta_c$ and $\delta_e$); $d$ is the discount rate resulting from the IRR calculation. Thus:

$$K_{PV} = \frac{(1+\epsilon_{PV,om})^{1+d}}{1+d}$$

$$K_{\delta_c} = \frac{(1+\epsilon_{\delta_c})}{1+d}$$

We will focus now on the present value of the cash inflows ($PW[CIF(N)]$; Eq. (8)). The electricity generated by a self-consumption PV system ($EPV_{PV}$) can be either self-consumed ($\beta_{EPV}$), or exported to the grid (($1 - \beta_{EPV}$), with $\beta$ thus representing the share of electricity self-consumed. The profits from a self-consumption PV installation originate from the savings derived from self-consumption plus the revenues received for the surplus electricity exported to grid. These two categories correspond with the two addends in Eq. (8).

$$PW[CIF(N)] = \beta_{EPV} \times (ps - \delta_e) \times A_t + (1-\beta_{EPV}) \times [pg - \gamma \times (1-\delta_e)] \times A_t$$

The electricity self-generated and self-consumed is valued at the price that would be paid if that electricity were bought from the grid, i.e. the variable part of the retail price ($ps$), minus the variable part of the backup charge imposed on the electricity self-consumed ($\delta_c$). The price of surplus electricity exported to the grid ($pg$) can range from 0 (in the sole self-consumption scheme) to the retail price (in the net metering scheme), minus the grid-access charge for generators ($\gamma$). The effect of the generation tax ($\lambda$) must also be subtracted. Note that even these revenues might be translated into savings when the amount received for the exported electricity is directly discounted from the electricity bill. While this is not the case with the current regulation analysed here, it would be the case under a net metering or net billing scheme.

Finally, $A_t$ and $A_t$ are the discount factors for electricity self-consumed and electricity exported to the grid, respectively. They depend on the lifetime of the system ($N$), the depreciation rate at which the system loses efficiency ($d_g$) and the escalation rate of electricity prices ($\epsilon_{\delta_e}$). The latter is for both the price of saved electricity ($ps$) and the price of exported electricity ($pg$). Here, we consider the escalation rate of electricity prices after charges. By doing this, we assume that the charge increases at the same rate as electricity prices. As we assume
the escalation rate of electricity prices (p) to be the same for self-consumed and exported electricity (i.e. $e_p = e_p = e_p$). $A_y$ equals $A_y$.

Thus:

$$A_y = A_y = \frac{K_{p1} - K_{p1}}{1 - K_{p1}} ; \quad K_p = \frac{(1 + e_p - e_p - (1 + e_p))}{1 + e_p}$$

(9)

This methodology has two limitations. On the one hand, we do not consider hourly price discrimination, but only the annual average wholesale price. Provided that the price is usually higher at noon when most of the electricity is exported, it is likely that the real price paid to PV generators is higher than the wholesale yearly average. On the other hand, we ignore the potential decrease in peak prices caused by higher PV penetration. These two effects oppose each other, so by ignoring both we are implicitly assuming that they offset each other.

Table 1 provides an overview of the above variables and parameters, together with data sources and values. Further explanatory details are now given below in Section 4.

4. Data

The main factors determining the profitability of PV installations are solar irradiation intensity, share of electricity self-consumed, installation costs, financing costs and electricity prices. This section reviews the data used and the main assumptions considered in our calculations, along with their justification and sources.

4.1. Solar irradiation

PV GIS provides public information regarding solar irradiation and its corresponding PV generation potential based on Huld et al. (2012) and Šuri et al. (2007). We assume the PV yield ($E_{PV}$, Eq. (8)) of optimally mounted PV panels under average conditions in Spain (1328 kWh/1/kWp). For the “best case” calculations we assume the 90th percentile of irradiation (i.e. 10% of the values will be above this level) in Spanish urban areas: 1475 kWh/1/kWp.

4.2. Share of self-consumed electricity

One of the most critical parameters used in assessing the profitability of PV systems is the percentage of the total electricity generated by the system which is self-consumed ($\beta$, Eq. (8)). This value depends on the load profile of the prosumer as well as on the capacity of the system relative to total consumption. Since these characteristics vary across installations, we carry out a sensitivity analysis in Section 5.3. For the calculation of the main result we use the following assumptions:

- For residential (R) and commercial (C) segments, we use the average self-consumption values for Spain provided by the PV parity project, based on standardized load profiles for these segments: 33% and 41% respectively (Letterer and Auer, 2013a, 2013b)
- For the industrial (I) segment we assume that 75% of the generated electricity is self-consumed, as indicated by EPIA (2011).

4.3. Costs: installation and financing

Installation costs ($PW[PV_{in}]$, see Eq. (3)) refer to the total system price (modules, balance of systems and taxes). The values used in our study were reported in a private communication by the Spanish PV industry association (UNEF) and are consistent with those reported in the most recent IEA national report available (IEA, 2015c, table 8). We reduce those values by 10% to account for the expected short term cost decline reaching €2.07 /Wp for the R segment and €1.26 /Wp for C and I segments. This spread is likely to be caused by both the economies of scale for larger systems and the fact that the VAT (21%) is deductible for companies and therefore does not entail a cost.

The annual O&M costs account for 1% of the installation cost (Talavera et al., 2010, 2016) at an annual 2% escalation rate according to the long term ECB inflation target.

For financing costs (Eq. (3)) we evaluate two cases: own capital investment; and 80% externally financed for ten years at market interest rates (average of the last 10 years). These represent the typical financing conditions accepted by PV investors, according to UNEF (private communication). We assume the interest rates to be 6.7% for the residential segment, 4.9% for the commercial segment and 3.4% for the industrial segment. These values correspond to the 10-year average annualized agreed rate (AAR) for house purchase loans for the residential segment, and for small (≤ 1 M€) and large loans (> 1 M€) for the commercial and industrial segments respectively for Spain, provided by the European Central Bank.

4.4. Revenues and savings: electricity prices

Electricity prices are the main factor affected by the regulation. For a self-consumption installation there are two relevant prices: the variable part of the retail price at which the electricity is bought from the grid (ps), and the price at which the surplus electricity is sold to the electricity system (pg). Thus, profitability is determined by the value of the self-consumed electricity (implying a saving), and the price of the surplus electricity exported to the grid (representing a source of revenue8).

The regulation affects prices in two ways: on the one hand, the backup charge (δ) reduces the savings derived from self-consumption (which would otherwise be equivalent to the variable part of the retail price). On the other hand, regulation can establish the net price at which surplus electricity is sold to the grid (pg), as it specifies the grid-access charge (γ) and generation tax (λ), both of which are charged based on the gross price of the surplus electricity exported to the grid.

Revenues are only realised by C and I segments, since the R segment is not rewarded for the surplus electricity exported to the grid. For C and I segments, the revenues are equivalent to the amount of electricity exported to the grid multiplied by the wholesale electricity price (€0.042 /kWh) minus the grid access charge (€0.5/MWh) and the electricity tax (7%).

Savings depend on the retail electricity prices, which are the sum of the fixed part of electricity costs, the variable part and the value added tax (VAT). Since the fixed part of the electricity price is paid by the consumer regardless of the amount of electricity consumed, the potential savings derived from self-consumption come from the variable part of the price of the electricity consumed, plus the VAT for residential prosumers (for C and I prosumers, VAT is not a cost since it is always paid by the final consumer, so it does not entail a potential saving either). The backup charge on the electricity self-consumed entails a reduction of the potential savings. The net potential savings of PV self-consumption for different segments are depicted in Fig. 1 by the white bars.

The price per kWh largely depends on the annual consumption of the user. Due to the distribution of fixed charges to finance the costs of the electricity grid, the higher the consumption, the lower the final price per kWh. The most representative consumption bands are DC, IB and IC (R, C and I segments respectively), and a comprehensive analysis is carried out in section 5.3.3 in order to show how the different consumption levels and the different electricity tariffs in Spain affect our results.

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8This revenue would also represent a saving in the case of net billing or net metering schemes, where the value of the surplus electricity exported to the grid is directly deducted from the electricity bill.
with the backup exemption. The main problem for this segment is the impossibility of selling the surplus electricity to the grid, which is a large share of the total electricity generated (67%).

5.1.2. Alternative regulation schemes

We have defined the different regulation schemes as a function of the price at which the surplus electricity is exported to the grid, i.e., from a price of zero (in the case of solely self-consumption, SC) up to the retail price itself (in the case of net metering, NM), and net billing (NB) with any other price possible between these two. In contrast to the current Spanish regulation, NB and NM schemes recognize the concept of prosumer, through which the revenues raised by selling electricity are realised as savings in the electricity bill. This reduces transaction costs for prosumers and allows them to realise profits through savings instead of income, which is also more beneficial for investors from a fiscal perspective.10

The maximum price at which each segment can sell the electricity to the grid is equal to the potential savings of self-consumption, which is determined by the variable part of the retail electricity price. This would in fact be the case for the NM scheme in the absence of any additional charge. The backup charge has two effects: on the one hand it lowers profitability by diminishing the potential savings from self-consumption (see Fig. 1), and on the other hand it decreases the maximum price at which electricity can be sold to the grid in the case of an NM scheme. Finally, the backup charge also has a behavioural impact, since by reducing the difference between potential savings from self-consumption and the revenue gained by exporting the electricity to the grid (assuming it is remunerated), it reduces the economic incentives for self-consumption and demand-side adjustment.

External financing of the investment entails a cost when the IRR is lower than the interest rate. In contrast, leveraging the investment is profitable when the return is higher than the interest paid for external capital. As R faces high interest rates, financing is always a cost. However, the opposite is true for the C segment since it can take advantage of leverage to boost profitability when the latter is higher than the market interest rate (4.9%).

The dots in the R segment in Fig. 2 represent the situation under the current regulation (solely self-consumption), without backup charge for installations below 10 kW capacity and with backup charge for installations between 10–100 kW.11 As we have already mentioned, none of them is profitable. PV investment returns for R prosumers would be between 3% and 6% in two cases: under an NB scheme at the

5. Results and discussion

The impact of the current regulation and alternative regulation schemes on the profitability of PV self-consumption applications for the aforementioned representative segments can now be assessed. Further, we assess the direct impact of PV self-consumption on revenues of the government and on aggregate revenues within the electricity system following the guidelines of the IEA (2016a, 2016b).

5.1. Profitability for PV prosumers

5.1.1. Profitability under the current regulation

For the three representative segments—residential (R), commercial (C) and industrial (I)—we estimate the profitability under the current regulation, for both average irradiation conditions and “best case” (90th percentile of Spanish urban irradiation). In addition, we consider four different configurations in order to assess the impact of the backup charge and financing costs: we calculate the internal rate of return (IRR) with and without backup charge; and own capital investment vs. 80% externally financed at market interest rates for ten years.

The results reported in Table 2 show that even under our optimistic assumptions (panels mounted at optimal tilt and subtracting 10% of current installation costs), both R and I segments face negative or negligible returns on investment under average conditions. Only the C segment is able to gain positive returns, but these are in all cases below negligible returns on investment under average conditions. Only the C segment, the returns are negative even in the best conditions and in average conditions if the backup charge were not applicable. For the R segment, the returns are negative even in the best conditions and

Table 2

| Internal Rate of Return (%) | Type 1 Residential | Type 2 Commercial | Type 2 Industrial |
|-----------------------------|--------------------|-------------------|-------------------|
| Conditions (kWh/kWp)        | Segments           | Configurations    |                   |
|                             |                    | Backup | No Backup | Backup | No Backup | Backup | No Backup |
| Average (1328)              | Own Capital        | –6.12  | –2.53     | 2.11   | 3.59      | 0.94   | 3.30      |
|                             | Externally financed| –10.06 | –5.77     | 0.67   | 2.61      | –0.21  | 2.95      |
| Best (1475)                 | Own Capital        | –5.02  | –1.51     | 3.20   | 4.73      | 1.51   | 3.91      |
|                             | Externally financed| –8.74  | –4.54     | 2.10   | 4.16      | 0.55   | 3.79      |

* Indicate the settings of the current Spanish regulatory framework.

The maximum price at which each segment can sell the electricity to the grid is equal to the potential savings of self-consumption, which is determined by the variable part of the retail electricity price. This would in fact be the case for the NM scheme in the absence of any additional charge. The backup charge has two effects: on the one hand it lowers profitability by diminishing the potential savings from self-consumption (see Fig. 1), and on the other hand it decreases the maximum price at which electricity can be sold to the grid in the case of an NM scheme. Finally, the backup charge also has a behavioural impact, since by reducing the difference between potential savings from self-consumption and the revenue gained by exporting the electricity to the grid (assuming it is remunerated), it reduces the economic incentives for self-consumption and demand-side adjustment.

External financing of the investment entails a cost when the IRR is lower than the interest rate. In contrast, leveraging the investment is profitable when the return is higher than the interest paid for external capital. As R faces high interest rates, financing is always a cost. However, the opposite is true for the C segment since it can take advantage of leverage to boost profitability when the latter is higher than the market interest rate (4.9%).

The dots in the R segment in Fig. 2 represent the situation under the current regulation (solely self-consumption), without backup charge for installations below 10 kW capacity and with backup charge for installations between 10–100 kW.11 As we have already mentioned, none of them is profitable. PV investment returns for R prosumers would be between 3% and 6% in two cases: under an NB scheme at the

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10 The same profitability level will be effectively lower if it is realised as income rather than as saving, since income, unlike saving, is subject to direct taxation.

11 Although the backup charge corresponding to installations above 10kW installed capacity would be the one corresponding to the tariff 2.1, we apply the charge corresponding to the tariff 2.0—which is slightly lower than the one corresponding to the tariff 2.1—to see how the situation would be for the residential segment (< 10kW) should the backup charge exemption come to an end.
average of wholesale and retail price without backup charge, and under an NM scheme with the current backup charge.

The C segment could gain between 2–4% profitability with both NB at wholesale price without backup charge and NB at average wholesale-retail price with backup charge; and between 5–6% with both NB at average wholesale-retail without backup charge and NM with backup charge.

The I segment has the lowest profitability potential of the three segments due to the low electricity prices relevant for this segment, reaching maximum profitability of 4.6% in the case of a net metering scheme without backup charge. It is likewise the segment which is least sensitive to the price at which the surplus electricity is exported to the grid, due to its high share of self-consumption with respect to the total electricity generated. Therefore, reducing the price of the surplus electricity exported to the grid from retail to wholesale only reduces I segment profitability by 1.6 percentage points (to 3%).

For the I segment we can observe that profitability in the case of self-consumption without backup charge (upper dots in Fig. 2) is slightly higher than under the current regulation (‘soft costs’ and direct taxation on income are not considered). That means that it is more profitable for this segment to disconnect the system from the grid, and to waste the surplus electricity, than to exchange energy flows with the grid.
grid and pay the backup charge.

Removing the prohibition of sharing one installation among several different end-consumers could improve profitability in two ways: on the one hand pooling investment from different individuals could remove the need for external financing, increasing profitability when the internal rate of return is lower than the interest rate (Fig. 2). On the other hand, combining different load profiles could increase the share of self-consumed electricity, providing potential gains, particularly for the R segment, as shown in the sensitivity analysis (Fig. 7. A).

In the context of a transition to a more widely dispersed energy system, where non-dispatchable energy sources are likely to gain greater prominence, both the possibility of demand-side adjustment and thus of incentive design are likely to gain more relevance. That is why it is important to assess not only the economic effects of regulation, but also the incentives it creates. In this case, NB schemes seem more appropriate than NM, since they allow for price signals and thus are likely to encourage demand-side adjustment. In contrast, a charge on self-consumption works in the opposite direction by making demand-side adjustment less attractive. Finally, the combination of high backup charges and low or no remuneration of the surplus electricity (or high administrative barriers), encourages disconnection from the grid. This is an inefficient response since it tends to have a negative effect on both the prosumer and on the system as a whole.12

5.1.3. Dynamic adjustment

Although regulation needs to be stable and predictable in order to encourage PV investment and the long-term diffusion of PV technology, it also needs to be sufficiently dynamic so that frequent adjustment may be made according to the evolution of PV costs. Considering both the economic impacts and incentives of each kind of regulation, net billing without backup charge appears to be a more suitable scheme for the regulation of PV self-consumption in order to promote its diffusion at minimum cost to the electricity system. Since PV system prices are expected to keep declining, thus boosting the profitability of new PV self-consumption installations, the regulator will need to correspondingly decrease the effective price rewarded for the electricity exported to the grid in order to be able to adjust to the favourable downward evolution in the costs of new installations.

Fig. 3 shows the profitability as the system prices decrease to as low as only 50% of their current value, taking as a base case the own capital-no backup configuration. The government could set a benchmark profitability and reduce the price at which the surplus electricity is remunerated for new installations as PV system prices decrease. For instance, as can be seen in Fig. 3, if the benchmark profitability were 5%, the price of the surplus electricity exported to the grid for the C segment would now be €0.05, €0.04 when system prices drop by 10%, and even lower than the current wholesale electricity price once one moves beyond that point. For the R segment the same benchmark profitability would entail a price of €0.09/kWh exported to the grid, which would decrease for new installations at the same speed as the system prices until reaching wholesale electricity price when system prices drop by 30%.

Finally, the I segment is more sensitive to the system price than to the price of the surplus electricity exported to the grid, so its profitability will increase significantly as the system prices go down, even with low prices for the electricity exported to the grid.

5.1.4. Boundary conditions

Although the results described above are quite representative for the most relevant segments, they are still subject to variation depending on the electricity consumption of the individual prosumers and their respective tariffs. In this section we expand the analysis to cover the most relevant electricity consumption bands as defined by Eurostat and with respect to the electricity tariffs in the Spanish electricity market (CNMC, 2014, 2016).

Fig. 4 shows the results for the R (panel A), C and I (panel B) segments. The situation under the current regulation is shown in black/grey, whilst the results for net billing (square) and net metering (triangle) schemes are shown in purple and dotted markers. It is assumed that the investment is 80% externally financed at market interest rates since these are the typical financing conditions according to UNEF (private communication). We can see that under current circumstances none of the residential sub-segments can gain positive returns. There is a niche, however, for the I segment, with low electricity consumption and tariffs 3.0 or 3.1. Under a net metering scheme without backup, profitability could reach up to 15% for the R and I segments, and up to 10% for the C segment.

5.2. Impact of PV self-consumption on government and electricity system revenues

In this section, applying the guidelines of the International Energy Agency (IEA, 2016a, 2016b), we now assess the direct economic impacts of PV self-consumption on both government and electricity system revenues. The net impact on government revenues is the result of, on the one hand, the lower VAT and electricity tax derived from self-consumption, and, on the other hand, the additional VAT derived from the installation and operation and maintenance costs, and the electricity tax on the surplus electricity exported to the grid (only for C and I segments), over the lifetime of the system (25 years), discounted at a 5% discount rate. Fig. 5 shows that the net present value (€/kWp, at 5% discount rate) of the direct impact of PV self-consumption on government revenues is positive in the case of the R segment, due to the high installation costs (and therefore VAT), and negative for the case of C and I segments. Since the I segment is able to self-consume most of the electricity it generates, it has the largest negative impact on government revenues due to the associated reduction in VAT revenue. The removal of the electricity tax for PV generators would have only a relatively minor impact on government revenues.

We now assess the impact of PV self-consumption on the electricity system, which we define as the aggregation of the following actors: generators, suppliers, transmission and distribution system operators and electricity consumers, and excluding PV prosumers on the one hand and the government on the other. This broad definition, while not allowing us to assess the distributive effects of PV self-consumption across electricity system actors, is consistent with the IEA (2016a) definition and does allow us to quantify the net impact of PV self-consumption on the electricity system, defined across the actors stated above. We assess the direct impact of PV self-consumption in the three different market segments and under three different regulation schemes, i.e. conditions under current regulation, under net billing, and under net metering schemes without a backup charge.

The direct economic impacts of PV self-consumption on the electricity system are summarized in Table 3. The positive impacts comprise the value of the surplus electricity exported to the grid (i.e. the variable part of the retail electricity price; this factor is ignored by IEA (2016a)), the backup charge on the electricity self-consumed and the grid-access charge on the electricity exported to the grid. The negative impacts are the price paid by the system to the prosumer for the surplus electricity exported to the grid and the reduction in electricity consumption equivalent to the self-consumed electricity.

PV self-consumption has by definition a negative impact on the electricity system revenues, since it reduces the electricity bill of...
We find, however, that under the current conditions residential prosumers are financing the electricity system by exporting the surplus electricity to the system without any remuneration (Fig. 6). The impact of C prosumers is negligible, and only the I segment has a negative impact of 3.15 € cents per kWh generated by the PV system. The negative impacts on the aggregate revenues of the agents of the electricity system obviously increase as the regulation becomes more beneficial for the prosumer. It is worth noting, however, that due to the price difference between wholesale and (the variable part of the) retail electricity price, the net impact of residential self-consumption on aggregate revenues of the agents within the electricity system is positive in the case of a net billing scheme at wholesale price.

Fig. 3. Profitability as a function of the price of the electricity exported to the grid for Residential (R), Commercial (C) and Industrial (I) segments, as the PV system cost (€/kWp) decline by 10%, 30% and 50% respectively, relative to base case (own capital, no backup charge) values.
5.3. Sensitivity analysis: share of electricity self-consumed, installation costs and retail prices

We finally carry out a sensitivity analysis on the most relevant parameters: the share of electricity self-consumed with respect to the total electricity generated, the installation costs (system prices) and the retail prices (both current and expected escalation rate). We take as base case the situation under the current regulation (see Section 2.1) and investment 80% externally financed at market interest rates.

The sensitivity of profitability to the share of electricity self-consumed (panel A) depends on the difference between the variable part of the retail price (the savings of self-consumption, reduced by the backup charge), and the price of the surplus electricity exported to the grid (i.e. \((p_s - \delta_e) - p_g\)). The sensitivity is higher for the R segment because according to the current regulation the surplus electricity is exported for free (\(p_g = 0\)). The C and I segments’ profitability is characterized by lower sensitivity because of lower retail prices (see Fig. 7) and the fact that backup charges decrease potential savings (and therefore the difference between the price of the electricity saved and the electricity exported to the grid). Thus, if any charge is to be implemented, it would be more efficient, considering incentives, to charge it on the electricity exported, since it would result in a higher difference between the price of the electricity saved and the electricity exported, and consequently a higher economic incentive for self-consumption and demand-side adjustment.

Under the current regulatory framework (panel B), achieving 5% return on investment would require a drop in installation costs of around 25%, 30% and 55% for R, C and I segments respectively.

Finally, panel C shows how an increase in retail prices \((p_s)\) would affect profitability, and panel D shows the impact of different assumptions regarding the annual escalation rate of retail prices \((\varepsilon_{ps})\) during the lifetime of the system (25 years) on the internal rate of return for the three different segments. Obviously, the higher the retail prices or their escalation rates, the higher the profitability derived from the savings of the self-consumed electricity. To achieve 5% internal rate of return, retail electricity prices would need to be ~50% higher for the commercial and industrial segments, and more than double for the residential. The I segment is the most sensitive to the retail price due to the higher share of electricity self-consumed.

6. Conclusions and policy implications

Under the current Spanish regulation (RD 900/2015), commercial and industrial PV self-consumers (type 2) can sell the surplus electricity to the grid at wholesale price, paying the grid access charge and the generation tax on that price, and a backup charge on the electricity self-consumed. Residential PV self-consumers (type 1) have a backup charge exemption for installations below 10 kW but the surplus electricity exported to the grid is not remunerated. We find that this regulation is likely to hinder the diffusion of PV grid-connected systems for self-consumption in Spain, as it makes them economically infeasible for average users of the residential and industrial segments.
remuneration for surplus electricity, in combination with the backup consumption discourages demand-side adjustment. The absence of flows with the electricity system. In addition, the charge on self-to disconnect the PV system from the grid in order to avoid the backup incentives in that it makes it more pro-

let alone the costs of legal uncertainty and the other investment, this is unlikely to cover the opportunity costs of capital, While the commercial segment can gain up to 2.1% return on investment, this is unlikely to cover the opportunity costs of capital, let alone the costs of legal uncertainty and the other 'soft costs' omitted from our calculations.

For the residential segment, the impossibility of selling the surplus electricity to the grid, even with the backup charge exemption for systems below 10 kW installed capacity, makes the amortization of the investment impossible at current installation costs. This is true because the load profile of the average domestic prosumer significantly differs from the generation profile of the PV system, and because self-producers are forced to give away for free most of the electricity generated (on average some 67%). For commercial and industrial prosumers, the backup charge significantly harms the profitability of PV self-consumption installations, which would otherwise be in the range of between 2.6% and 3.6%. All segments, particularly the residential, can, however, increase profitability by increasing the share of electricity self-consumed out of the total generation above the averages assumed here (33%, 41% and 75% for the residential, commercial and industrial segments respectively).

To a certain extent the current regulation also creates inefficient incentives in that it makes it more profitable for the industrial segment to disconnect the PV system from the grid in order to avoid the backup charge and even to waste the surplus energy, than to exchange energy flows with the electricity system. In addition, the charge on self-consumption discourages demand-side adjustment. The absence of remuneration for surplus electricity, in combination with the backup charge, encourages disconnection from the grid, which results in overall inefficiency, as surplus electricity would be available at a production cost lower than potential consumers’ willingness to pay for it, but is not supplied to the market.

Under the current conditions the direct economic impact of PV self-consumption on government and electricity system revenues is positive for the case of investments in the residential segment, negligible for those in the commercial segment and negative for those in the industrial segment.

According to our analysis, in order to promote the diffusion of PV self-consumption applications at minimum cost for the electricity system, and in line with the European Commission best practice guidelines on renewable energy self-consumption (EC, 2015), we highlight the following principles for the regulation of PV self-consumption. While we have carried out the numerical calculations for the case of Spain, the following general conclusions apply broadly.

- As grid parity is achieved, net billing schemes are preferable to net metering, since net billing sends a price signal to prosumers to maximize the share of self-consumed electricity and encourage demand-side adjustment while mitigating the negative impacts of PV self-consumption on the electricity system and discouraging disconnection from the grid (since the surplus electricity is remunerated).
- Charges on self-consumed electricity should be avoided, since they reduce the aforementioned price signal and encourage disconnection from the grid. For these reasons, grid and backup costs should rather be imposed on the surplus electricity exported to the grid as PV penetration increases.
- The surplus electricity exported to the grid should be valued somewhere between the wholesale and the retail prices. This would provide positive profitability for all segments (residential, commercial, and industrial) at minimum cost to the system. Since such surplus electricity is then sold to other consumers at retail price, the difference between these two prices (i.e. between the remuneration paid for surplus electricity and the retail price received) would contribute to covering the costs of the electricity system.
- In order to match the declining cost trend in PV technology, the price of the surplus electricity for new installations needs to be periodically adjusted to account for lower installation costs. This not only helps reduce the potential for windfall profits, it also serves to provide for greater financial sustainability of the electricity system as PV penetration increases.

### Table 3
Economic impacts of PV self-consumption on aggregate revenues of actors within the Spanish electricity system.

| Positive impacts | Negative impacts |
|------------------|------------------|
| + Variable part of the retail electricity price for the surplus electricity exported to the grid | - Remuneration of the surplus electricity exported to the grid |
| + Backup charge on the electricity self-consumed | - Variable part of the retail electricity price for the electricity self-consumed |
| + Grid access charge on the surplus electricity exported to the grid | |

* Electricity system actors comprise generators, suppliers, TSO, DSO and electricity consumers. Source: own elaboration based on IEA (2016a).

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- Charges on self-consumed electricity should be avoided, since they reduce the aforementioned price signal and encourage disconnection from the grid. For these reasons, grid and backup costs should rather be imposed on the surplus electricity exported to the grid as PV penetration increases.
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- In order to match the declining cost trend in PV technology, the price of the surplus electricity for new installations needs to be periodically adjusted to account for lower installation costs. This not only helps reduce the potential for windfall profits, it also serves to provide for greater financial sustainability of the electricity system as PV penetration increases.
Finally, different end-consumers should be allowed to share a single installation. This could contribute to reducing financing costs and increasing the share of self-consumed electricity, increasing profitability and promoting the development of PV self-consumption applications in buildings and urban areas.

These principles are consistent with the European Commission guidelines and with the latest policy development in leading countries such as Italy, Germany and some federal estates of the US. The methodology presented in this paper is likely to be useful to regulators wishing to assess the impact of such regulations on potential investors and thus on the diffusion of the technology. Further research needs to focus on the implementation of batteries given their expected future cost reduction, on the evolution of wholesale electricity prices, and on developments in electricity system costs as PV penetration increases.

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