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The Photovoltaic Crisis and the Demand-side Generation in Spain

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CWPE 1311

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EPRG Working Paper 1307

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Abstract

The RES-E promotion policy in Spain gave priority to the photovoltaic (henceforth, PV) ground-mounted installations. For years, the coupling of customer-side generation coupled with excess energy exports was never specifically considered. However, some months ago this option was suggested as a way to recover the Spain's PV sector from the current moratorium on the RES-E policy. A decree draft on on-site generation was issued, its central point being the consideration of electricity exports as delayed consumption rights. But several barriers hinder its entry into force. Unfortunately, Spain could be losing an important opportunity for encouraging PV investments while retail grid parity is being reached. This working paper analyzes the different types of PV demand-side generation from the point of view of consumer-generators and evaluates the economic and technical features of the regulation proposed in Spain and to date still pending.

Keywords Distributed on-site generation, net metering, Spain

JEL Classification Q 42 Q48

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Publication March, 2013

www.eprg.group.cam.ac.uk

EPRG 1307

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1. Introduction

This working paper describes the history and prospects of Photovoltaic Demand-Side Generation (henceforth, PV-DSG) in Spain. The PV-DSG can generally be defined as the production of electricity by means of panels or arrays (the energy conversion units), which are placed near the consumption points (Alanne & Saari, 2006). Photovoltaic modules are normally mounted in the same building or within the area where the consumers of the generated electricity are living and/or working. These installations are usually owned by individuals (not by organized shareholders) but not necessarily managed by them. As it is known, normally part of this energy is directly consumed by the owner/s of the installation and part is sold to obtain an economic benefit that compensates for the electricity consumed from the grid. However, there also are other possibilities as explained below.

2. Spain's PV Policy 1996-2012

2.1. *A Short Overview*

The policy promoting renewable sources of electricity began in the early 80s. Undoubtedly worried about Spain's dependence on hydrocarbon imports, the Government passed Law 82/1980 for the Conservation of Energy that set down the support of renewables. This law established a guaranteed price (fixed by annual orders of the Ministry responsible for energy issues for all the installations, that is, new and already operatives) for the excess electricity fed into the grid for installations up to 5 MW. This price was accompanied by upfront investment subsidies. The impact of this law was very small because oil prices plummeted just three years later and RES-E support policies were abandoned.

Nothing more happened until 1994 when Royal Decree (henceforth, RD) 2366/1994 on electricity generated by hydro sources, cogeneration and renewable technologies was issued. These generators would receive a monthly payment based on plant capacity and a (small) price for kWh delivered.[1] Initial values of both prices were fixed in the article 14. They would be annually updated according to the average increase of the electricity prices. Although this remuneration scheme may be considered a FIT, subsidies up to 20% of the up-front costs were the main tool to support RES-E investments. There is no doubt that this policy was crucial to boost wind power generation, but it was of a minor importance for PV as the remuneration and investment subsidies were too low.

The turning point of RES-E support policy was the *Law of the Electricity Sector* enacted in 1997 (*Ley 54/1997*, LSE, 2008). With the aim of achieving the EU target of 12% of gross energy consumption from non-conventional sources in 2010, this law consolidated the Special Scheme (*Régimen Especial*) for electricity generation. This scheme encompassed renewable sources, cogeneration and power production from urban solid wastes (only for plants up to 50 MW). It also established preferential prices

[1] Distribution companies were obliged to buy the electricity produced by these special generators.

for the kWh fed-in,[2] but it made no reference to self-generation. Only article 9.1.a allowed self-consumption for the electricity producers, that is, permitted them to use part of the energy generated for on-site equipment demand. Because other forms of consumption netted from distributed on-site generation coupled with the sale of excess energy was not specifically envisaged, the RES-E support policy gave priority, from the beginning, to the PV ground-mounted grid-connected installations. Actually, no particular and specific legislation for PV-DSG was ever developed.

The Special Scheme plants would benefit from FITs and premiums. Details were developed a year later in RD 2818/1998, which established that RES-E generators could choose between two remuneration alternatives:

- A fixed premium on top of the average hourly wholesale market price.
- A fixed total price (fixed feed-in): €0.396/kWh for PV installations ≤5 kW and €0.216/kWh from 5 to <50 MW. Although FIT for small plants can be envisaged as designed to promote distributed self-generation, specific technical and administrative rules were never set up. Related to commercial plants, the support level was regarded as too low.

In both cases, the annual revision was based on technology and the expected electricity price for the following year. This uncertainty discouraged investments: during the 62 months in which this decree was in force, less than 7 MW were installed (while 150 MW were expected).

It is also important to take into account that small projects, each with its independent owner/s, were allowed to merge and obtain economies of scale (they shared the BoS [Balance of System] and O&M costs) and the highest FIT (being legally considered as separate plants). As a consequence, ground-mounted grid-connected plants, grouping several arrays side by side up to 5 kW, became the common PV facility (de la Hoz, 2010: 2559-2561; del Río and Mir-Artigues, 2012: 5559). These tiny plants merged into large ones were called *huertos solares* (literally “solar orchards”). This situation would not change for 10 years.

Several reasons explain because preferential prices were the instrument applied in Spain to support RES-E, and in particular PV, deployment instead of other options. Namely,

- In mid 90s, FITs were being progressively adopted elsewhere since they were regarded as a powerful instrument to kick-start the market, that is, to boost RES-E investments. Therefore, FITs provided an opportunity to link energy and industrial policy goals (for example, the creation of a domestic PV industry). Other alternatives, as the Non-Fossil Fuel Obligations in the U.K. (Pollitt, 2010: 16-19), failed.
- In the short-term, it was expected that PV support costs would not be high because of the low penetration level. Therefore, electricity consumers paying for the promotion policy would be unlikely to complain.

Policy makers therefore regarded the implementation and management costs of FITs scheme as easy and cheaper. See Figure 1, which shows its different phases from 1996 to 2012 and Figure 2, which shows the expansion, in logarithmic scale, of PV capacity.

In March 2004 RD 436/2004 was enacted. This new decree featured two novelties:

[2] The true economic meaning of FITs is to be preferential prices because they are guaranteed markup on some reference price (normally, the electricity market price). For this reason both expressions are interchangeably used throughout this paper. However, in these later years FITs have been strongly reduced and, in several cases, they are closer to retail prices.

- FITs were set up as a percentage of the average electricity price (AET): for PV installations ≤100 kW, the support level was set as equal to 575% of the AET for the first 25 years and 460% thereafter, encompassing therefore the whole lifetime of the plant. This system was considered more objective and reliable, but the level of AET for the next year was still being set annually through Government's decision. The second one strengthened the solar orchards arrangement.
- The capacity threshold to receive the maximum support level was increased from 5 kW to 100 kW.[3] This extension of the highest tariff gave rise to very big solar orchards formed by several plants of ≤100 kW each.

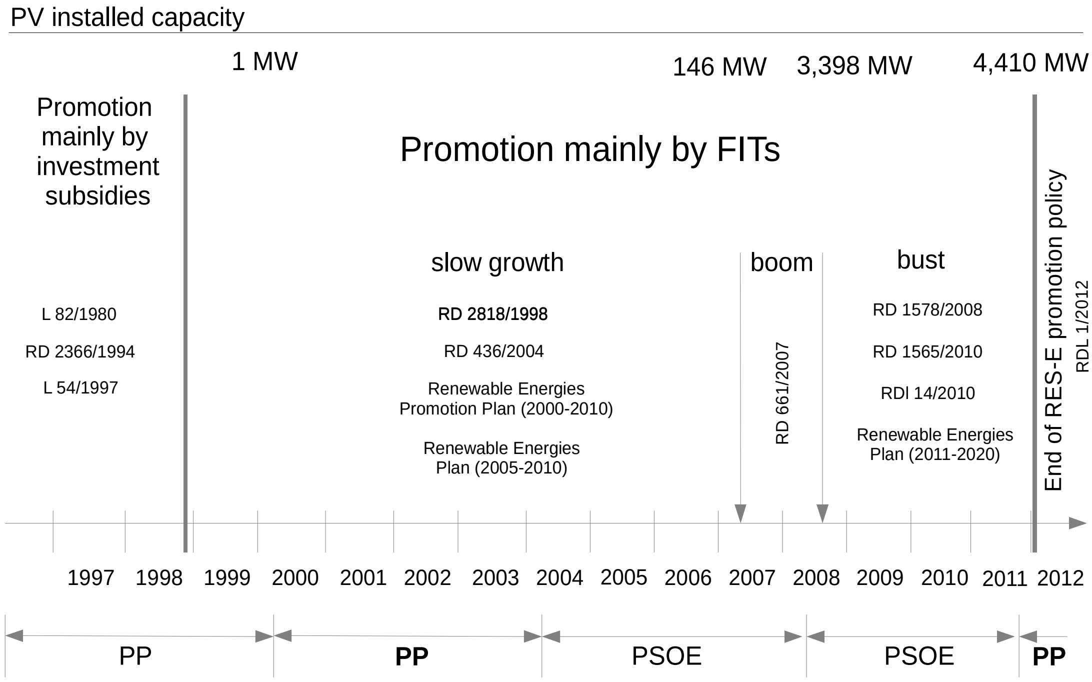

Figure 1. The different periods of the Spanish PV policy (1996-2012)

Note: PP (*Partido Popular*) conservative, PSOE (*Partido Socialista Obrero Español*) social democratic. Bold type means absolute majority in Parliament.
Source: Own elaboration

Three years later RD 661/2007 was passed. FITs did not change except for facilities from 100 kW to 10 MW, which were awarded with an outstanding increase (82%, from €0.2297 to €0.4175). From then onwards, PV plants below 10 MW would receive very similar and profitable tariffs. Nonetheless, the most important novelty of this decree was the uncommon stability and predictability given to PV investments: a set of FITs not affected by degression rates [4] (or any other mechanism regarding efficiency improvements or electricity bill impact) was established, which would be updated for operating plants according to inflation. Furthermore, FIT was guaranteed for the plant's lifetime.

Table 1 shows the tariff scheme established by RD 661/2007. Tariffs for operating plants would be updated every year according to CPI (ε_t). However, this value would be slightly reduced by 0.25 percentage points (h_t) until 31[th] December 2012 and

[3] The FIT dropped rapidly for plants beyond this size.
[4] Degression rate means that the initial tariff for new plants will decrease every year or another time extent (see below).

0.5 percentage points the following years, all sizes encompassed. As a result, the tariff for the year t would be given by the expression,

$$p_t = p_{t-1}\left(1+\varepsilon_t - \frac{h_t}{100}\right)$$

where p_t and p_{t-1} indicate respectively the tariffs in the years t and t-1.

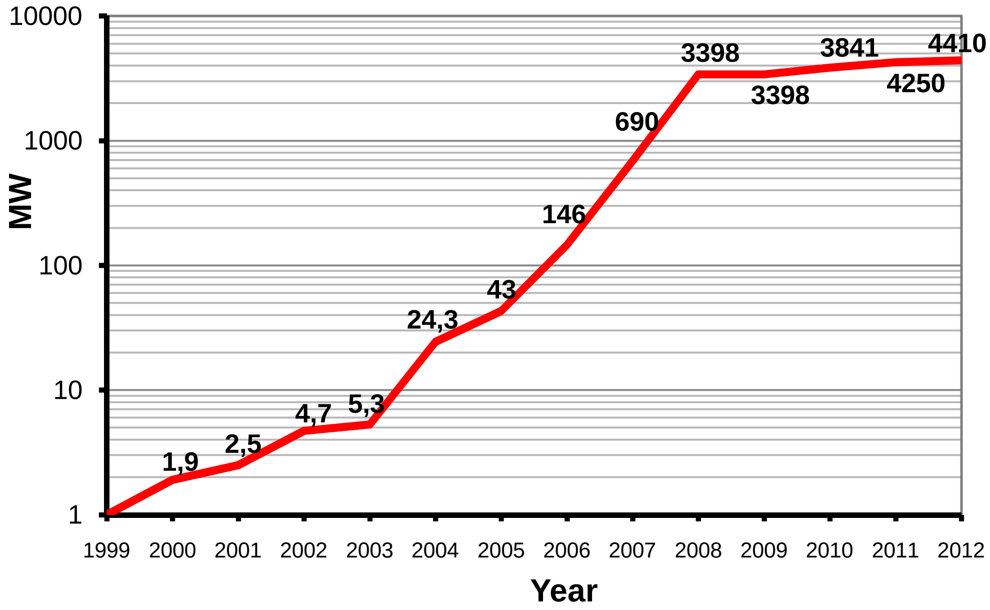

Figure 2. Accumulated PV capacity (logarithmic scale) and regulatory changes
Note: * From January to mid-December 2012. At this end of that period there were 59,238 PV plants.
Source: Own elaboration based on the latest official data (CNE)

Table 1. PV tariff scheme

Sizes	Duration	Tariffs (€/kWh)
≤ 100 kW	First 25 years	0.440381
	Following years	0.352305
> 100 kW and ≤ 10 MW	First 25 years	0.4175
	Following years	0.334
> 10 MW and ≤ 50 MW	First 25 years	0.229764
	Following years	0.183811

Therefore, tariffs established by RD 661/2007 can be divided in the five parts, as follows:

$$\begin{cases} p_t = p_0 & \text{for } t=1 \\ p_t = p_{t-1}\left(1+\varepsilon_t - \frac{0,25}{100}\right) & \text{for } t=2,\ 3,\ 4 \text{ and } 5 \\ p_t = p_{t-1}\left(1+\varepsilon_t - \frac{0,5}{100}\right) & \text{for } t=6,\ ...,\ 25 \\ p_t = p_{26} & \text{for } t=26 \\ p_t = p_{t-1}\left(1+\varepsilon_t - \frac{0,5}{100}\right) & \text{for } t=27...,\ T. \end{cases}$$

with, for example, p_0= €0.440381 per kWh and p_{26}=0.352305 per kWh for plants ≤100 kW.

PV capacity grew rapidly from June 2007 to September 2008, that is, the sixteen months in which the RD 661/2007 was in force: from 261 MW to 3,105 MW. Throughout this period a *monthly* average of 178 MW were installed, which represents a *monthly* compound growth rate of 16.73%. The reasons behind this boom are multiple.[5] Some are related to the design of FITs itself. Namely:

- Although tariffs were calculated in order to guarantee a real rate of return between 5%-9%, the number of full load hours was underestimated (for example, the spread of tracking systems was not considered) and, as a result, returns ran from 10% to 15%. But the level of the FIT price cannot be identified as the *exclusive* cause for the boom: the RD 661/2007 fixed the tariff of €cents 44.04 per kWh for installations below 100 kW, but this value had been slowly increasing from March 2004 when a tariff of €cents 41.44 per kWh entered in force. Therefore, the boom should have started in 2006 or even before, not in 2007.
- It was established that, when the capacity target of 371 MW was reached, economic conditions of the decree would be extended for a 12-month minimum interim period. At the end of this period, a new (and presumably reduced) FIT scheme would be set up. It should be pointed out that this capacity target was barely 50 MW above the one already installed when the RD 661/2007 entered into force. There is no doubt that the Ministry of Industry was worried about the high cost of PV generation. But the problem was that the length of the interim period was longer than the time needed to install a simple modular technology like solar PV. This was the Achilles Heel of the Spanish PV regulation.

The combination of fixed and updated preferential prices yielding high internal rates of return, coupled with an abrupt although distant end of the tariff framework, boosted a rush for the submission of proposals. Moreover, two external factors fuelled this race:

- The end of the housing market boom, which had produced an enormous cash surplus looking for profitable investment allocations.
- Easy access to credit in these years. Banks and savings banks did not hesitate in finance the entire PV investment (usually by means of project finance conditions). Not only professional investors, such as investment and pension funds, went for it, but middle-class professionals, SME owners, farmers, etc. Surprisingly enough, utilities were barely interested.

The PV boom obviously triggered a large increase in the costs of the RES-E policy. As Table 2 shows, from 2008 onwards the percentage of renewable support costs represented by the tariffs paid to PV generators (an average of 48.3%) is much larger than the percentage of green electricity generated (an average of10.2%) and with that of generation mix (an average of 2.2%).

In September 2008, a new decree (RD 1578/2008) aiming at cost-containment was enacted. First, a centralized administrative procedure for registering the PV capacity, which was also capped to 500 MW/year, was established; second, an allocation system involving four calls a year on a first come, first served basis was set up; and, finally, FITs were reduced and attached to a degression mechanism (which implied an inter-annual reduction of 10% for new installations). These measures, coupled with bureaucratic delays and the shortening of financial resources due to Spain's acute economic crisis, caused the stagnation of the PV sector. Actually, in 2009

[5] A complete analysis could be found in del Río and Mir-Artigues (2012) and Mir (2012).

the added PV capacity was zero. But despite the priority this decree gave to small-to-medium roofs plants, no category was created for on-site generation plants.

Table 2. Evolution of PV tariffs and generation

Year	Total tariffs paid to PV generation (k€)	Average tariff cost of MWH PV(euro)	% PV tariffs with respect to all renewable* tariffs	% MWH PV of the renewable* generation mix	% MWH PV of global generation mix
2004	6,146	341.44	0.93%	0.08%	0.01%
2005	13,995	341.34	1.75%	0.15%	0.01%
2006	39,887	372.78	3.53%	0.35%	0.04%
2007	194,162	392.25	13.44%	1.36%	0.16%
2008	990,830	388.71	40.88%	6.09%	0.96%
2009	2,634,236	424.60	55.90%	11.72%	2.45%
2010	2,653,720	414.25	49.66%	10.65%	2.46%
2011	2,402,986	390.22	47.79%	10.46%	2.41% (2.91%)º
2012†	2,567,302	392.31	47.28%	11.98%	2.58% (2.89%)º

* Renewable sources: Hydroelectric power, wind power, biomass power, CSP and PV.
† January to mid-December 2012
º % eligible and (non-eligible added)PV MWH
Source: Own elaboration based on the latest official data (CNE)

With some significant alterations, this royal decree was in force for three years. One important amendment was RD 1565/2010 which included a non-scheduled FITs reduction (the 10% regression rate had been overtaken by the rate of decrease of PV prices). In addition RDL[6] 14/2010 included a strong reduction in the eligible full load hours to be paid at FITs (the remaining energy was to be paid at wholesale market prices).[7] It goes without saying that the Spanish sector considered these measures to be retroactive.[8]

Unsurprisingly, cost-containment measures were more effective in controlling the financial cost of the post-boom capacity than that of the capacity installed in 2007-2008. Unfortunately, from its very beginning this problem became immediately related to the tariff deficit issue,[9] which finally compelled the new Government, formed after

[6] A royal decree-law (RDL) is also issued by the Government but requires parliamentary ratification.
[7] It was estimated that this restriction reduced plants turnover up to 30% (ASIF, 2011: 29-30).
[8] Retroactivity is a complex legal issue. In principle, once a generator locks into a given tariff scheme, this cannot be *backwardly* and *arbitrarily* readjusted. However, there are two very different situations: A regulatory change which implies a new estimation of the revenues previously gained, probably reducing them, and urging the return of surpluses, what is clearly illegal (it is retroactive); and the case in which rates are changed but only with forward effects and provided that the profitability of investments remains unchanged. Although this second type of regulatory amendment has been accepted by the Spanish Constitutional Tribunal as well as the Supreme Court, the Spanish PV sector considered the condition of unaffected profitability was broken. Despite the final decision of courts, there is no doubt that this kind of legal modifications has strong negative effects on investor confidence (see del Río and Mir-Artigues, 2012).
[9] The tariff deficit started at the end of 90s when the Government, interested in maintaining retail electricity prices at a very affordable level, decided to delay to the future part of the electricity system expenditures. Leaving details aside, authorities reserved the decision on access charges and let financial electricity markets determine energy prices. Access charges fund T&D activities, the RES-E policy, the budget of the regulation agency, the debt service of the tariff deficit, etc. As regards the energy consumed, ratepayers below 10 kW of demand load,

the elections held on November 20th 2011, to stop all RES-E policies. By RDL 1/2012, enacted in January 2012, preferential tariffs, premiums and any other incentive for new renewable plants were abolished and, in particular, PV calls cancelled. Any new facility should onwards sell its electricity at wholesale market prices. The postponement of the support policy was labelled as temporary, but no reset date was scheduled. Currently, the Government is strongly commited to put an end to the growth of the tariff deficit and to reduce its debt service. Besides stopping the RES-E policy, other important decisions have been the increase of electricity rates (from 2009 to 2012 up to 23.42% excluding taxes, instead of 9.5% in the Euro zone and 9.2% in the UE-27, according to EUROSTAT, 2012) and the creation of taxes on generation. Spanish electricity retail prices are diverging from EU average.

The PV-DSG option was actually forgotten during the period 1998-2008. Although on-site generation was, in principle, allowed, customer-generators were directed to instantaneous consumption and home storage, and required to sell excess electricity at wholesale market prices. No measures regarding the promotion of any given PV-DSG scheme were placed. However, since 2008 the progressively reinforced cost-containment policy has given rise to different proposals in favour of PV-DSG. An example was the request of a PV association for the encouragement of on-site generation and net metering by means of FITs (ASIF/KPMG, 2009). More important was the National Renewable Energies Action Plan, which in June 2010 mentioned self-generation, together with the banking of excess energy, as a way of promoting PV investments (PANER, 2010: 50). A few weeks later the Renewable Energies Plan 2010-2020 (PER, 2011, §8.2) was published, It rejected FITs and previewed a PV-DSG regulation based on some kind of excess energy compensation. It was alleged that this way of promoting PV would engage a lot of consumers worried by the increase in electricity prices and/or climate change, without adding extra costs to the electrical system and damaging the interests of ratepayers (Mosquera, 2011).

The regulation of on-site generation started in March 2010 when, according to the Directive 2009/28/CE of the European Parliament, a decree draft simplifying the grid connection of ≤100 kW RES-E facilities was released (see §4 below). This document indicated that grid exchanges would have to be metered and rated (see below). In September, the National Energy Commission (*Comisión Nacional de la Energía*, CNE) issued a report on the draft proposing only some minor changes (CNE, 2010). But, instead of a final version ready to enter in force within a short period of time, a third draft was still diffused in April 2011.It delayed six months to set down "a procedure for rating and net balance compensation" (Proyecto, 2011: 14 and CNE, 2011: 21-22). After two years of waiting, RD 1699/2011 was finally published on 8th December 2011. Some days before, that is, on 18thNovember 2011, a decree draft specifically regulating on-site generation had been issued (MITYC, 2011).[10]

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pay the last resort tariff (*tarifa de último recurso,* in Spanish regulatory jargon). By the end of 2012, the accumulated tariff deficit had reached €29,000 m (~3% of the Spain's GDP). Most of this amount has been securitized and placed at the international financial markets.

[10] It should be noted that the RD 1699/2011 also bore the data of 18th November. The coincidence with the draft could be explained because this decree established four months, that is, until 9th April 2012, as the deadline for submitting a definitive proposal on on-site generation to the Government. This requirement has not been met yet.

2.2. *A Brief Comparison with other Policies Focused on FITs*

The Spanish PV boom-and-bust cycle is a good example of the virtues and risks of giving support to renewable technologies by means of FITs and premiums. An experience also shared, although with some particularities, by Germany and Italy. The comparison between them will undoubtedly shed light over the main design flaws and implementation drawbacks of FITs. On the one hand, they are indeed powerful kick-start market tools but, on the other, they are difficult to fine-tune. The deployment rate can actually spin out of control due to either the sector's internal factors (as, for example, the acceleration of downtrend costs) or those coming from the outside (in Spain, financial resources coming from the building industry). As a result, the interests of ratepayers could be severely damaged.[11] On balance, FITs and premiums are powerful propellants (encouraging investments) but need control valves (cost-containment levers) as transparent and automatic safeguard mechanisms.Transparency implies all the stakeholders participate in their definition and automatism refers to the fact that those mechanisms are ready to act without need of direct intervention. Unfortunately, uncertainty and asymmetric information shape the process of designing FITs. Thus, the expectations about the future trend of PV systems' prices can be flawed and key stakeholders could be inclined to provide biased information. Furthermore, past events also affect the set up of FITs. In Spain, authorities probably thought that a strong support would be the driving force for the development of a competitive domestic PV industry, as it was the case for wind power generation some years before. The most appropriate answer to these design shortcomings is probably to promote public debate.[12] Technically, several cost-containment mechanisms already exist, such as capacity caps, scheduled revisions, flexible degression, caps on total costs, limits on the amount of generation which is eligible for FITs and so on. The paragraphs below comment on them (see also del Río and Mir-Artigues, 2012).

The most interesting cost-containment mechanism is the FIT degression rate, which could take different forms, as Table 3 presents. To start with, the scheme is supposed to have a certain temporal validity (T). Beyond that point, authorities will revise the remuneration framework. However, an alternative to it would be to check out FITs after a given installed capacity is reached (R). Sometimes, both criteria hold. Regarding tariffs (p) they could be affected by a degression rate in four main ways (Mir-Artigues, 2012: 302-306):

1. Setting up a complete table of scaling back tariffs for the next periods (months, quarters, years, etc.). This is the administrative planned rule.
2. There is a fixed degression rate ($\bar{\delta}$) in force until the next tariffs revision.
3. Different capacity targets (q^t) are established and the degression rate changes ($\tilde{\delta}$) according to the level reached by the installed capacity (q^R). The greater the amount installed, the more the degression rate increases. Thus, tariffs go down more quickly (β>1). If any cap is reached, either the degression rate does not change (β=1) or tariffs are not modified (β=0) (the floor). This rule can develop

[11] The annex provides a simplified model showing the main cost drivers of a support policy based on FITs.

[12] Unfortunately, the Spanish regulation of energy issues has a lack of transparency. Actually, the Government, through the Ministry of Industry, decides the guidelines of the energy policy, as well as all the aspects of the regulation, including those regarding the remuneration of electricity producers. The regulator (the CNE), which promotes public debates amongst stakeholders instead of bilateral and discrete meetings, plays only an advisory role.

many variants. One of the most important is the growth corridor system (see below).

4. In responsive or flexible degression, the degression rate behavior is systematically and closely linked to the dynamics of the installed capacity (Couture et al., 2010: 40-41). Its first element is the maximum capacity that can be added ($\bar{q}$). Then, at the end of each period, the execution degree, that is, $\frac{\bar{q}-q^R_{t-1}}{\bar{q}}=\gamma_{t-1}$ is calculated. The degression rate will change accordingly. This tariff design could include one o more values for the parameter β_t, as well as different capacity caps. It also leads to a strong quantitative control is caps are small. This was the case of the RD 1578/2008, although the fixed degression rate was overcome by the reduction of module prices.

Table 3. Basic forms of tariffs degression rate

	Expression	Capacity target/volume	Validity
Administrative planned	$p_0, p_1, p_2,..., p_t,..., p_T$	R	T
Fixed	$p_t = p_0(1-\bar{\delta})^t$	R	T
Variable ($\tilde{\delta}$)	$p_t = p_{t-1}(1-\beta\delta)$	$q^t \geq q^R$, δ=1, orβ=0 $q^t < q^R$, δ>1	T
	$p_t = p_{t-1}(1-\beta_t\delta)$	$\frac{\bar{q}-q^R_{t-1}}{\bar{q}}=\gamma_{t-1}$, $0 \leq \gamma_{t-1} \leq 1$, $\gamma_{t-1} \rightarrow \beta_t$	T

Fixed degression was first introduced in the German PV policy in 2000 (at an annual 5%), as shown in Table 4, which outlines the milestones of PV regulation both in that country and in Italy.[13] Although this rule adjusts tariffs and cost reductions to some extent and, simultaneously, provides an incentive for technological innovation, its behavior is too passive. While prices change slowly, the framework runs acceptably well, but if things start to move quickly, it becomes a straitjacket. This happened in 2009 when modules prices plummeted and Germany replied introducing the corridor system. This reform assured that the capacity growth would still be controlled by price signals. By contrast, as it can be observed in Figure 3, neither Italy nor Spain set up an effective tariff degression rate system, and other cost-containment measures, until 2008.

From 2006 to 2008, designed Italian tariffs were comparative high: they were 5% below the German and, approximately, 25% bigger than the Spanish ones. However, irradiation levels in Italy are one third greater than in Germany and similar to those in Spain. This is evidence of Italy's strong support of PV generation and, moreover, of the fact it ignored the downtrend prices of panels. Despite the widely known Spanish bad experience, Italy maintained tariffs with practically no changes in 2009 and 2010. When in 2011 tariffs were finally reduced, they still remained 31%

[13] Comparing FIT policies is difficult because of the variety of elements they include. In our case, however, the comparison is focused on the tariffs behavior and remuneration. Data on policies mainly come from Fulton, Capalino and Auer (2012) and <www.gse.it>. The index of modules prices has been elaborated on monthly data published at <www.solarbuzz.com>.

higher than in Germany and Spain. In addition, it should not be forgotten that Italy excludes small-to-medium installations from caps on capacity and budget.

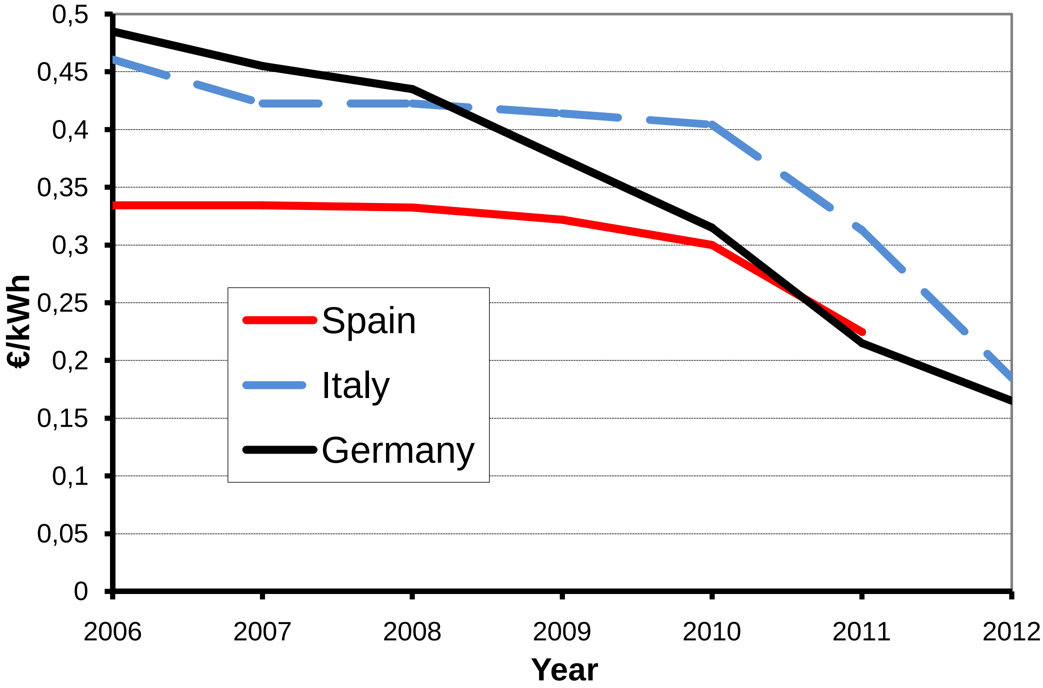

Figure 3.Average designed FITs in Germany, Italy and Spain

This average of FITs schemes has been calculated combining each year's lowest and highest tariff (or those of another span of time in which FITs were defined) according to size and applications (BIPV, free-standing, etc.)

* In 2012 the Spanish RES-E support policy ended

Source: Own elaboration

Since 2011 Italy faces a deep economic crisis. The Fourth Energy Bill and, specially, the Fifth Energy Bill tried to bring some order to what was described as a chaotic market. From mid-2010 to mid-2011, that is, the last period of the Second Energy Bill and throughout the short living period of the Third Energy Bill, the capacity increase was out of control. As in the Spanish boom two years before, the reduction of FITs took too long. As a consequence, the number of installations soared (almost 5 GW were installed in a few months).

Both Italy and Spain had to readjust their preferential tariffs along 2010 and 2011 due to the rapid decrease of PV prices. Meanwhile, Germany shortened the corridor adjustment period: it was decreed that it will be readjusted every half year. German authorities succeeded in this, although small rushes took place just before tariffs' revisions, that is, in June (2.1 GW were installed) and December 2010 (1.2 GW), and June (1.2 GW) and December 2011 (1.5 GW). In Italy, the Fourth and Fifth Energy Bill entailed tough tariffs reductions which cut the capacity expansion rate. At the same time, compelling economic targets were set up for the following years. Despite the problems in common, there is no doubt that the German FITs matched the dynamics of PV prices better than Italy and Spain.

Table 4. The PV support policies in Germany and Italy, and module prices

<table>
<tr><th></th><th colspan="2">Germany</th><th colspan="2">Italy</th><th>Module prices</th></tr>
<tr><th>Year</th><th>Policy</th><th>MW</th><th>Policy</th><th>MW</th><th>€/kWh 2001=100</th></tr>
<tr><td>2000</td><td rowspan="9">Erneuerbare-Energien-Gesetz (EEG) (Feed-in Law)
2000-2003: FIT €cents 51/kWh
Fixed degression rate: 5%/year
100,000 PV roofs program: zero interest rate loans
Size capped 2 MW (roof), 100 kW (ground-mounted)
Indicative capacity targets
Amendment 2004: FITs and degression rates by size and application
Amendment 2008: degression rate ground-mounted plants 6.5%
All caps eliminated</td><td>44</td><td></td><td>0.5</td><td>…</td></tr>
<tr><td>2001</td><td>110</td><td rowspan="5">PV promoted by investment subsidies for rooftop installations
2003:Conto Energia (Energy Bill)</td><td>1</td><td>100</td></tr>
<tr><td>2002</td><td>110</td><td>1.9</td><td>95.4</td></tr>
<tr><td>2003</td><td>139</td><td>4</td><td>88.5</td></tr>
<tr><td>2004</td><td>670</td><td>5</td><td>85.3</td></tr>
<tr><td>2005</td><td>951</td><td>5</td><td>87.2</td></tr>
<tr><td>2006</td><td>843</td><td rowspan="5">February 2006: Primo Conto Energia (First Energy Bill)
Tariff guaranteed for 20 years, without adjustment to inflation
FIT premium over the market price of electricity
Annual 1.7%-2% FIT decrease
Sizes: 1 kW-20 kW, 20 kW-50 kW and 50 kW-1 MW.
February 2007: Second Energy Bill
Tariffs reduced 2% each year
<20 kW net billing scheme with delayed consumption rights for 3 years
Maximum capacity eligible raised by acceleration installed
Rush since mid year</td><td>12</td><td>88.3</td></tr>
<tr><td>2007</td><td>1,271</td><td>77</td><td>87.5</td></tr>
<tr><td>2008</td><td>1,809</td><td>345</td><td>85.7</td></tr>
<tr><td>2009</td><td rowspan="2">Corridor system: FIT degression rate for the following year according to the volume installed in the previous year (or in several months of the previous year)
Corridor and change degression rate set up based on PV experience curve expectations and electricity bill impact forecasts
Corridor5.5%-7.5%, but not enough due to modules prices downtrend
July 2010: degression rate 8%-13%
Rush in June and December</td><td>3,806</td><td>712</td><td>73.8</td></tr>
<tr><td>2010</td><td>7,400</td><td>2,325</td><td>60.6</td></tr>
<tr><td>2011</td><td>Interim revision:1 point added to 2011 degression rate for each GW installed in excess with respect 3.5 GW baseline 2010
Rush in June and December</td><td>7,500</td><td>January 2011: Third Energy Bill
Sizes: 1-3 kW, 3-20 kW, 20-200 kW, 200 kW-1 MW, 1-5 MW and >5 MW.
Two types of emplacements: BIPV and others. Variety of bonuses
Average reduction of tariffs: 14%.
Second Energy Bill regime extended to 30 June 2011.
Rush during the first semester
May 2011 Fourth Energy Bill
Tariff decrease monthly: reduction 31% respect Second Energy Bill.
Targets on spending and installed capacity for ground-mounted plants
Project registration procedure coupled with a ranking priority
Excessive demand 2011: the budget for the second half of 2012 is zero
No more registrations of large plants
Large installations excluded rooftop <1 MW and ground mounted <200 kW</td><td>9,304</td><td>47.8</td></tr>
<tr><td>2012</td><td>EEG 2012: Market premium system: RES-E electricity sold in wholesale market plus premium
FITs 2012 declined by 24%
Mid-year amendment: rates onwards adjusted on a monthly basis
Goal of 52 GW capacity 2019-2022</td><td>7,600</td><td>July 2012: Fifth Energy Bill
Expenditure ceiling € 6.7 billion (all installations included)
In September amount exhausted</td><td>3,350</td><td>40.3</td></tr>
</table>

3. Types of PV-DSG and their Economic Features

As it is widely known, the promotion of the grid-connected photovoltaic generation has been focused, with varying intensity depending on the country and period, on two main types of installations:

- The utility-scale PV plants which have benefited from FITs, premiums and TGCs., even though big plants (tens of MW) have been mostly deployed according to tendering or auction schemes. All these medium-to-large size facilities have been installed on roofs of big commercial and industrial buildings, as well as ground-mounted. The largest are directly connected to the transport network.
- In PV-DSG, modules and BoS components are installed on the customer's side of the meter. Therefore the consumption and generation segments are placed either physically or economically side-by-side. Modules are placed on the roofs and façades of residential houses or small commercial buildings. Sometimes, they can be ground mounted. In such a case, they are usually located near the area where their shareholders live. All these facilities are small-to-medium sized and involve some kind of energy exchange with the distribution grid. As a result, a new agent is gaining momentum in the electricity sector: the customer-generator.

The next pages provide a general classification of the PV-DSG modalities and a description of their economic features.

3.1. *Types of PV-DSG*

There are several types of PV self-generation.[14] Table 5 presents their classification combining two criteria: the proportion of on-site consumed[15] electricity coming from the generation system itself, and the sign of the grid exchanges (exports minus imports, or X-M)at the end of a given period of reference (normally the billing cycle[16]). The capacity of the on-site generation system (Q) is equal or minor than the household/s demand load (Θ) for all types of PV-DSG.[17] Moreover, this classification mostly mirrors the current situation: costs of self-generation are higher than the retail prices. But things are changing.

Customer-generators with their electricity needs only partially covered from its own plant, are located in the first row, first column of the table. They must usually import electricity from the distribution grid, but sometimes they have an excess energy to export. In any event, at the end of a given billing cycle, there is a net imports balance. Three variants can be distinguished:

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[14] In this paper the concept of self-generation is preferred over that of self-consumption because generation comes before consumption. Nonetheless, both terms can be used interchangeably.

[15] As previously pointed out, the electricity can be directly consumed or translated into an economic benefit. In this latter case, the energy on-site generated is not consumed, not even a fraction, and is sold to the distribution company in order to pay for the electricity purchased from the grid.

[16] There are registering periods $[0, p_R]$ and billing cycles $[0, P]$. The relation between them is given by the expression, $[0, P]=\delta[0, p_R]$, $\delta\geq 1$. Balances at the end of registering periods have no economic effects.

[17] The main goal of the customer-generator is self-consumption. Therefore, it is assumed that he/she will maintain the basic features of his/her electrical infrastructure and grid connection. If the on-site PV generation system is planned to tap all the available space, regardless any other consideration, the project is mostly commercial. This is distributed generation, not distributed *self*-generation. This is the case of the PV plants located on roofs, façades or courtyards which electricity is sold, probably at preferential prices. The users of these dwellings, warehouses or industrial sheds will purchase electricity from the grid because of its comparative lower price. Therefore, own demand is not satisfied by the PV installation.

- The instantaneous self-consumption with imports and excess exports. In this case, generators take advantage of FITs for the self-consumed and exported electricity, because customer's side electricity is more expensive than that purchased from the grid. Sometimes there could be other advantages, such as investment subsidies, soft loans, etc. This situation is common in countries which PV policy has given priority to the roof-mounted residential plants, such as Germany, Italy or Japan.
- The net metering rule means that generators only have one bi-directional meter which runs both forward or backward. Therefore, exports and imports are quantified in physical terms (kWh). In this situation, consumer-generators are granted upfront subsidies, soft loans, tax rebates and so on.
- In the net billing modality there are two meters (or only one with two independent metering devices) in order to separately gauge exports and imports, because they have different prices. Therefore, energy exchanges are expressed only in monetary terms. The price for the exported electricity, or buy-back price, could be regulated (FIT) or freely negotiated between the customer-generator and the distribution company. The self-consumption is supported through FITs or other advantages.

Table 5. Types of PV-DSG

<table>
<tr><th colspan="2" rowspan="2">PV self-generation
($Q\leq\Theta$)</th><th colspan="3">Self-generated electricity</th></tr>
<tr><th colspan="2">Partially on-site consumed</th><th>Totally on-site consumed</th></tr>
<tr><td rowspan="5">Grid exchanges</td><td rowspan="4">Net electricity imports
($M\geq X$)</td><td rowspan="3">On-site</td><td>Instantaneous consumption with FIT</td><td rowspan="4">Instantaneous consumption with no exports</td></tr>
<tr><td>Net metering</td></tr>
<tr><td>Net billing</td></tr>
<tr><td colspan="2">Off-site</td></tr>
<tr><td>Net electricity exports
($M\leq X$)</td><td colspan="2">Zero net energy</td><td></td></tr>
<tr><td colspan="2">No grid connected</td><td colspan="2"></td><td>Off-grid</td></tr>
</table>

Source: Own elaboration

This group also includes the off-site generation (or solar gardens). In this case, one person or, what is more common, k ($k\in[1, K]$) people (the subscribers o shareholders group) own a small-to-medium sized grid-connected facility. It is located beside/near a multifamily housing property such as an apartment block, a neighbourhood or a condominium. The installation was usually directly promoted by the group or by third parties. Sometimes solar gardeners may have invested in an off-site installation promoted by third parties. It should be stressed that all of the subscriber's electricity comes from the grid (Coughlin and Cory, 2009, §9). Therefore, the electricity generated by the off-site plant is completely sold. As a consequence, the off-side scheme is like an indirect net billing: the value of the energy exported to the grid will partially compensate the electricity imported from the grid. As could be expected, exports are backed by FITs or premiums. Finally, another typical feature of the off-side modality is that a solar service provider manages the installation.

Leaving aside off-grid generation, on-site modalities are the most widespread forms of grid-connected PV-DSG (LCEA, 2012; RMI, 2012). Obviously, there are countless specific situations depending on three factors:

- The daily, weekly and seasonal curves of consumption and self-generation, which give rise to different patterns of electricity imports and exports.

- The economic terms and conditions shaping the electricity exchanges between the customer-generator and the distribution company.
- The technical and administrative rules to be met by promoters, which can either encourage or dissuade on-site generation.

Each customer-generator is a particular combination of these factors. Nonetheless, their economic appraisal dramatically changes depending on the relationship between the self-generation costs and the retail prices (which are probably higher for residential than for commercial and industrial ones).

A variant of instantaneous consumption appears in the first row, second column of the table: the whole self-generated electricity is consumed on-site, so there is no excess to be exported. The aim of this installation is to reduce to some extent the electricity bill. This may be an economic option only and only if the self-generation cost is lower than the retail prices or, in other words, only if PV generation has reached ratepayer prices. However, on the one hand, this type of demand-side generation has a strong shortcoming: both generation and consumption vary with time. The highest generation is at noon and in the afternoon, while at night it is zero. The consumption varies depending on the number of daylight hours, with probably lower levels at night and on weekends and holidays. As a result, the on-site installation will have a limited power in order to avoid excess energy. Therefore, it will not cover a significant portion of the consumption. For that reason, this type of PV-DSG could be only interesting for activities with a steady and permanent consumption of electricity, such as hospitals, retirement houses, fire stations, certain kinds of greenhouses and battery farms, cold stores, etc. On the other hand, this type of application will be adopted only in case of a lack of an appropriate regulation of the demand-side generation. Actually, consumer-generators will always prefer instantaneous consumption with electricity exchanges provided that a friendly regulation of PV-DSG has been issued.

Zero net energy (second row, first column) is characterized by the absence of net electricity imports from the grid ($M \leq X$) at the end of the billing period. Although no consensus exists, zero net energy projects, usually new or fully refurbished buildings, are defined by “achieving a net-zero energy balance annually through intensive energy efficiency and on-site renewable generation” and “it is a project with no net purchases of energy from the grid” (Lacy and Buller, 2012: 3). The consumer-generator "wanted to produce as much renewable power on-site as he consumes from the grid, pursued energy efficiency before adding a large PV array on his roof" (RMI, 2012, 28). This implies a broad implementation of efficiency and saving measures, as well as storing energy systems.[18]

Finally, the table includes the off-grid (or dispersed) generation. In such case, all the electricity needs must be covered by the on-site installation. Therefore, batteries will be required due to the intermittency of the PV generation.[19]

3.2. *Economic Features*

After reviewing the different types of PV-DSG, it is time to describe their economic features. To begin with, the on-site modalities’ notation is presented below,

q_t annual generation (kWh) of the on-site system
θ_t annual electricity demand (kWh) of the customer-generator
w_t retail electricity price (€/kWh)
w_t^* electricity buy-back price (€/kWh)
p_t feed-in tariff (€/kWh)

[18] This possibility also implies that there is no point in considering an off-site zero net energy option.
[19] It should be pointed out that the on and off-site applications have no batteries because the grid itself is used as a big battery.

e_t wholesale market price (€/kWh)

The future customer-generator wishes to install a PV facility without changing the basic features of his/her electric infrastructure and grid connection, so $Q \leq \Theta$.Then, the annual volume of electricity produced by the system is given by,

$$q_t = Q \cdot L \cdot H$$

being Q the capacity (kW) of the system, L the load factor (~20% in PV generation) and H=8,760 hours. Hence, the *expected* lifetime value of the electricity generated by the on-site generation plant (S) is,

$$S = \sum_{1}^{T} q_t \cdot w_t \qquad [1]$$

where w_t is the electricity retail price (€/kWh) and [1, T] is the lifetime of the generation system. Finally, the expected net present value (V_0) of S is written as,

$$V_0 = q \sum_{1}^{T} \frac{w_t}{(1+i)^t}$$

For the sake of simplicity, it is assumed that a steady amount the electricity is annually generated.

At the same time, the investment to be afforded by the customer-generator is I_0=Q· (€/kW). Thus, the financial cost associated to such investment (in constant annuities) is,

$$a = I_0 \frac{i(1+i)^T}{(1+i)^T - 1} + m$$

Again for the sake of simplicity, the annual O&M expenditures (m) are assumed constant over the lifetime of the system. In addition, the length of the amortization period has been selected to match the lifetime of the installation. As it is obvious, a/q_t is the on-site generation cost by kWh.

Based in this model, the economic analysis of on-site generation includes two parts:

- The first one is the comparison of S and $C=aT$, being C the *real* lifetime cost of the self-generated electricity.[20] Thus, if $S>C$ (project savings) the expected lifetime value of the electricity on-site generated is higher than the accumulated amortizations and O&M expenditures. By contrast, if $S<C$ (project losses) the investment and operational outlays are not overcome by the potential value of the electricity generated by the installation. The value of S depends on w_t, q_t and T, while C is mostly affected by I_0, T and i.
- The second one is the net exchange balance, that is, the comparison between the electricity exports and imports. It should be taken into account that there are many possibilities when it comes the evaluation of these energy streams: in physical terms, at retail prices (w_t), at given buy-back prices (w_t*), at FITs (p_t), etc.

As for the basic economics of off-site generation, the first expression to be taken into account the general restriction,

$$\sum_k Q^k \leq \sum_k \Theta^K$$

related to the K subscribers' community. Then, the *expected* lifetime revenue of the subscribers' community (R^k) is given by:

$$R^k = \sum_{1}^{T} q_t^k \cdot p_t$$

[20] This comparison has been called the avoided cost, that is, the "difference between what the customer-generator would have paid the energy supplier without the generation equipment and what is paid with the equipment" (Hughes, 2005: 4).

being q^k_t the annual electricity (overall fed into the grid) generated by the facility belonging to the community of k customer-generators. Therefore, R^k should be compared with the expected lifetime expenditures, namely, the electricity purchased, the amortizations of the up-front investment and the accumulated O&M outlays,

$$\sum_{1}^{K}\sum_{1}^{T}\theta_t^k \cdot w_t + a^k T$$

if the whole electricity consumed by the community is assumed to be purchased at retail price. Denoting this sum by E^k, the economic viability of off-site generation would be given by the expression,

$$R^k \geq E^k \qquad [2]$$

This relation mostly depends on the values of p_t and w_t.

It is worth pointing out here that these models, which have been built from the consumer-generator point of view, ignore benefits such as upfront subsidies, tax rebates, etc. Whereas some of these advantages reduce the investment effort, others affect the revenue of the customer-generator/s.

Besides, we have not paid attention neither to the general features of the PV-DSG promotion policy, such as caps and hourly restrictions on energy exports or ceilings on the amount of the electricity demand to be supplied from PV-DSG systems, nor to the general limits which have been prescribed by several regulations, such as the restriction of the volume of electricity coming from demand-side generation (currently capped at a small percentage of the overall electricity demand or, alternatively, at a fraction of the peak load).

Other general aspects such as the decoupling rule (that is, utilities claim that rates should be adjusted if their revenues go down due to the diffusion of demand-side generation), the net costs for ratepayers and the equity impacts of the on-site generation (CPUC, 2010; Darghouth et al., 2010; Weismann and Johnson, 2012; Neuhoff et al., 2013), etc. have not been considered either.

Finally, althoughq_t and θ_t have been defined in annual terms, it should be pointed out that the power generated by a PV system varies. As a matter of fact, it probably produces more than is needed during daytime, particularly at midday and in the afternoon, when the PV output is at its greatest, while there is a substantial decrease of electricity production in the evenings and at night. Even during the sunny hours, the electricity generation may vary due to fluctuations in the irradiation flux, sudden weather changes, unforeseen system failures, etc. Electricity imports are expected to be at their smallest level during weekends and holidays as well. Whether hourly, daily, weekly or seasonally, several gaps between production and demand appear (Widén and Karlsson, 2010).

In order to continue with the economic analysis of PV-DSG types two general situations are distinguished: when retail grid parity has not yet been reached (that is, $a/q_t>w_t$) and when it is reached ($a/q_t\leq w_t$).

3.3. *The PV-DSG before Retail Grid Parity* ($a/q_t>w_t$)

Instantaneous self-consumption coupled with energy excess is backed with preferential prices (p_t). As it has been indicated, FITs (combined with other advantages such as preferential prices for self-consumed electricity -feed-in compensation-, investment subsidies, soft-interests loans, etc.) are necessary because customer's side electricity is more expensive than that purchased from the grid. Therefore the initial situation [1] becomes,

$$\hat{S} = \sum_{t=1}^{t=T} q_t \cdot p_t \qquad [3]$$

so that $\hat{S} = C$ and the on-site project is financially viable. The exchange expression is,

$$\sum_{1}^{T} X_t p_t - \sum_{1}^{T} M_t w_t < 0$$

because the amount of exports, even with FITs, is lower than that of imports. The intermittency of PV generation results in significant electricity imports at retail prices. Conversely, just occasional energy surpluses can be fed into the grid.[21] Figure 4 shows what happens in a typical business day. The PV generation starts at sunrise (t_1) and stops at sunset (t_4). At t_2, the level of self-generation meets the consumption and thereafter an energy surplus is produced. By contrast, at the time t_3, the on-site generated electricity falls below the demand. Hence, energy excess fades away. Between (0, t_2) and (t_3, 24) electricity must be imported to some variable extent, its cost being partially compensated by the surplus exported during the daylight hours (which has been represented below the horizontal axis to make it more visible).

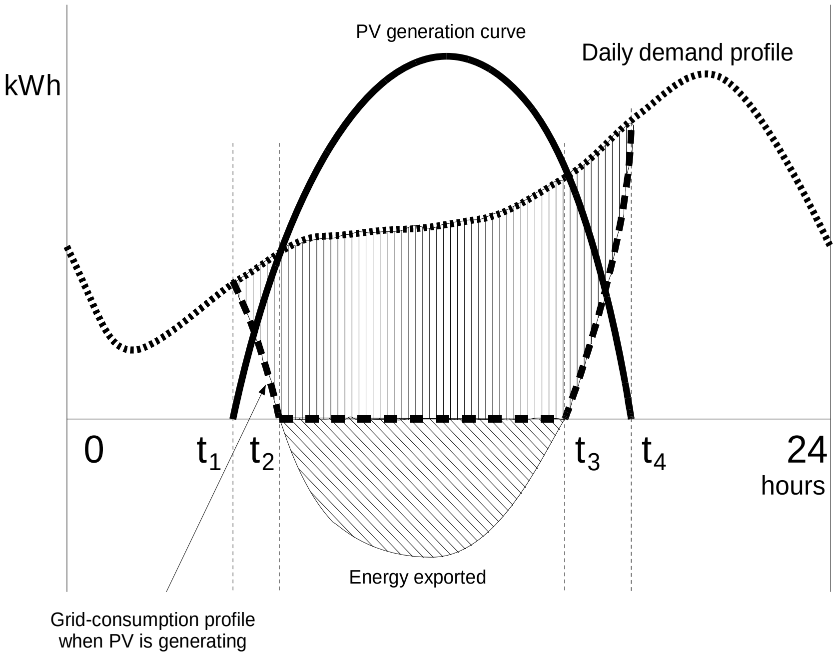

Figure 4. Self-generation with exchanges
Source: Own elaboration

This framework can be applied to all on-site modalities. The only differences are the specific economic conditions established by the electric system authority. Thus, for the net metering option, characterized by individually owned facilities (although not necessarily so) and equipped with one bi-directional meter able to separately record exports and imports, the expression regarding the avoided cost could be modified as follows,

$$\hat{a} = (1-\gamma)I_0 \frac{i(1+i)^T}{(1+i)^T - 1} + m - \gamma I_0$$

since the upfront investment has been divided in two parts in order to include an associated subsidy:[22]

$$I = \gamma I + (1-\gamma)I \text{ , } 0<\gamma\leq 1$$

The term γI represents the upfront investment subsidy and $(1-\gamma)I$ refers to the portion of the initial outlays which are financed by the customer-generator's own funds. By assumption, the

[21] This assertion excludes the case of second homes: since these houses are empty most of the time, the generation level is higher than the consumption and, as a result, net exports are achievable. However, second homes and those unoccupied are normally excluded from PV-DSG support policies.
[22] By definition in this case there is no FIT or premiums.

promoter pays the upfront investments, and the subsidy (γI) is granted before the plant operation begins Therefore, the avoided cost becomes $S = \hat{a}T$. Regarding the exchange rule, we have to consider,

$$\sum_1^T X_t - \sum_1^T M_t < 0$$

Energy streams are measured in physical terms. The net balance is just a statistical matter.

The net billing modality involves two meters (or only one with two independent metering devices) because energy streams are differently valued. In this case, the avoided cost expression is,

$$\hat{S} = \sum_1^T q_t \cdot w*_t$$

which is very close of [3] because the buy-back price could probably be a FIT or a premium. The grid exchange terms combines the fact that occasional exports will be earned, banked or lost, while net imports will be paid. Therefore, if the annual energy exchange (Y_t) is defined,

$$Y_t = X_t w_t^* - M_t w_t$$

the expected lifetime revenue coming from the energy exchange (Y) will then be,

$$Y = \sum_1^T X_t w_t^* - \sum_1^T M_t w_t$$

In normal situations, $Y \leq 0$ is expected.

The expression [2] indicates that the off-site case is financially viable if and only if the electricity is exported at a price higher than the retail price, for example, at a given FIT or premium. However, it is important not to forget that the larger a plant is the lower the upfront costs are. Therefore, economies of scale give rise to comparatively low remuneration. This is the advantage of the off-grid modality. In any event, exports should pay for imports and cover the facility amortization and the O&M expenditures.

The outstanding feature of zero net energy is that at the end of every reference period, as well at the end of the installation's lifetime, there are no net imports of electricity, that is,

$$\sum_1^T X_t w_t^* - \sum_1^T M_t w_t \geq 0$$

To achieve this goal, own demand (θ_t) is reduced as much as possible (therefore an increasing portion of q_t will be exported) by investing in energy savings and efficiency improvements. This is a good strategy, but the customer-generator has to afford both the amortization of the upfront cost and the amortization of investment for the energetic enhancement of the building, and the O&M outlays. This could be achieved through appropriate buy-back prices or other advantages such as investments subsidies, soft loans, tax rebates, etc. either for the PV plant or for the savings and efficiency measures. As a result, at the end of the billing cycle the customer-generator will probably make money.

3.4. *Reaching the Retail Grid Parity ($a/q_t \leq w_t$)*

The economics of the PV-DSG modalities change when grid parity is reached. In our simplified model it means $a/q_t \leq w_t$, that is, the energy coming from the grid is progressively more expensive than self-generated energy.[23] However, it should be highlighted that, on the one hand, S is calculated assuming a given w_t increase and, on the other, a/q_t is actually an estimated value (the leverage cost of electricity, LCOE). Or, in other words, the relation $S>C$,

[23] Wholesale grid parity will not be taken into account along these pages. In such situation PV generation, or any other RES-E, would become competitive with conventional technologies such as nuclear, generation, hydroelectricity and NGCC. This fact will usher in new energy policies and regulatory frameworks.

or (S-C)>0, is under the influence of several factors: irradiations levels, efficiency improvements, equipment lifetime, regulatory amendments, etc. Moreover, on-site generation probably faces a higher cost of capital to finance the upfront investment than that applied to a loan requested by a commercial plant. Actually, from the lender perspective the retail parity and the FIT (even if it is just understood as a guaranteed price) are not the same: the former generates savings, the second earnings. Anyway, the result is that the spread of the PV-DSG will only happen progressively because retail grid parity varies on a case-by-case basis.[24] Nonetheless, retail grid parity will in principle encourage three types of PV-DSG, namely, off-grid generation, immediate on-site consumption without exports and the instantaneous consumption coupled with the sale excess electricity.

Following the achievement of retail grid parity, off-grid self-generation will increase, especially if the cost of storing electricity is also offset. In terms of our model that means that the point S=C* has been reached, and thereafter S>C*, being C* the sum of amortization annuities for both plant and storage system, and also both O&M expenditures. Going beyond the retail grid parity point, everybody sees the off-grid option progressively opened regardless the distance to the network. Nonetheless, ratepayer prices may go down in the medium term.

The second scheme is the instantaneous consumption while avoiding exports. As it was previously pointed out, in activities with steady and permanent demand, it is possible to install relatively large PV plants in order to offset the purchase of electricity. See Figure 5. In this case, profile of the daily demand is roughly flat, therefore a PV plant, which largely contribute to on-site consumption, has been installed. Of course, the energy located between the demand profile line and the shaded area (or the PV generation curve) is imported from the grid.

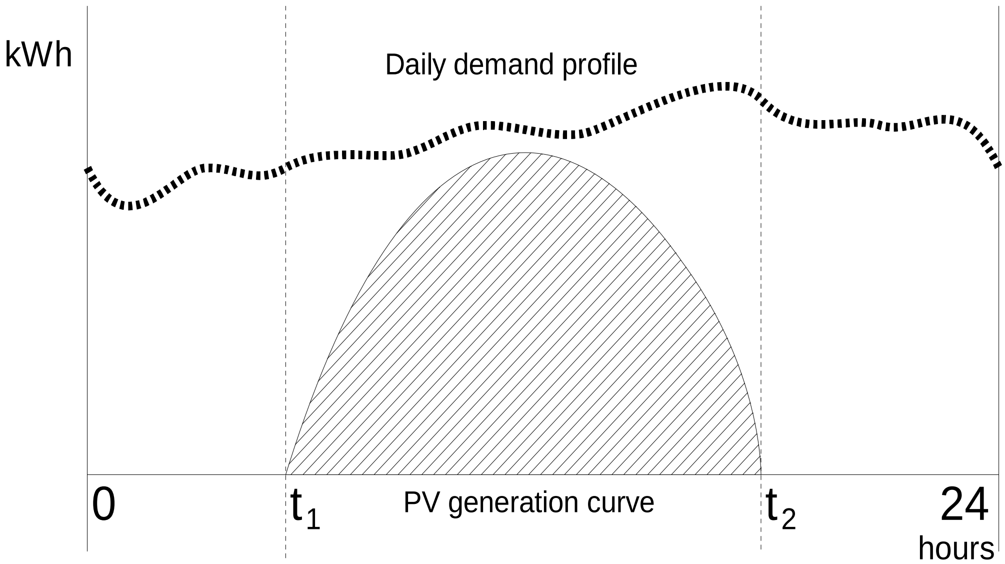

Figure 5. The instantaneous consumption in case of steady and permanent demand
Source: Own elaboration

The lifetime economic expression to be considered is,

$$\sum_{1}^{T}\theta_t w_t - C$$

[24] An equal cost is indeed a necessary but no sufficient condition for promoting the diffusion of an emerging technology. As the history of technology shows the (direct or efficiency pondered) cost of a novelty should be visibly below the currently available technology in order to overcome the multiple circumstances (legal, lobbying, etc.) that hinders its diffusion.

that is, the expected value of the overall electricity needed minus that produced *in situ*, given that $\theta_t > q_t$.

Before closing this point, it should be again stressed that this type of PV-DSG is just a market niche. Consequently, it could be the current focus of PV investments in places without either technically or economically friendly regulation of demand-side generation. In such cases, organized interests against it and regulatory uncertainty will discourage potential investors. But without specific rules promoting PV-DSG and electricity exchanges, this modality cannot be extended to residential uses and small businesses as Figure 6 shows. The very low demand profile on holidays and weekends compels customer-generators to install PV plants which are much smaller than ideal. Most of them will conclude to afford to it is worthless.

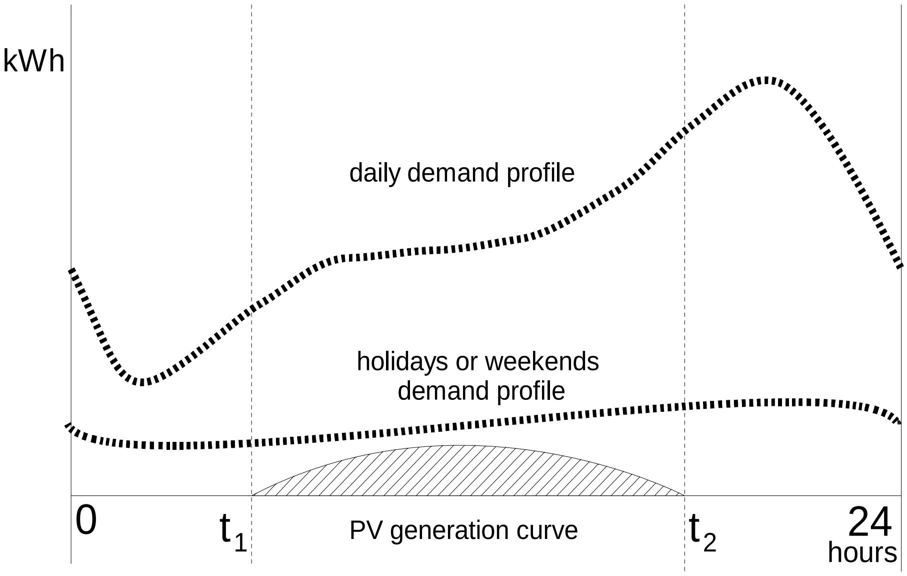

Figure 6. The instantaneous consumption in case of demand variability
Source: Own elaboration

The third option is the instantaneous consumption coupled with the sale of excess electricity, at least at wholesale market prices (e_t) and its purchase at retail prices. In our model notation,

$$(S-C)+\left(\sum_{1}^{T} X_t e_t - \sum_{1}^{T} M_t w_t\right) \qquad [4]$$

Now, S≥C without incentives, that is, self-generation is always justified, but the exchange can damage this advantage because $e_t < w_t \leq a/q_t$. Therefore, given the intermittency of the PV source and the variability of demand, which inevitably entails excess energy and energy deficits, the economic results of this particular version of net billing will depend on the conditions regarding volumes and prices of exchange.[25] Of course, any initiative to save energy and improve the efficiency will reduce demand and, hence, imports. This benefits consumer-generators.

In general, after reaching retail grid parity, while net metering will be abandoned, the discussion about the details of new net billing schemes will probably rage. Many questions will emerge in this context:

- Should we keep supporting PV-DSG? If so, how should the new FIT scheme be?

[25] The analysis is definitely more complicated because spot prices will sooner or later react to retail grid parity and the spread of PV-DSG, but to foresee their dynamics and impacts on the merit order effect is truly complex. This question falls beyond the scope of these pages.

- What should the fiscal treatment of customer-generator be?
- How should access charges and other general expenditures of the electric system be distributed among customers-generators, utilities and mere ratepayers?
- To what extent should on-site storing electricity be promoted?

Some experts are in favor of maintaining some kind of FITs, especially for PV-DSG. They propose to move from the current FITs to a long term contract selling(costumer-generators are actually unable to consumer on-site all the electricity they produce). New FITs may be established below retail prices (what is advantageous for ratepayers) and above wholesale market prices.[26] Doing that, FITs evolve from preferential prices to guaranteeing prices. An example in this direction is last German FIT proposal. This regulation set up a market premium model (Fulton, Capalino and Auer, 2012) featured by,

- All the RES-E generators sell directly in the wholesale market.
- In addition to the spot market price, generators receive a premium, calculated on a monthly basis, equal to the difference between a given FIT and a reference price.
- The reference price is the difference between the average wholesale market prices of the previous month minus the so-called management premium (an estimation of the costs incurred by generators in accessing the pool, such as fees for admission, trading connection, preparing forecasts, etc.).The greater the management premium, the lower the reference price and, as a result, the greater the market premium.
- Management premiums and FITs are technology-specific and decline annually.

The goal of this remuneration model is to promote demand-side generation, encouraging simultaneously the customer-generators to access the wholesale market. At the same time the prospect of an amount of electricity coming from demand-side generators could lead utilities to reduce retail prices in order to push parity further into the future.

4. The RD 1699/2011 and the Decree Draft

After reviewing the different types of the PV-DSG, it is time to return to the Spanish regulation of the on-side generation. As it was previously mentioned, this regulation is based on the RD 1699/2011 in force from December 2011, as well as on a decree draft released on November 2011 whose final version is still pending (March 2013).The content of both documents is described in the following points, with priority given to the decree draft proposal because it contains the economic conditions for the PV-DSG.

- **Consumers or consumer-generators?**The consumer-generators are only considered as special consumers. The text does not actually include the concept of consumer-generator. However, in a report issued by the regulator it was advised that considering PV-DSG adherents as consumers would put in risk the purchase obligation of RES-E electricity (CNE, 2012: 11). The regulator also added that consumer-generators would be registered, but only for statistical reasons.
- **Capacity**. On-site nominal capacity should be not greater than the customer's load. Moreover, it is capped at 100 kW. The RES-E sector requested this ceiling to be remove arguing that the grid capacity and the limited time span for rolling out excess electricity (see below) actually constrained the investments on capacity (CNE, 2012: 2). This cap also excludes the possibility of installations belonging to supermarkets, malls, office buldings, factory farms and so on. It should be also noted that the RD 1699/2011 fixed a short approval procedure for installations below 10 kW.

[26] In 2012, the highest German FIT, that of the systems <10 kW, was below the retail electricity price. However, it is expected this circumstance will give rise to the spread of the PV-DSGfrom 2017 onwards (Fulton and Capalino, 2012: 23).

- **Technologies permitted.** All renewable technologies (PV, wind power, CSP, etc.) and co-generation facilities are allowed, as established by the RD 1699/2011 and the decree draft.
- **How many meters?** Consumer-generators can install either one bi-directional meter or two meters. It is important to point out that meters with a counter mechanism which runs either forward or backward are not allowed. Therefore the Spanish proposal rejects the net metering modality and opts for net billing, which was to some extend foreshadowed by the RD 1110/2007: facilities selling only excess energy can use one meter provided that it holds two independent registering devices (one for generation, the other for consumption). However, this requirement was judged unsatisfactory for the regulator: the bi-directional meter must be synchronized with another meter registering the gross energy generated (CNE, 2012: 20). Furthermore, these meters should have hour accuracy. Finally, the RD 1699/2011 and the decree draft establish that the consumer-generator is responsible for keeping the meters in good condition.
- **Baking excess electricity and the duration of delayed consumption rights**. Exported energy is understood as the net feed-in amount at the end of the billing period (one month). Therefore, excess energy compensated within the same month has no economic effects, but in this case the draft does not literally forbid the metering service fee (see below). Monthly excess energy feed-in is not sold but banked for compensation. After 12 months, electricity is delivered for free.[27] Net excess energy takes therefore the form of delayed and time-bound consumption rights.[28]This was a very controversial point. For example, the CNE (2012: 3 and 27) agreed to this limit arguing that PV-DSG subscribers could not become net generators.[29] Some RES-E associations proposed 18 months, while others considered there should be no temporal limit. Third voices added that the expired rights could be valued at wholesale electricity prices. Very different was the utilities proposal: just 3 months.[30] Besides the imports as compensation, there are also extra purchases of electricity (see below).
- **How should electricity streams be valued?** The decree draft only indicates that the montly feed-in energy should pay the *generation* access charge.[31] Then, because electricity is transferred in physical terms (a given amount of kWh), the consumer-generator has a period of 12-months to import the same energy volume. According to the draft, the electricity imported as compensation should pay the access charge and the metering service fee (see below).[32] Therefore, each month (the billing period) the customer-generator will pay certain amount of money depending on the kWh exported and/or imported as compensation. The additional electricity imported by the consumer-generator, that is, the energy not covered by previous exports, will be

[27] This span of time was regarded as the most appropriate because it encompasses the whole seasonality of consumption and production cycle (Mosquera, 2011: 25). However, a year, although not prohibited, is too short interval for second homes.

[28] The initial data of a given delayed right is established by the distribution company.

[29] If customer-generators earn nothing from the electricity exchange, they do not pay income taxes.

[30] Because selling the electricity for free cannot be justified, shortening the validity of the delayed consumption rights acts as a restriction on the capacity of the facility and compels the customer-generator to waste electricity.

[31] The access charge was established by the RDL 14/2010 and implemented by the RD 1544/2011. Its value is €0.5 per MWH. It is paid from 1st January 2011.

[32] In Spain, the liberalization process led vertically-integrated utilities to be divided in generation, distribution and commercialization companies. Although they are formally independent, the electricity sector has retained its traditional oligopolistic structure.

purchased at prices freely negotiated between his/her and the commercialisation company. The regulator found this mechanism too complicated and insisted that both exports and imports had to be directly valued according to the prices freely negotiated by the parties (CNE, 2012: 22ff).Public utilities backed this position.

- **What about self-consumed electricity?** The draft establishes that all the electricity consumed by the on-site generator must pay the access charge (article 9.5, 2nd paragraph). This requirement includes self-consumed electricity as well as the extra energy imported (negotiated excluding this charge) and also the imported as compensation (as the draft explicitly establishes).
- **The metering service fee**. The draft warns that energy streams should be regularly and strictly metered. The distribution company will do this job and the consumer-generator will pay for it. The draft also indicates that the Ministry responsible of energy issues will establish the maximum charge for this service. The CNE thinks that it rather is a job for the market (CNE, 2012: 12).
- **How many contracts?** The customer-generator should sign two contracts: the first one with a distribution company, which gives him/her accessibility to the grid; and the second one with a commercial company, enabling him/her to buy and sell electricity. As a result, the previous household/grid switch point is no longer valid. Therefore, the customer-generators should apply and pay for a new grid interconnection. The PV sector called for uniform contract models.
- **Conditions for grid interconnection**. Promoters should apply to distribution companies for authorization regardless the capacity of their project, even if the capacity of the future installation is not greater than the demand load. In this latter case, there is no doubt the rule is excessive: a mere notification should suffice. If the power of the on-site facility is greater than the grid capacity available, the consumer-generator must pay for all the network reinforcement (deep connection charging rule). Furthermore, by the RD 1699/2011 distribution companies can reject proposals whether other projects have been already committed. Unfortunately, there is no clear-cut definition of such cases, as well as registered and public information about. Once the PV-DSG plant has been connected the distribution firm will do a first verification of its performance which should be repeated at least every 3 years.[33] The facility owners will be charged for it. In fact, the distribution company can check out the on-site system at will and immediately disconnect it in case of risk evidence. If there is a suspicion of grid trouble caused by the installation, the distribution company will inform the customer-generator in order to check it out. The on-site facility will be reconnected at the moment the distribution company considers is safe. Conflicts will be solved by the administration, but there is no economic compensation for the consumer-generator in case of false alarm. Finally, consumer-generators with >5 kW are obliged to have a 3-wire phase supply point, traditionally though this has not been required up until 15 kW. This change will represent a cost for customer-generators.
- **What about solar gardens?** The RD 1699/2011 allows on-site installations to be owned by the residents (or part of them) of a given apartment block or the houses of a same neighborhood, but solar gardens (that is, generation facilities not physically linked to consumption points) are not allowed (CNE, 2012: 18). This also impedes the promotion of third-party installations by commercial centers, managers of industrial areas, etc.Neither this decree nor the draft indicates how to create and manage such communities. It is only pointed out that the generation capacity will be no greater than the shareholders' consumption load.

[33] Prior the RD 1699/2011 all generation plant had to be officially revised every 5 years.

- **Neither FITs and premiums nor other economic incentives**. PV-DSG cannot take advantage from FITs and premiums, but some other incentives could be set down. The PV sector claimed for subsidies and other advantages almost from the beginning.
- **Mandatory guarantee**. According to the RD 1699/2011 investors on projects from >10 kW to 100 kW should provide a guarantee of 20 €/kW. Projects with a nominal power ≤10 kW are excluded.

5. Comparing and Scoring the Features of the Spain's PV-DSG Draft Regulation

Having reviewed the most important features of the decree draft, the remuneration rules it contains will be modelled according to the model developed above. Its qualities, both general and technical, will be also scored for comparing purposes.

5.1. *The Economic Framework*

The decree draft is focused in promoting self-consumption while simultaneously preventing new financial burdens on the electric system (it succeeds in this goal as it is confirmed in CNE, 2012: 46-51). Thus, exports are banked and act as a cap for imports. Different charges, taxes and fees shape both exports and imports.
The condition of banking can be written as,

$$X_t - \sum_{i=1}^{i=12} M_{t+i} \geq 0$$

being M_{t+i} the imports as compensation. As it can be observed, exports settle the maximum volume to be imported.
Given expression [3], then in every billing period:

- The customer-generator will pay the charges and taxes associated to the volume of exported energy, that is, $x_t = X_t(\gamma_t + \tau_t)$.
- He/she will pay the price, charges and fees associated to the imports, that is, $m_t = M_t(f_t + \lambda_t)$.

where (γ_t) is the generation access charge, (τ) the generation turnover tax[34], (f_t) the fee for metering service and (λ_t) the access charge. Besides imports as compensation, there are extra imports, which are paid for at a price (ε_t) freely negotiate between the customer-generator and the commercialisation company. On the basis of these elements, Table 6 compares the economic streams in the case of a current ratepayer, those faced by a customer-generator under the requirements of the decree and those of an alternative, which has same policy effects but operates more easily. For the sake of simplicity, the economic variables are expressed in constant annual values.

The current ratepayer pays the electricity consumed from the grid at the retail price. Customer-generators operate under the following conditions:

- The energy consumed is the sum of the electricity coming from the customer-generator's own plant, the electricity exported and the extra imports: $q_t = q^*_t + X_t + M^*_t$.
- The term (a) indicates the cost of self-generation. These kWh also pay for the access charge.
- The volume of exports is not greater than the amount imported during the next 12 months, according to the compensation rule. These energy streams imply the payment of different charges and fees (including the generation tax not present in the draft but recently approved).

[34] This tax was established in December 2012. In case of consumer-generators, it is assumed that the tax is applied only on the value of the electricity exported.

- Extra imports (M^*_t) are paid at a price freely negotiated (ε_t).
- Here it has been supposed that exports compensated within the same billing period (a month) do not pay the metering service fee, although this remains an open question in the draft.

Table 6. Comparing the economic features of the decree draft PV-DSG

The current ratepayer	The draft	The alternative
$q_t \cdot w_t$	$q^*_t(a+\lambda_t)$ $X_t(a+\gamma_t+\tau_t)$ $M_t(f_t+\lambda_t)$ $X_t \geq M_t$ $M^*_t \cdot \varepsilon_t$	$q^*_t(a+\lambda_t)$ $X_t(a+\gamma_t+\tau_t+\lambda_t)$

Source: Own elaboration

The alternative is to transform the draft scheme, which is a sophisticated variant of the net billing option, into another one closer to net metering. This variant would require two meters, each one respectively gauging the incoming or exiting electricity. The customer-generator would then pay the associated charges and taxes by billing periods. The metering service would probably be no longer necessary. Furthermore, this proposal would not have damaging effects on the accounts of the electricity system.

Returning to the draft, it can be concluded that the most important variables are the cost of self-generation (a) and the access charge (λ_t). Actually, consumers-generators would probably adjust the on-site system capacity as much as possible to the own demand, given the $Q \leq \Theta$ condition and the cap of 100 kW. Moreover, most exports would be compensated within the billing period, so the inter-month volume could be relatively small. At the same time, the impact of the extra imports could be also considered small, because its price would probably be close to the wholesale market rate. Finally, both the generation access charge (γ_t) and the metering service fee (f_t) are set at a very small value. Perhaps only the recently implemented generation tax (τ_t) may have some economic influence. As a conclusion, both the cost of self-generator and the access charge became the key economic factors of the regulation draft. However, this proposal was issued when Spain's PV generation has reached retail grid parity (Lettner and Auer, 2012).[35] Therefore, the net metering scheme, which does not require FITs, seems an interesting alternative because it is easier both to implement and for promoters to understand. In its first steps it could as well be accompanied by investment subsidies or other incentives.

Whatever may be the interest of discussing the economic features of the draft, it unfortunately seems that the PV-DSG regulation in Spain has not a very bright future for the following reasons:

- From 2008 to 2012, the Spain's electricity demand dropped by 4.42%, whereas from 2000 to 2008 it had increased by 35.99%. The expectations for the next years are also pessimistic. As it is well known, from the point of view of utilities, demand-side generation is a zero-sum game: what consumer-generators gain, utilities lose. Although utilities can expand their activities offering energy services to on-site generators, it could be hard to change their internal routines and move beyond their core business. In any case, the increasing amount of RES-E in the generation mix will require both a new policy and a regulatory framework. There will be included new issues such as the implementation of a new access charges' scheme or the emergence of new business models.

[35] That means that the self-generation cost is lower than €0.22 per kWh (all included), that is, the electricity price for ratepayers with a demand load below 10 kW.

- The rapid growth of electricity demand, especially during the first half of the last decade, put generators under pressure. As a result, the number of installations grew disproportionately, mostly NGCC and RES-E. Today there is a huge excess of generation power in Spain: there are around 106 GW installed but in peak hours only 50 GW are used.
- The deep crisis in Spain has reduced the income of individuals and families. Moreover, in an uncertain labor market, coupled with credit restrictions, it will be difficult to find financial resources to invest in personal projects as PV-DSG.
- Spain gave priority to the ground-mounted installations and, since 2009, also to commercial BIPV. But there are no roof-mounted residential arrays. Therefore, there is no experience in such type of installations and, what is also important, most of urban legislation is yet to be developed. The Spanish situation is very different from that in Germany, where most PV plants are of the rooftop type. While in this country on-site generation could drive PV investments in a few years, the expectations in Spain are pessimistic. As a consequence, the almost exclusive way for recovering Spain's PV sector is MW-size plants nowadays promoted in the best irradiation areas. However, the economic viability of these projects, which output would be directly sold in the pool, is unclear and, moreover, they would be determined by the fiscal measures shaping the energy sector which, as explained above, experienced an acute financial crisis.

5.2. *Scoring Qualities*

The next paragraphs score the draft proposal for comparing purposes. Unfortunately, there is no universal method for comparing the different PV-DSG regulations, or at least the author is not aware of any. For this reason, the method applied here is the IREC (2011) scheme, which has been used for scoring and comparing US state-level policies. This metrics has two steps:

- The first involves numerical values in order to quantify the different features of PV-DSG regulations.
- The second transforms the score into a letter indicating the global rank of policies.

The different elements characterizing on-site promotion programmes are grouped into two sets: those related to the general requirements that should be fulfilled by PV-DSG adherents (or policy points), and those referred to the administrative process to comply and the technical rules to be met by customer-generators (or interconnection procedures). See Table 7 which shows the scoring of the policy points.

Spain's proposal merits a low B grade (from 9 to <15 points). This is the same score as those of Arkansas, Iowa and Virginia (16th position over 26) (IREC, 2011: 86-87). This level is interpreted as follows (IREC, 2011: 25): "Generally good net metering policies with full retail credit, but there could be certain fees or costs that detract from full retail equivalent value. There may be some obstacles to net metering".

The evaluation of interconnection procedures is more difficult because of the lack of technical requirements in the decree draft, although the RD 1110/2007 and especially the RD 1699/2011 contain most of them. Table 8 shows the results of a tentative evaluation of interconnection procedures.

In this case, the score achieved by Spain's proposal is also the B grade (from 9 to <15 points). This is the same score as that of Maryland, North Carolina, South Dakota and West Virginia (10th position over 21). Other states such as Colorado, Connecticut, Indiana, Nevada or New Mexico are also close (IREC, 2011: 88). This level is literally interpreted as follows (IREC, 2011: 25): "Good interconnection rules that incorporate many best practices adopted by states. Few or no customers will be blocked by interconnection barriers. There may be some defects in the standards, such as lack of standardized interconnection agreements and expedited interconnection to networks".

It should be pointed out that it has been just a first attempt to compare different policy's requirement and interconnection procedures for PV-DSG. On the one hand, there are a few features which cannot be applied and the scoring scale does not match very well the options and singularities of the Spain's case. On the other, some criteria should be slightly reinterpreted. As a consequence, results have to be taken with certain caution. There is no doubt that it is crucial to develop a universal scoring metrics for on-site generation regulations.

Table 7. Scoring general requirements

Policy points	Valuation	Comments
Individual system capacity	1	Not greater than 100 kW
Total program capacity limits	2.5	No limits
Restrictions on rollover	-1	This score does not exist in the original scale. But it holds an intermediate position amongst the 0 points given to the "monthly rollover at retail price for one year, excess energy donated to utility annually", and the -2 points to a "monthly payment at wholesale rate of avoided cost" (RMI, 2012: 13).
Metering issues	0	Dual registers or meters purchased or rented by the consumer-generator
Renewable energy credit ownership	n. a.	-
Eligible technologies	1	Solar, wind and other RES-E allowed
Eligible customers	2	No eligible class restriction
Bonus for aggregate net metering	1	Spain's draft allows grouping installations of the same technology located in contiguous properties and sharing a single interconnection point[36]
Bonus for retail choice	0.5	On-site generation is allowed under retail choice
Bonus for community sharing renewable utility	0	Customers unable to host an on-site generation system are not allowed to invest in an off-site facility
Safe harbor provisions, standby charges, or other fees	0	Notaddressed
Policy coverage	1	Rules apply to all utilities
Third-party model	1	Customer signing a long-term contract with a third-party who installs and owns the PV-DSG system is not precluded
TOTAL	**9**	**Low B grade**

n. a. = not applicable

6. Conclusions

At the time of writing this paper (March 2013), despite legal terms and political promises, Spain's regulation of PV-DSG is still pending. It is by now delayed for twelve months and the expectations are unclear. Some people think that a decree regulating the customer's side generation will be enacted along the first semester of 2013, but others are completely pessimistic about it. Anyway, on the one hand, there is no doubt that the regulation draft has been designed to fit the big financial problems of the electricity system and, on the other, the framework does not seem able to boost the investment in PV-DSG. The proposal mostly discourages the potential customers-generators because capacity is capped at 100 kW, there are multiple fees and taxes and there is a lack of specific incentives such as preferential interconnection charges. Moreover, the on-site generation is submitted to a permanent

[36] IREC (2011: 15) also included the aggregation of accounts from different meters, each with its own interconnection switch, located in (contiguous) properties belonging to the same owner. Grouping registering values has not been explicitly forbidden by the Spanish draft. This possibility could be freely agreed between the consumer-generator and the distribution company.

control by the distribution companies without any safeguards against abuse. Finally, the temporally limited rolling out of electricity excess could probably disincentive energy savings and efficiency improvements. The main goal of a Spanish PV-DSG regulation would be to remove any regulatory element that could hinder the diffusion of the instantaneous consumption with electricity exchanges.

Table 8. Scoring the interconnection procedures

Policy points: Interconnection procedures	Valuation	Comments
Eligible technologies	0	All customer-sited generators qualify. If a generator fully complies with the relevant technical standards, interconnection could not be denied
Individual system capacity	-4	Less than 500 kW: maximum 100 kW
Breakpoints for interconnection process	-1	Two levels: there is a simplified interconnection procedures for generators with a capacity ≤10 kW.
Timelines	1	Timelines are shorter than the general case, especially if capacity ≤10 kW
Interconnection charges	0	Interconnection charges are the same as the general charges already existing
Engineering charges	1	Engineering fees are fixed. There is no cost for the interconnection study, but there is a financial guarantee
External disconnect switch	1	Redundant external disconnect switch is not required
Certification	0	General standards are applied
Technical screens	0	General standards' screens are applied
Network interconnection	0	The interconnection capacity is limited by the network available power. The deep connection charging rule is applied
Standard form agreement	1.5	Standard agreement with friendly clauses and simplified form for systems under 10 kW
Insurance requirements	1	No additional insurance is required
Dispute resolution	2	Process in place with no cost and quick
Rule coverage	1	Rules apply to all utilities
Adverse system impact check required	-1	Compulsoryfirst operational check of the installation by the distribution firm. The owner pays for it
Extra points added to score (1)	7.5	-
TOTAL	**10**	**Low B grade**

(1) According to IREC (2011: 21) 7.5 points are added to interconnection scores to achieve grading parity with policy scoring

Annex. The Financial Costs of FITs

Let's analyze the following table regarding the accumulated costs of a FITs policy.

Year	Annual generation (q_t) (MWH)	Accumulated costs of FIT support (monetary units) (v_t)
0	q_0	$v_0=p_0\cdot q_0$
1	q_0+q_1	$v_1=p_0\cdot q_0\cdot(1+\varepsilon)+p_0\cdot q_1\cdot(1-\delta)=v_0\cdot(1+\varepsilon)+p_0\cdot q_1\cdot(1-\delta)$
2	$q_0+q_1+q_2$	$v_2=p_0\cdot q_0\cdot(1+\varepsilon)^2+p_0\cdot q_1\cdot(1-\delta)\cdot(1+\varepsilon)+p_0\cdot q_2\cdot(1-\delta)^2=$ $=v_1\cdot(1+\varepsilon)+p_0\cdot q_2\cdot(1-\delta)^2$
3	$q_0+q_1+q_2+q_3$	$v_3=p_0\cdot q_0\cdot(1+\varepsilon)^3+p_0\cdot q_1\cdot(1-\delta)\cdot(1+\varepsilon)^2+p_0\cdot q_2\cdot(1-\delta)^2\cdot(1+\varepsilon)+p_0\cdot q_3\cdot(1-\delta)^3=$ $=v_2\cdot(1+\varepsilon)+p_0\cdot q_3(1-\delta)^3$
... and so on.		

Source: Own elaboration

In the first year, each PV MWH (q_0) is sold at tariff p_0. In the following year, the operating plants will sell their production at the same tariff but increased by ε, while new installations will receive the initial tariff, reduced δ times. Of course, this partially reduced tariff will grow at the ε rate from then onwards. Thus, the regular pattern over time shown by ε and δ can be studied defining a recurrence expression: in the year $t=t^*$, the accumulated amount of financial duties (v_t) is given by,

$$v_t = v_{t-1}(1+\varepsilon) + p_0 q_0 (1-\delta)^{t^*}$$

If it is added the $q_t=q_0=q$ assumption, this series increases at a fixed rate because every year the same amount of MWH enters the generation mix. Therefore,

$$v_t = p_0 q \sum_{t=0}^{t=t^*} (1-\delta)^t (1+\varepsilon)^{t^*-t}$$

This series can be aggregated,

$$v_t = p_0 q \left[\frac{(1+\varepsilon)^{t^*+1} - (1-\delta)^{t^*+1}}{\varepsilon+\delta} \right]$$

If $t^*=T$ is a high number and $\frac{1-\delta}{1+\varepsilon} \neq 1$, then (1-$\delta$) could be ignored. Hence, the expression of the total amount of financial costs (v_T) becomes,

$$v_T = p_0 q \frac{(1+\varepsilon)^{T+1}}{\varepsilon+\delta}$$

As it is obvious, instead of the whole value of the preferential tariffs, it is more realistic to consider the difference between them and the wholesale market prices of electricity (under the assumptions that there are only grid-connected PV plants and that consumers pay the promotion policy). Applying such criterion, the OGC becomes what could be called the Real Gross Costs (RGC). Furthermore, there is another shortcoming in the table: the OGC (or the RGC) are not the net cost of the promotion policy. Actually, the gross worth of its financial burden should be reduced by the three following factors:

- The amount of the reduced imports of energy, mainly fossil fuels.
- The value of the less environmental negative externalities because of the lower emissions of greenhouse gases.
- An estimation of the impact of PV kWh on the wholesale prices of electricity.

If these impacts are taken into account, the OGC (or, the RGC) becomes what can be considered as the Net Real Costs (NRC) of the FIT policy.

Returning to the v_T expression, its value depends on three factors (δ, ε, and q) provided that p_0 and T are given. The following linear approach is suggested in order to identify their degree of impact:

$$v_T \approx v_T(q_0,\varepsilon_0,\delta_0)+\frac{\partial v_T}{\partial q}(q_0,\varepsilon_0,\delta_0)(q-q_0)+\frac{\partial v_T}{\partial \varepsilon}(q_0,\varepsilon_0,\delta_0)(\varepsilon-\varepsilon_0)+\frac{\partial v_T}{\partial \delta}(q_0,\varepsilon_0,\delta_0)(\delta-\delta_0)$$

where dq, $d\varepsilon$ and $d\delta$ represents small changes in the selected variables. From the expression of $v_T$the following derivatives can be obtained,

$$\frac{\partial v_T}{\partial q} = p_0\frac{(1+\varepsilon)^{T+1}}{\varepsilon+\delta}$$

$$\frac{\partial v_T}{\partial \varepsilon} = p_0 q(1+\varepsilon)^T\,\frac{T(\varepsilon+\delta)+\delta-1}{(\varepsilon+\delta)^2}$$

$$\frac{\partial v_T}{\partial \delta} = -p_0 q\frac{(1+\varepsilon)^{T+1}}{(\varepsilon+\delta)^2}$$

The range of feasible values for the aforementioned variables is constrained by economic and technological reasons. Let's assume the following common values of the PV sector: q=1,500 GWH (approximately, 1,000 MW of additional capacity), ε=0.02, δ=0.05 and T=30. Then, the expression to be considered is,

$$dv_T \approx 26.394dq+637.663d\varepsilon-565.588d\delta.$$

Therefore, *ceteris paribus*,

- A 10% increase of q, that is, from 1,500 to 1,650 GWH (dq=150) gives rise to a dv_T=3,959 monetary units.
- If ε rises from 0.02 to 0.022, $d\varepsilon$=0.1, v_T increases by 1,310 monetary units.
- If $d\delta$=0.1, that is, δ=0.055, v_T is reduced by -2,639 monetary units.

These results suggest that the OGC dynamics of a FIT depends mostly on the annual addition of solar generation capacity. Hence, capping q is the best option to control the increase in OGC. The second one is to accelerate the reduction rate of tariffs ($\Delta\delta$). These cost-containment measures reduces the amount to be paid by consumers or taxpayers, while ensuring a sufficient and appropriate revenue for producers, although it might be in conflict with the achievement of RES-E targets. More information and an application of this model can be found in Mir (2012: 314-325, 330-338 and 375-381).

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Publication March, 2013