DIRECTORATE GENERAL FOR NEIGHBOURHOOD AND ENLARGEMENT NEGOTIATIONS – DG NEAR

Short Term High Quality Studies to Support Activities under the Eastern Partnership

HiQSTEP PROJECT

STUDY ON THE EFFECT OF THE PLACEMENT OF SOLAR PANELS ON BUILDINGS TO INCREASE ENERGY SECURITY AND ENERGY EFFICIENCY AND DEVELOP CLEAN ENERGY IN THE EASTERN PARTNERSHIP COUNTRIES

Component 1 Report:

Review of the EU Experience with Building-PVs

July 2017

This report has been prepared by the KANTOR Management Consultants Consortium. The findings, conclusions and interpretations expressed in this document are those of the Consortium alone and should in no way be taken to reflect the policies or opinions of the European Commission

List of abbreviations

AM	Armenia
ANRE	The National Regulatory Authority for Energy in Moldova
AREA	Azerbaijan State Agency on Alternative and Renewable Energy Sources
AZ	Azerbaijan
BY	Belarus
CBA	Cost Benefit Analysis
CEER	Council of European Energy Regulators
DGPV	Distributed Generation from Photovoltaics
EaP	Eastern Partnership
EC	European Commission
ECT	Energy Community Treaty
EU	European Union
EUD	EU Delegation
GE	Georgia
GEDF	Georgian Energy Development Fund
GWNERC	Georgian Water and Energy Regulatory Commission
HiQSTEP	Short term high quality studies to support activities under the Eastern Partnership
MD	Moldova
NEURC	National Energy and Utilities Regulatory Commission of Ukraine
PSRC	Public Services Regulatory Commission of the Republic of Armenia
PV	Photovoltaic(s)
R2E2	Armenia Renewable Resources and Energy Efficiency Fund
RES	Renewable Energy Sources
SAEEE	State Agency on Energy Efficiency and Energy Saving of Ukraine
STL	Study Team Leader
T&D	Transmission and Distribution
TOR	Terms of Reference
UA	Ukraine
MS	Member State
SPE	Solar Power Europe
ROO	Renewable Obligation Order

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Preamble

The present report is a deliverable of the “Study of the Effect of the Placement of Solar PV on Buildings in the EaP Countries” carried in the framework of the EU-funded project “High Quality Studies to Support Activities under the Eastern Partnership - HiQSTEP” (EuropeAid/132574/C/SER/Multi). The study covers all six Eastern Partner Countries, namely Armenia, Azerbaijan, Belarus, Georgia, Moldova and Ukraine.

The overall objective of the study is to address the effect of the placement of solar panels on buildings in Eastern Partner countries for the purpose of increasing energy security and energy efficiency and developing clean energy sources.

The specific objectives of the study are the following:

To present EU policies, rules, regulations, tools and schemes towards the promotion of solar panels on buildings;

To assess existing policies, rules, regulations and tools towards promotion of solar panels on buildings in the six Eastern Partner countries;

To develop cost-benefit analysis for the staged development of building PVs in all Eastern Partner countries;

To formulate recommendations on how to enhance PV penetration in the six Eastern Partners;

To quantify the impact of building PV penetration to the overall energy mix and on the energy security of each country and to quantify the impact of PV generated energy to greenhouse gas emission reduction.

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1 Introduction

As the deliverable of the first component of the study the present report comprises a review of EU practices in respect of buildings' solar PV technology and its application in the EU Member States (MS). More specifically, the report briefly discusses EU policies supporting Renewable Energy Sources (RES) in general and provides an overview of solar PV technology. Furthermore it discusses the essential features of the legal and regulatory environment within which the EU has reached its current penetration levels of solar PV in buildings as well as the impact of this deployment to the electricity system. The report also reviews specific national implementation case studies in respect of their legal and regulatory framework as well as in regards of specific pilot programmes and their respective lessons learnt. Lastly it provides recommendations for the proper design of a programme to promote building-PVs. The conclusions of the report will be used to formulate the templates of the National Reports that will be used to collect relevant information regarding the Eastern Partner Countries foreseen in component two of the study and feed the work of component four and five of this study concerning the design of building-PV promotion programmes.

1.1 PV deployment in the EU

The penetration of PV technology in the European electrical energy mix has reached today's high shares through a long, and not always easy and successful, path. During the last two decades of the 20th century, the main driver for the early deployment of the "exotic" at that time, yet promising, technology, was the industrial policy of pioneering EU Member States (MS), like Germany. Nevertheless, the accelerated development of PVs in the last ten years was the result of intensive R&D and market support efforts as a part of the EU energy and climate policy, as it was in particular transposed into various national schemes and programs. The growth of PV deployment in various MS is depicted in Figure 1 below. According to the latest data from EurObserver[1] the total installed PV capacity in the EU28 reached 94.6 GW in 2015 (97.1 GW according to the Solar Power Europe 2016 Outlook[2]), producing slightly over 100 TWh of electricity. While PVs used to play a rather insignificant role in the 2000 electrical generation mix, they currently represent over one third of total RES capacity in the EU, having already exceeded the 2020 targeted deployment levels at EU level[3].

Having demonstrated a continuous annual growth for over a decade, the annual installed capacity of PVs in the EU is declining after peaking up to a maximum of 22 GW in 2011 (see Figure 2). The slight increase in 2015 is expected to be followed by a new decrease in 2016, according to SPE 2016 Global Outlook. This decline largely depicts changes in support policies, often coupled with retroactive measures as in Spain and Greece. Such actions stemmed by the need to reduce electricity costs for final consumers by means of reducing the, often ungrudgingly offered in the past, incentives mainly in form of price subsidies.

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[1] http://www.eurobserv-er.org/photovoltaic-barometer-2016/

[2] http://www.solarpowereurope.org/insights/global-market-outllook/

[3] EC, COM(2015) 293 final, Renewable energy progress report, http://eurlex.europa.eu/resource.html?uri=cellar:4f8722ce-1347-11e5-8817-1aa75ed71a1.0001.02/DOC_1&format=PDF

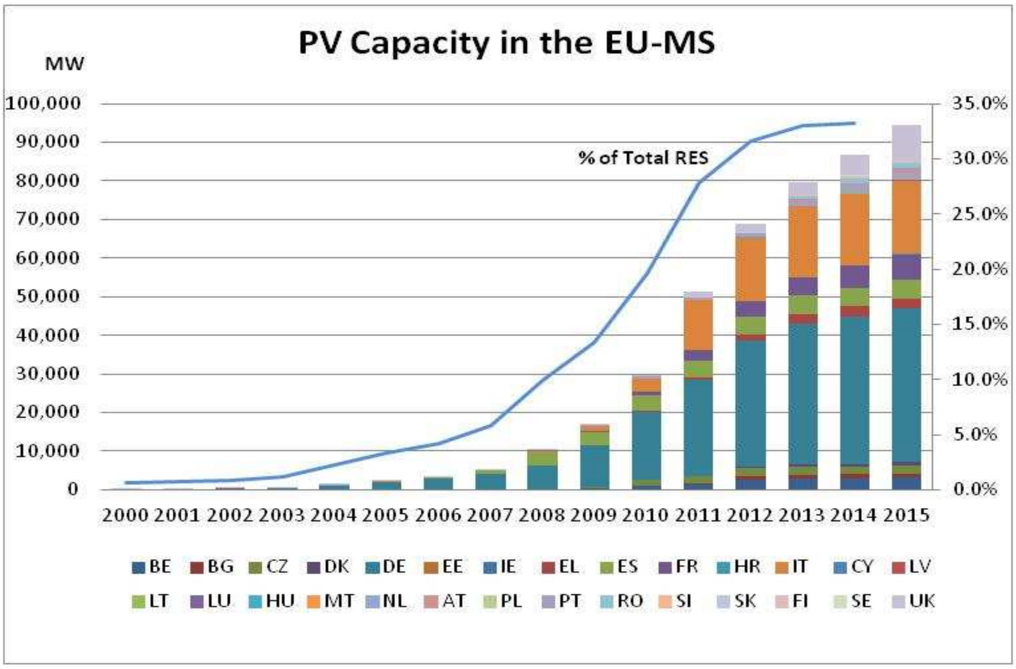


Figure 1: Development of PV capacity in EU-MS (Data: 2000- 2014 Eurostat, 2015 EurObserver)

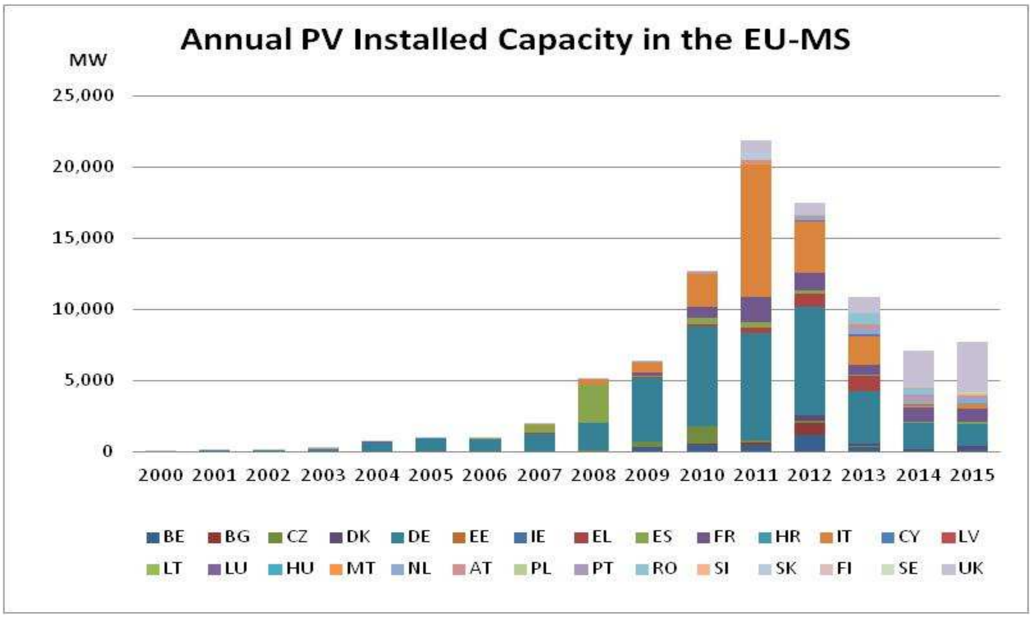


Figure 2: Annual PV installed capacity in the EU-MS (Source: 2000- 2014 Eurostat, 2015 EurObserver)

It is noteworthy that the geographical distribution of PV installed capacity does not line up with the "maximum irradiation" logic. With the exception of Italy, Greece and Malta total installed capacity per inhabitant is greater in central and northern MS (see Figure 3&4), highlighting the importance of non-technical aspects that influence the deployment of the technology, such as support policies and financial incentives, overall economic conditions, public awareness, etc.

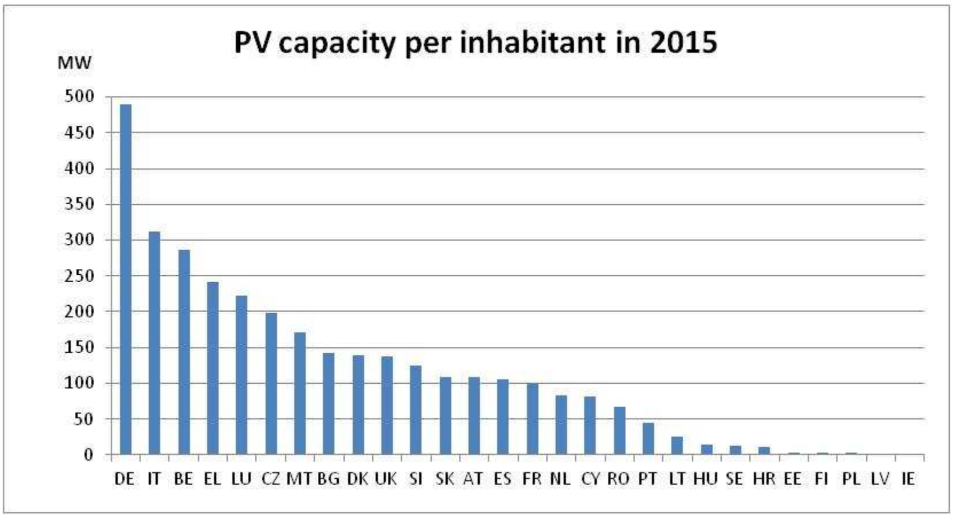


Figure 3: PV capacity per inhabitant (Wp/inh.) in the EU-MS in 2015 (Eurobserver, Photovoltaic Barometer 2016[4])

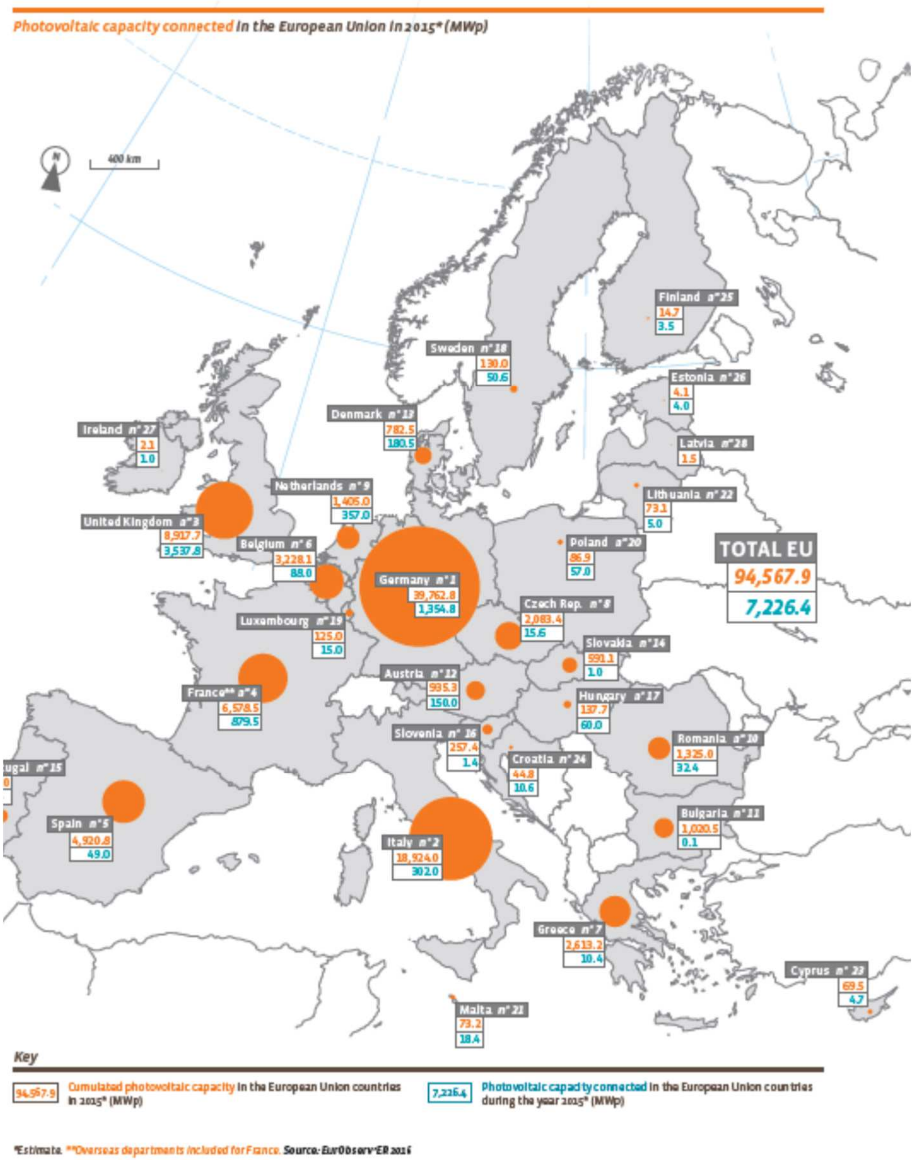


Figure 4: Grid connected PV capacity in the EU in 2015 (Eurobserver, Photovoltaic Barometer 2016[5])

[4] http://www.eurobserv-er.org/photovoltaic-barometer-2016/

[5] http://www.eurobserv-er.org/photovoltaic-barometer-2016/

The segmentation of PV installations illustrated in Figure 5 below, provides an overview of the different approaches of MS towards PV deployment. Although the categorisation merely refers to the capacity segmentation, rather than the actual distinction between the referred categories (see reference note no.6), residential (merely rooftop) PV systems constitute a small portion of total installed capacity in most MS where large deployment of the technology has occurred (e.g. Spain, Germany and Greece) indicating the existence of a favourable framework for large scale installations. On the other hand, smaller and more densely populated MS like the Netherlands, Denmark, Belgium and Austria have targeted mainly small-scale building-PV systems with quite remarkable results.

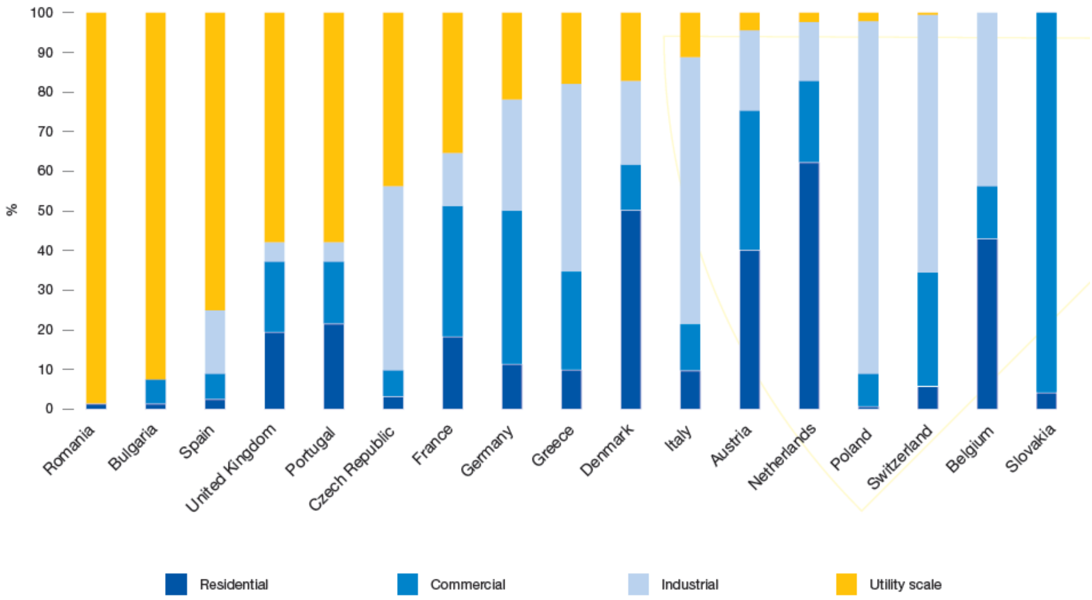


Figure 5: EU PV cumulative capacity segmentation in 2014 (SPE, Global Market Outlook 2016[6])

1.2 Support schemes for PV deployment in the EU

The aforementioned development of PVs in the EU is the consequence of some thirty years of policies and programmes that supported the commercialisation of the technology in its early phase of development and the consequent uptake, as the technology was becoming more cost effective. Pioneer MS like Germany that initiated PV support schemes already from the mid '80s, mainly as a measure of a visionary industrial policy, largely reaped the profits of the globalisation of a market that was once the privilege of the most advanced economies, like Japan and the US.

1.2.1 Current trends

According to the most recent CEER's report on the status of RES support schemes[7] most MS have adopted a feed in tariff scheme (FiT) as a measure to support electricity produced by RES. Figure 6

[6] Note: The categorisation is as follows: residential-systems below or equal to 10 kWp, commercial- systems with a capacity between 10 and 250 kWp, industrial- systems with a capacity above 250 kWp, utility scale- systems with a capacity above 1000 kWp and built on the ground

[7] CEER, Status Review of Renewables and Energy Efficiency Support Schemes in Europe in 2012 and 2013, January 2015, C14-SDE-44-03
http://www.ceer.eu/portal/page/portal/EER_HOME/EER_PUBLICATIONS/CEER_PAPERS/Electricity/Tab4/C14-SDE-44-03_Status%20Review%20on%20RES%20Support%20Schemes_15-Jan-2015.pdf

provides an overview of the average support in €/MWh for electricity produced by PVs in a number of MS in 2013. The support ranges from as high as ca.450€/MWh in the Czech Republic to nearly 11€/MWh in Estonia, depicting the differences in approaches and priorities in the MS. It is worth noticing that FiTs used to be even higher than the average annual figures (e.g. in Greece rooftop PV FiT was 550€/MWh at the time). Notably some MS (DK, IE, FI) do not provide any kind of support for PV electricity, according to the report. It should be noted that the height of support refers to the average support of all installations hence it includes old contracts with high tariffs as well as new ones with reduced support.

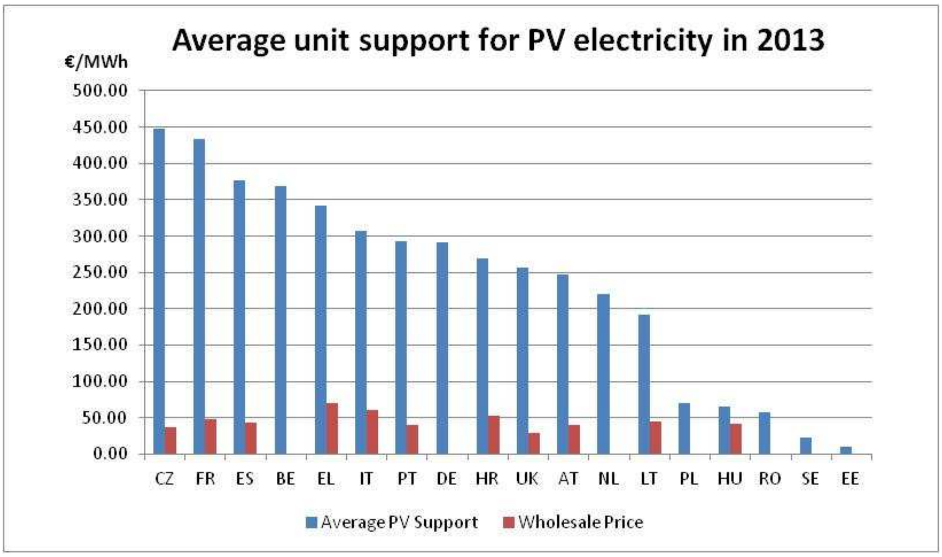


Figure 6 Average unit support for PV electricity in 2013 (CEER, Status Review of Renewables and Energy Efficiency Support Schemes in Europe in 2012 and 2013, January 2015, C14-SDE-44-03)

The publication of the “Guidelines on State aid for environmental protection and energy 2014-2020[8]” by the EC introduced major changes for the support of electricity from RES, aiming at integrating RES in the electricity market and minimizing the cost of the aid by introducing mandatory competitive mechanisms as of 2017. In this new framework FiTs are no longer an allowed support scheme for new installations and shall be substituted by either Feed in Premiums (FiP) supplementing the market price or by a quota mechanism. However, even under this new framework, small-scale installations up to 500kW may be exempted from the general rules and it is hence still allowed to support them by means of FiT.

Consequently, many MS have changed the support framework for RES incorporating the new rules. As of today, several support schemes have been approved by the EC, most adopting FiP coupled with auctions. The following table presents information on current support for PVs in MS with approved schemes.

Member State	PV Category	Main Support Scheme
Germany	P<100kW	FiT
	P>100kW	Auction based FiP
Greece	Rooftop PV (P<10kW)	FiT or Net Metering
	Gr. Mounted (P<500kW)	Eligible for FiT, FiP or Net Metering
	Gr. Mounted (P>500kW)	Auction based FiP as of 2016
IT	P<500kW	Net metering
UK	P<50kW	FiT

[8] http://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:52014XC0628(01)&from=EN

	50kW<P<5MW	ROO or FiT
	P>5MW	CfD
PT	P<500kW	FiT
	P>500kW	Tender based FiP

Table 1: Support schemes for PV installations in selected MS (various sources)

2 Building - PVs

In this chapter a brief description of the technical and economic aspects of building-PV systems is given. Issues regarding grid connection, legal and regulatory specificities, and the new opportunities arising with storage systems are also presented. Finally, a discussion of the main features of the decision-making process for installing PV systems on buildings is provided giving useful insights for efficient support policy design.

2.1 A quick overview of PV technology

A PV system consists of the PV modules (array of cells generating the electricity) and the balance-of-system (BOS). Depending on the size of the system an appropriate number of PV modules are electrically connected forming an array of modules. PV modules that are connected in series form PV strings that are then connected in parallel via string boxes to the BOS. The BOS generally includes, apart from the necessary cabling, batteries (if applicable), charge controller, dc/ac inverter and other components based on the systems configuration. The following Figure 7 provides an indicative layout of a PV system.

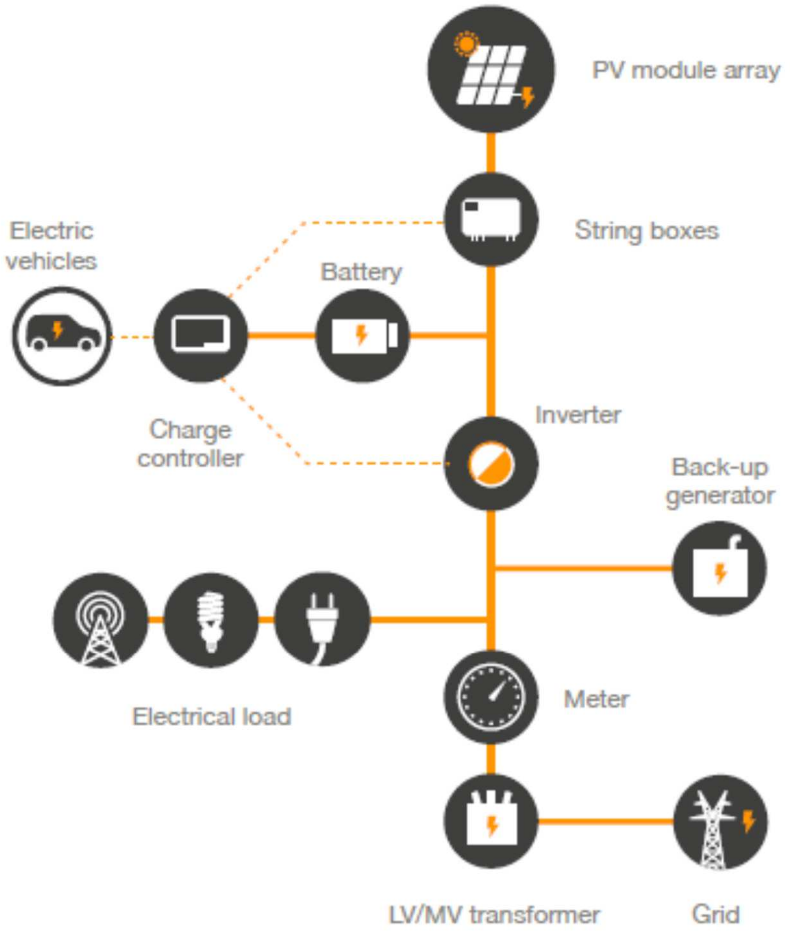


Figure 7: An indicative layout of a solar PV system (Source: ARUP, Five minute guide: Rooftop Solar PV[9])

[9] http://publications.arup.com/publications/f/five_minute_guide_to_rooftop_solar_pv

Most systems are so-called "flat-plate", i.e. collecting solar energy directly on the module. Flat-plate systems are usually static with a fixed orientation, but sun tracking may also be used. A distinctly different type of system, Concentrating PVs (CPVs), uses an optical system in combination with sun tracking to concentrate sunlight onto a small, highly-efficient solar cell.

2.1.1 PV module types

Crystalline silicon c-Si is the most popular material used for the construction of solar cells. Polycrystalline modules are widely used, as they are produced by many proven manufacturers around the world. They are typically less expensive than mono-crystalline ones, but are not as efficient. Because of the way they are manufactured, mono crystalline modules have a higher efficiency than most other types of modules, but are also more expensive.

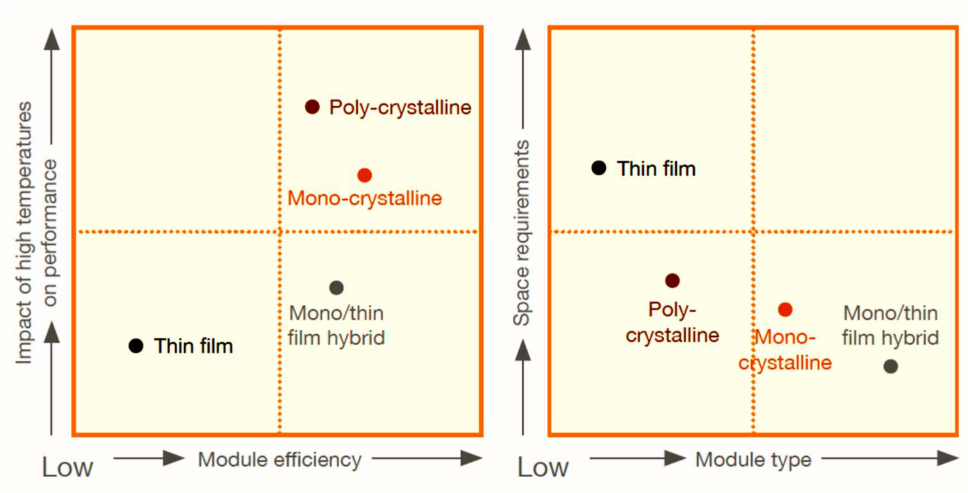


Figure 8: A comparison of PV modules against ambient temperature, efficiency and energy density (Source: ARUP, Five minute guide: Rooftop Solar PV)

Thin film modules are made from a variety of different substrates (typically Copper indium gallium selenide (CIGS), cadmium telluride (CdTe) and amorphous silicon (a-Si)). While their average efficiency (kWh per m^2) is less than both types of crystalline modules, they typically cost less to produce. One of the many R&D efforts in the direction of improving the efficiency of thin film modules is the hybrid thin film module. Its dual layer structure of microcrystalline and amorphous silicon can capture both long and short wavelengths of the light spectrum allowing the hybrid thin film module to convert even more sunlight into electricity. Thin film modules contain heavy metals that need to be disposed in an appropriate environmentally sensitive manner at the end of their useful lifetime. Most thin film manufactures are increasingly favouring CdTe and CIGS modules, with an increasing focus on the utility scale market. Flexible thin film modules (typically a-Si) are generally only used in small-scale applications and are often not easily available for larger projects.

All PV modules' performance decreases as ambient temperatures increase. Thin film modules typically perform better in hot weather, but the impact of high temperatures should be considered into the system design, and accounted for in facility yield analysis. Mono/thin film hybrid modules combine the benefits of both types of modules; the performance under higher temperatures with the efficiency of crystalline modules.

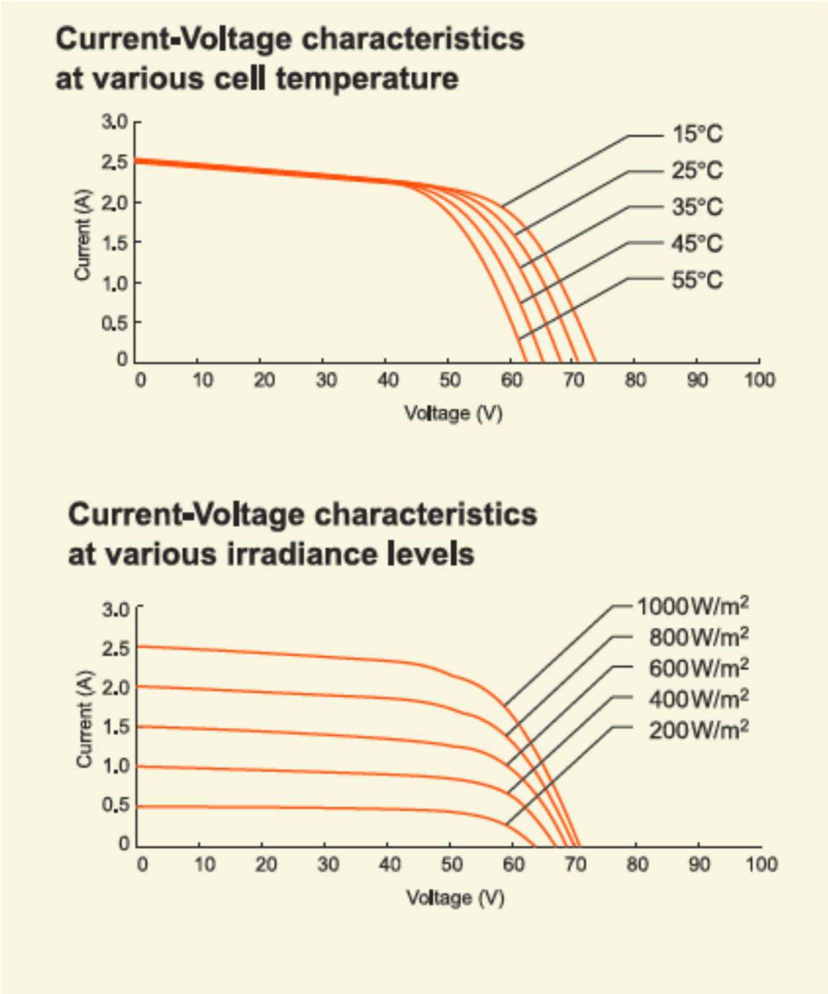


Figure 9: Electrical characteristics of PV cells and their response to temperature and irradiance levels (Source: KANEKA Corporation[10])

The impact of shading on modules needs to be considered as well and one could think the effect of shading as a partial (or complete in some cases - reduction of irradiance. Depending on the module type selected, partial shading of the module can render the whole module ineffective. This in turn results to a reduced performance of the module's string and has an adverse effect on the overall system's performance.

2.1.2 Roof mounting systems

Most building-PVs are installed on buildings' roofs. Different roofs require different mounting solutions and therefore the module mounting system selected depends on the roof type and the structural characteristics of the building. While PV systems add a relatively low additional load on a roof, it is still important to ensure that the overall system is in line with structural allowances, and that it does not compromise the building's weather-proofing.

Systems that track the sun are also available, but these are more common in ground-mounted installations. They typically cost more, are more technically complicated and require additional maintenance (on their moving parts and optical systems).

[10] http://www.kaneka-solar.com/product/thin-film/pdf/U-EA.pdf

It is common that for buildings with an inclined roof, the placement of PV modules follows the existing inclination, with the inevitable subsequent possible loss in the system's efficiency, due to deviations from the optimum inclination and orientation. Optimum inclination (compared to a flat plate) and orientation depends on the latitude the system is installed. The following Figure 10 shows the variation in efficiency of typical PV modules for various orientation and tilt angles in Northern Ireland.

Orientation Chart showing output for different orientation and tilt angles (% of maximum)

Tilt (°)	West									South	East								
	90	80	70	60	50	40	30	20	10	0	10	20	30	40	50	60	70	80	90
0	87	88	90	91	92	92	93	93	93	93	93	93	92	92	91	90	89	87	86
10	84	87	90	92	94	95	95	96	96	97	97	96	95	94	93	91	89	87	84
20	82	85	90	93	94	96	97	98	99	99	98	97	96	95	93	91	88	84	81
30	78	83	87	91	93	96	97	98	99	100	98	97	96	95	93	89	85	81	78
40	75	79	84	87	92	94	95	96	96	96	96	95	94	92	90	86	82	77	72
50	70	74	79	83	87	90	91	93	94	94	94	93	91	88	83	80	76	73	70
60	65	69	73	77	80	83	86	87	87	87	88	87	85	82	78	74	71	67	63
70	59	63	66	70	72	75	78	79	79	79	79	79	78	75	72	68	64	61	56
80	50	56	60	64	66	68	69	70	71	72	72	71	70	67	66	60	57	54	50
90	41	49	54	58	59	60	61	61	63	65	65	63	62	59	60	52	50	47	44

Figure 10: Tilt and orientation efficiency variation chart of Northern Ireland (Source: PV (NI) Ltd[11])

In flat roofs a choice can be made on whether the modules will be placed horizontally or if mounting systems similar to those of the ground-mounted installations will be used. The following figure presents a summary of typical rooftop mounting solutions depending on the roof type.

The key technical considerations pertinent to the selection of the appropriate roof mounting system include:

- Penetrative mounting systems should not compromise the building's waterproofing;
- The building's structural integrity and the roof's load bearing capacity should always be ensured;
- The system's layout should consider local health and safety requirements, including access by emergency services in the event of a fire. Accessibility should also accommodate, system maintenance, cleaning the modules and carrying out maintenance on any of the system components;
- The mounting system should be able to withstand applicable wind and/or snow loading;
- As the mounting system, will be exposed to atmospheric conditions, it is important that the material selected is adequately treated to prevent corrosion.

[11] http://www.pvni-ltd.com/content/solar-pv-northern-ireland

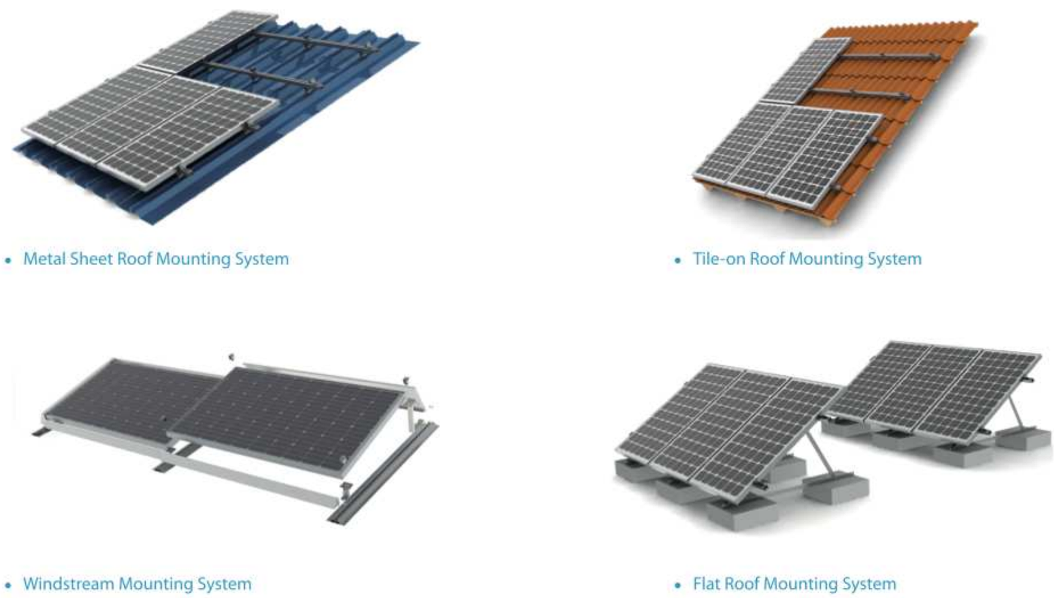


Figure 11: Typical rooftop mounting solutions (Source: Versol Solar[12])

2.1.3 Building integrated PV (BIPV)

PV modules can be incorporated into the building's envelope serving a dual purpose of producing electricity and enhancing the building's aesthetic features, by replacing traditional building materials. Facades and roofs of buildings are the architectural units, which may easily be considered for BIPV. None of them has structural functionality, thus they can be considered as self-supporting construction elements from the architectural point of view. In addition, the overall requirements and functionality of conventional façade and roofing units are not affected by the addition of PVs. In summary, the BIPV opportunities in buildings may follow the taxonomy shown in Figure 12 below:

Facades
- ventilated façade unit
- curtain wall
- shading system unit

Roofs
- skylight unit
- roofing shingle

Figure 12: BIPV taxonomy (Source: BFIRST project[13])

BIPVs can be poly-Si, mono-Si or a-Si, depending on the characteristics/properties of the architectural units that the BIPV are meant to implement or substitute e.g. thin film application is most appropriate where a curved architectural element is considered. Since essentially the technology of the BIPV solar modules is identical to that of the normal PV modules the effects of temperature and irradiance are similar. Near shading from other buildings or trees exists more often particularly in the case of vertical placement of the solar modules e.g. a solar façade. Due to the architectural characteristics of each individual building and the variety of types of BIPV solutions, an

[12] https://www.solarchoice.net.au/blog/versol-solar-mounting-tracking-solutions-for-all-pv-applications/
[13] http://www.bfirst-fp7.eu

energy intensity (i.e. output/space occupied) comparison between rooftop PV and BIPV would generally favour the former.

According to the European Directive 2010/31/EU all new buildings will have to be nearly-zero-energy buildings[14] (NZEBs) by the end of 2020, while new public buildings will have to reach the same goal by as early as the end of 2018. A range of improvements in conceptual, technological and energy-management aspects will be required to transition from the current low energy buildings standards to NZEBs. One key evolution is that NZEBs will effectively need to balance their total energy consumption with an equivalent amount of self-produced renewable energy. As a result, in the near future PVs will be increasingly integrated in buildings at the design stage, as opposed to the roof-retrofit approach, which has predominated until now.

In response, innovative PV products have started to appear, bridging the gap between traditional flat-plate PV modules and building envelope construction materials. These BIPV products will provide innovative means of producing energy for buildings, not only on roofs but also on facades, canopies or even windows, while at the same time bringing aesthetic and multifunctional benefits to designers of NZEBs.

Nevertheless, costs and standardisation and in some cases aesthetical issues comprise still the major barriers for BIPV massive deployment while efficiency, BOS, junction boxes, cell type, wiring management are just part of a long list of details that are so crucial for successful BIPV installations.

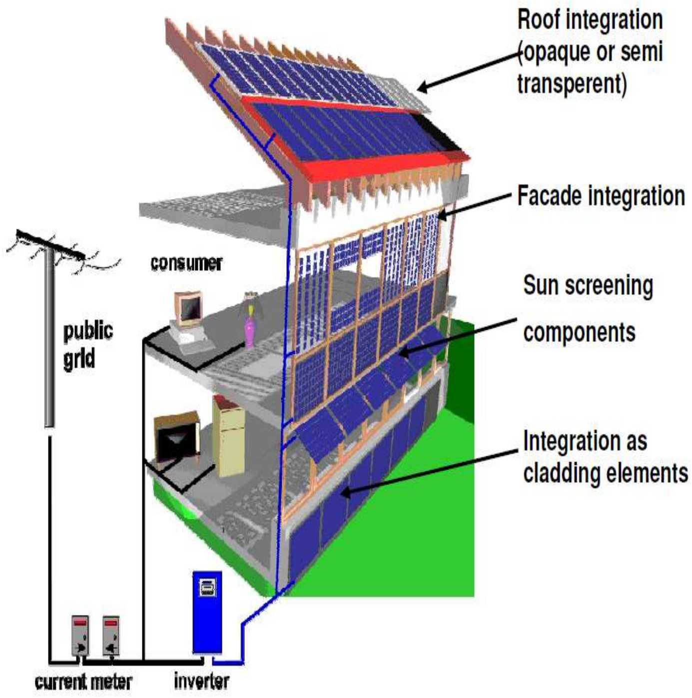


Figure 13: BIPV opportunities (Source: PURE project[15])

Generally, the following considerations may be relevant while designing or planning a renovation of a building and BIPV are among the technology options:

[14]http://ec.europa.eu/energy/en/topics/energy-efficiency/buildings/nearly-zero-energy-buildings
[15] https://ec.europa.eu/energy/intelligent/projects/en/projects/pure

- Engage experts as early as possible in the design process, ideally at the conceptual design stage
- Consider the adverse impact on internal spaces, since solar technologies can lead to increased temperatures;
- Design for access after installation;
- Use “off the shelf” products;
- Consider the suitable façade construction and solar technologies together;

For the highest energy performance, the horizontal or slightly tilted facets of a building are the best: Vertical facades receive less solar energy than horizontal elements of a building and are therefore not ideal.

2.1.4 Inverter and electromechanical equipment

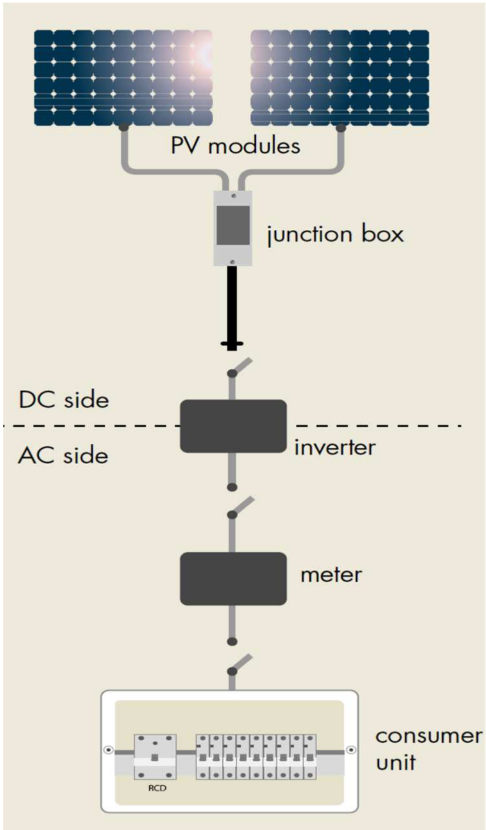


Figure 14: Block diagram of a typical PC installation (Source: IET Wiring Matters, Winter 07, www.theiet.org)

The electrical equipment used in a PV system is important in ensuring that the system operates at an optimal level. Most often PV systems are considered as installations that can notionally be split in their DC and the AC side. This mainly reflects the different characteristics of each side. The inverter is a central component since it connects these two sides i.e. the generation (DC) side and the delivery/consumption (AC) side. A simple block diagram illustrating the aforementioned distinction of DC and AC sides is presented in the schematic on the right. The inverter transforms direct electrical current (DC) generated by the PV system into alternating electrical current (AC). The factors to consider when selecting inverters include compatibility with module technology, compliance with grid code and other applicable regulations, inverter-based layout, reliability, system availability, serviceability, modularity, telemetry requirements, inverter locations, quality and cost. The design of any PV system should consider local standards and regulations, as these would influence the type of inverter that can be used. The size of the inverter, its efficiency rating and the operational and environmental conditions will all influence the performance of the PV system. Single phase or three-phase grid connected or islanded inverters can be used, depending on the overall load requirements. Systems are generally modular and system sizes can typically be easily increased as a result. Solar PV inverters often have a special control capability, called maximum power point tracker (MPPT) which allows them to optimize current and voltage settings in order to maximize the output power.

A key requirement is that the inverter will disconnect the PV system when the distribution system is not energised. This is to prevent the hazardous situation of the photovoltaic system feeding the network or local distribution system during a planned or unscheduled loss of mains. Such an event is termed ‘islanding’ and presents a potential danger to those working on the network/distribution system.

Network operators through the relevant network codes place additional requirements on the PV systems, which are usually imposed at inverter level. In addition to the islanding protection these may also include: a capacity threshold in order to limit three-phase load unbalance in the distribution network, reactive energy and voltage quality requirements such as Total Harmonic Distortion, flicker, etc[16].. Inverters that satisfy those requirements in a local market come with a type test certificate. The following schematic presents a list of PV system components distinguishing between the DC and AC sides. It should be noted that in cases of small-scale installations that are connected directly to the Low Voltage Network the AC side does not involve transformer(s) and substation.

DC Side

- Array(s) of PV modules
- Inverters
- DC cabling (module, string and main cable)
- DC connectors (plugs and sockets)
- Junction boxes/combiners
- Disconnectors/switches
- Protection devices
- Earthing

AC Side

- AC cabling
- Switchgear
- Transformers
- Substation
- Earthing and surge protection
- Metering

Figure 15: An overview of the PV System compoents distinguished to by the DC and AC sides of the system

Cables transmit power from the modules to the string boxes and inverters; and from the inverter to the building internal installations and/or grid. Rooftop cables are typically exposed to the ambient conditions and should therefore be able to withstand UV light, ozone, heat and rain or hail without degrading. Cables used in PV installations are specifically manufactured to be UV-radiation resistant, while the construction of DC cabling is generally different from that of the AC cabling. A similar need has led do the development of different protection and switching equipment since both the critical ratings but also the characteristic curves vary compared to the usual respective AC equipment.

In general, cables with a larger diameter result in lower losses. They do, however, cost more. The benefit from lowering energy losses should be compared to this additional cost. Designing the system to minimize the necessary cable length will also help to reduce losses and will reduce overall capital costs. Since inverters have a limited number of inputs (often two or three) string boxes are used to aggregate the inputs from multiple modules, so that more modules can be grouped together as inputs for each inverter. String boxes are often off-the-shelf products and may also be equipped with protection and/or monitoring equipment.

[16] More information on connection requirements imposed by network operators may be found in section **Błąd! Nie można odnaleźć źródła odwołania.** of this report.

The level of lightning protection incorporated into a PV system is dependent on the lightning strike density of the area. Surge protection devices can protect equipment from induced surges resulting from lightning strikes or grid events. Lightning rods on rooftops may be required to protect the system, but the cost of installing these should be evaluated against the expected benefits. In addition, the proximity of the lightning rods to the modules should be considered, as hot spots in modules can result from partial shading. The use of frameless modules increases the likelihood that the system will require external lightning protection. All equipment should be adequately earthed, in accordance with local standards, in order for the system to operate safely.

In larger systems, power transformers are used to alter the voltage level in order to match that of the building or grid. The type or rating of the transformer depends on the off-take voltage level.

Energy meters measure electricity generated by the system and this data is used in assessing facility performance. If required, they can also measure and monitor peak power output, reactive power performance and the system's power factor setting. Many inverters are also able to record this data on an individual basis, allowing for performance monitoring of a portion of the facility. Data can be available for remote analysis, feeding into the facility's control.

2.1.5 PV system costs

The investment cost for a PV system may comprise different components, such as the development cost, the cost of financing, the equipment cost and the cost of installation/labour. Figure 16 provides an overview of the segmentation of turnkey cost in Euros/kWp for an average tertiary/commercial (ca. 100 kWp) system in Germany in 2013. Further reductions on the specific installation cost of 1.6 Euro/Wp can be witnessed in the same country (Germany) as depicted in Figure 19.

PV systems have recorded a dramatic decrease in investment cost, which was due to technological advancements as well as to economies of scale. A recent study (2016)[17] by the Fraunhofer Institute for Solar Energy has looked into the development of module prices over the years and produced the learning curve of Figure 17, highlighting the fact that on average a 19% cost reduction for every doubling of capacity was monitored.

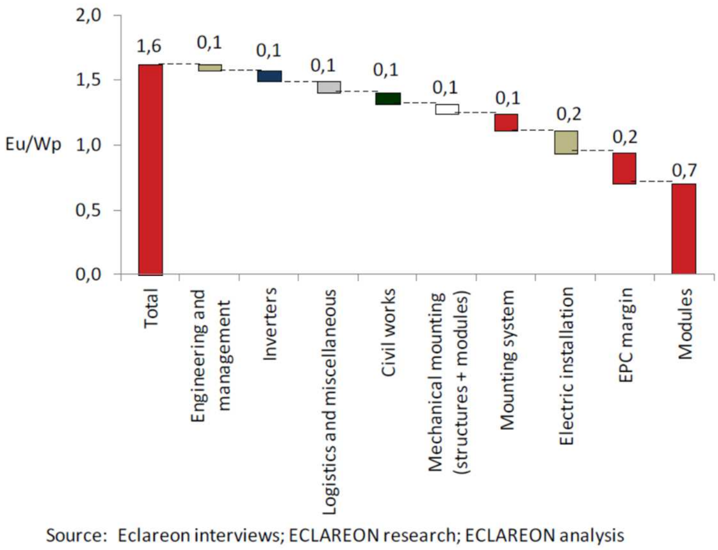
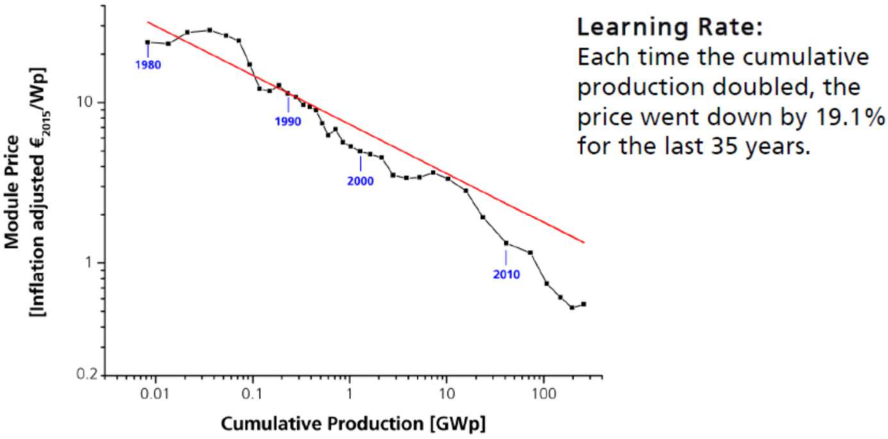


Figure 16: Segmentation of a PV System spectific investmetn cost in 2013 (Source: ECI[18])

[17] https://www.ise.fraunhofer.de/de/downloads/pdf-files/aktuelles/photovoltaics-report-in-englischer-sprache.pdf

[18] ECI Publication No Cu0187. Application Note – Medium Size PV Plant, Aug 2013 http://www.leonardo-energy.org/resources/227/medium-size-pv-plant-57f3c88606412



Data: from 1980 to 2010 estimation from different sources : Strategies Unlimited, Navigant Consulting, EUPD, pvXchange; from 2011 to 2015: IHS. Graph: PSE AG 2016

Figure 17: Commercially available PV Technologies price learning curve (Source: Fraunhofer ISE[12])

It is rather seldom to find cost figures for BIPVs due to the high-customisation of the solutions. The Swiss BIPV Competence Centre of SUPSI (Switzerland) and the Solar Energy Application Centre (SEAC, The Netherlands) compiled a report[19] on BIPV Product Overview for Solar Facades and Roofs: BIPV Status Report 2015, SUPSI – SEAC on which the costs for the broad categories of roof and facades are included. The energy density is not explicitly mentioned in the report but since the module technology varies, it can be estimated that its range should be between 60 and 180 Wp/m^2.

With respect to solar roofs, the PV products were, according to the aforementioned report, all found to be priced roughly 200 €/m^2 higher than the conventional roofing materials. The BAPV (Building Applied Photovoltaic) system price varied between 225 and 300 €/m^2 (note: This price range includes the roof tile underneath the PV panels, as these are required to make the roof water-tight in BAPV systems). For the in-roof mounting system the price varies between 350 €/m^2 and almost 500 €/m^2. For the BIPV tiles the price varied between 225 and 500 €/m^2. For the 'full roof solution" category, the price ranged from 200 €/m^2 to almost 650 €/m^2.

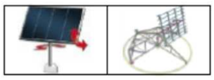
The price of the BIPV systems varied from 100-150 €/m^2 for a thin film PV cold façade (with a really simple sub-structures and a low-efficiency solar technology) to 750 €/m^2 for a high end PV solar shading system. This indicates the following important conclusion: for facades a very interesting price point has been obtained, as BIPV systems are comparable considering the price to conventional façade materials.

Further on in the cost discussion, the mounting equipment is mostly relevant for systems installed on flat roofs and they are selected mainly in order to optimise the annual energy yield of the system, by providing appropriate inclination. In their majority, these mounting systems refer to fixed tilt structures. An indication of the relevant costs for various systems is presented in Figure 18.

As already mentioned, PV modules installed in tilted roofs usually follow the given roof inclination due to aesthetic reasons and planning regulations. In this case, the mounting structure (mostly made by aluminium or by galvanised steel) uses less material mass, but has an additional cost factor, as there may be the need to ensure waterproofing.

[19] http://www.seac.cc/fileadmin/seac/user/doc/SEAC-SUPSI_report_2015_-_BIPV_product_overview_for_solar_facades_and_roofs_1_.pdf

The cost of inverters has also been reduced significantly over the past years, yet the reduction was not as steep as the one of the PV modules. Economies of scale do exist in relation to the capacity of the inverters, with larger systems equipped with central inverters being also able to minimize conversion losses. For rooftop systems a (few) string inverter(s) are usually enough, apart from larger commercial systems above 100kW. Nevertheless, the specific cost (Euro/kW) is always higher for the low capacity inverters. The following table gives cost figures for various types and sizes of inverters in Germany.

	Fixed mounted systems	Single-axis tracking systems	Double-axis tracking systems
Description	 • Fixed structure that does not follow the sun's trajectory • Mechanical simplicity • Lowest installation / O&M cost	 • Tracks sun with a single pivot point • Lower cost and maintenance compared to dual-axis	 • Tracks sun from east-west and north-south using two pivot points • Complex design due to more motors and sensors
Yield increase [1]	Not applicable	Up to 25% - 30%	Up to 35% - 45%
Price range [2]	15 – 25 EUR ct / Wp	30 – 40 EUR ct / Wp	75 – 95 EUR ct / Wp
Types		• Horizontal • Vertical • Tilted	• Tip-tilt • Azimuthal-altitude

Note: [1] Increase of production yield of installation with respect to fixed mounting systems, yield ranges indicate supplier sales information;
[2] Turnkey price, including structure supply and mechanical mounting (structure + modules)
Source: ECLAREON research; ECLAREON interviews

Figure 18: PV System support structures in 2013(Source: ECI[13])

Inverter / Converter	Power	Efficiency	Market Share (Estimated)	Remarks
String Inverters	up to 100 kWp	up to 98%	~ 37%	• 11 - 19 €-cents /Wp • Easy to replace
Central Inverters	More than 100 kWp	up to 98.5%	~ 61 %	• ~ 10 €-cents /Wp • High reliability • Often sold only together with service contract
Micro-Inverters	Module Power Range	90%-95%	~ 2 %	• ~ 35 €-cents /Wp • Ease-of-replacement concerns
DC / DC Converters (Power Optimizer)	Module Power Range	up to 98.8%	n.a.	• ~ 10 €-cents /Wp • Ease-of-replacement concerns • Output is DC with optimized current • Still a DC / AC inverter is needed • ~ 1 GWp installed in 2014

Data: IHS 2015. Remarks: Fraunhofer ISE 2014. Graph: PSE AG 2016

Table 2: Inverter/converter market (Source, Fraunhofer ISE[12])

In the same line of approach, considering the effect of economies of scale on investment cost, the IEA PV Technology Roadmap 2014 edition[20] provides a useful table (Table 3) with typical system

[20] https://www.iea.org/publications/freepublications/publication/TechnologyRoadmapSolarPhotovoltaicEnergy_2014edition.pdf

costs for residential, commercial and utility-scale systems in various countries. Economies of scale and the significant variation of system costs around the world can be easily seen.

USD/W	Australia	China	France	Germany	Italy	Japan	United Kingdom	United States
Residential	1.8	1.5	4.1	2.4	2.8	4.2	2.8	4.9
Commercial	1.7	1.4	2.7	1.8	1.9	3.6	2.4	4.5
Utility-scale	2.0	1.4	2.2	1.4	1.5	2.9	1.9	3.3

Sources: Friedman et al. (2014), *Comparing PV Costs and Deployment Drivers in the Japanese and U.S. Residential and Commercial Markets*, February, NREL/TP-6A20-60360; PV-PS IA (2014a), *PV Cost Data for the IEA*, personal communication, January.

Table 3: Typical PV system prices in 2013 in selected countries (USD) (IEA, 2014)

In comparison, IRENA foresaw in their cost analysis and projections as part of "The Power to Change: Solar and Wind Cost Reduction Potential To 2025" report[21] that an average utility-scale specific investment cost was at the levels of 1,810 (USD/kWp) in 2015 and it is expected to drop to 790 (USD/kWp) in 2025. Further information provided by selected countries, but also most importantly broken down into the utility-scale vs residential categories, may be found in IRENA's recent (2016) report[22] titled: "Letting in the Light".

COUNTRY	RESIDENTIAL	UTILITY SCALE
Brazil	3,210	2,022
China	1,550	1,439
Germany	1,632	1,200
India	1,500	1,403
Japan	3,200	2,130
US	3,571-4,603	2,336

IRENA

Table 4: Investment cost for solar PV power (USD per kilowatt) in 2015 (IRENA)

Putting the pieces together, it is interesting to see how the specific system cost has evolved and what is the relative contribution of PV modules against the Balance of System (BOS) in that final figure. Such information is depicted in Figure 19 and Figure 20, which show the evolution of installation cost for systems of a wide capacity range in Germany and Italy respectively.

Further reductions on the PV modules, as well as efficiency increase, is gradually expected for a horizon up to 2040 to 2050 so in certain cases we might see repowering projects for PV as we gradually witness for the older wind power projects.

[21] http://www.irena.org/DocumentDownloads/Publications/IRENA_Power_to_Change_2016.pdf
[22] http://www.irena.org/DocumentDownloads/Publications/IRENA_Letting_in_the_Light_2016.pdf

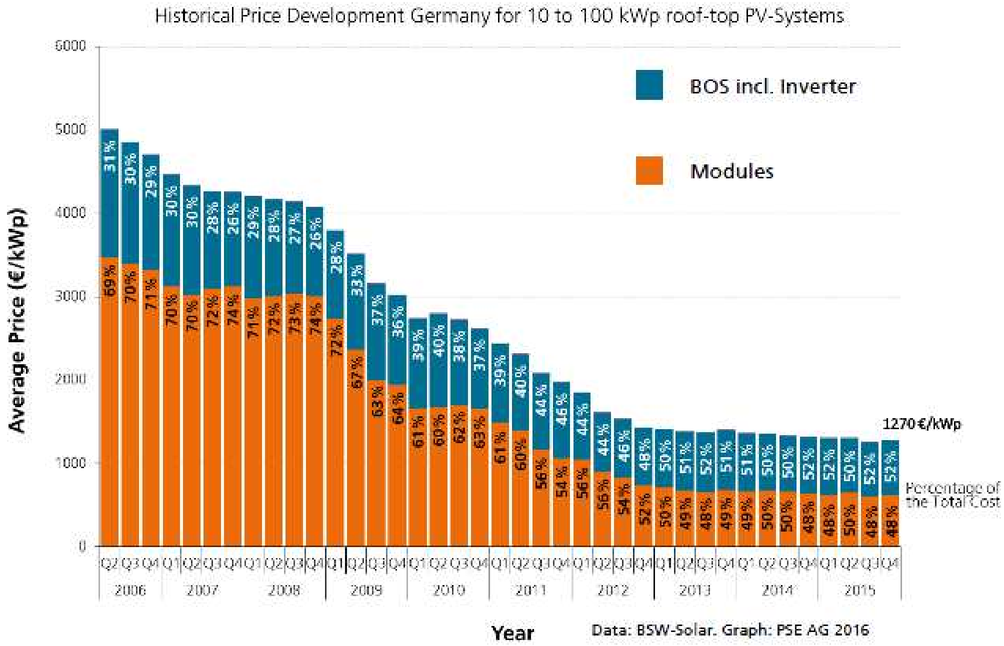


Figure 19: Evolution of roof-top PV system costs in Germany (Source: FHISE[12])

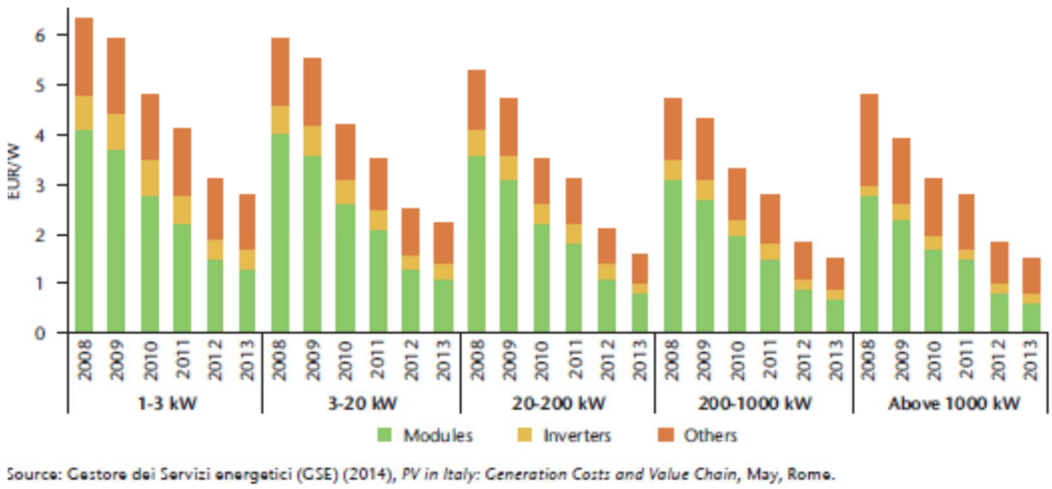


Figure 20: System cost development in Italy (Source: IEA[17])

2.2 Legal and regulatory specificities of building-PV systems

Whether building-attached or building-integrated, PVs in buildings are quite different from ground-mounted systems in a number of ways. From a technical point of view, a sole electromechanic approach is rarely sufficient since the architectural, static and environmental sides of the installation have also to be considered. Moreover, most importantly, the opportunity of self-generation has always been a consideration for solar PV in buildings and it is getting greater attention as the grid electricity price rises and the cost of electricity storage becomes competitive. Moving towards NZEB inevitably leads to the consideration of on-site RES production and solar PV is perhaps the most attractive, low-noise, no-moving parts and no-emissions electricity generation technology that can be deployed in the urban environment.

Responding to the above drivers, many policy makers and regulators have developed the framework that takes into account the technical, economic and environmental aspects pertinent to solar PV in buildings. These indicatively include:

- Permitting procedures (or in some cases obligations) for installing PV systems in buildings in cases of new buildings, public housing development programs, deep renovation of public buildings, etc. In certain cases, the installation of PV systems in buildings requires the mandatory installation of a solar thermal system for domestic hot water to be also in place.
- Environmental and construction code clauses, in which the installation of PV systems in buildings is explicitly prescribed in terms of the limits and prerequisites concerning their aesthetic, visual impact and surface coverage factor. Examples of such clauses include:
    - Obligations to follow the existing inclination on roofs and canopies and shading parts of a building;
    - the mandatory provision for a peripheral zone (e.g. a meter of distance from the roof's perimeter or the parapet, on which placement of PV modules is not permitted);
    - the maximum height of the mounting systems, as well as,
    - clearance distances from chimneys, antennas and aerial power lines.

- Rules for multi-storey, multi- apartment buildings on which the installation of a PV system may only be realised following e.g. a majority vote of the council of tenants/owners and the metering system is considered relevant to the common electricity installation of the building as whole;
- Standardised grid connection rules with appropriate queue management procedures and due care of ensuring transparency and non-discrimination among users. The major challenge, particularly due to the increased number of installations and their dispersed nature, seems to exist in determining distribution networks hosting capacity; that is the degree of PV penetration in the distribution network that does not lead to violations on the network quality standards;
- An adequate regulatory framework in which building load profiles and the coincidence (or not) of daily profiles with the respective generation profile of the PV system is taken into consideration. Storage in the form of battery banks that are properly sized so that they shift electricity from shoulder to valley areas of the building's daily electricity consumption profile is expected to be a game changer in what is called the "prosumer[23]" era of solar PV in buildings. So far, the prevailing regulatory frameworks for solar PV in buildings include:
    - **No compensation**: The prosumer does not receive any financial or other compensation for excess PV generation fed into the grid. This type of scheme is currently applied in Spain for installations up to 100 kWp[24].
    - **Direct selling**: The prosumer receives a bilaterally agreed price for every kWh sold into the market (usually by an aggregator). Such a price typically reflects the wholesale price of electricity and is therefore lower than the retail electricity tariff. This type of scheme[25] currently exists in Germany.

[23] More info on what the term prosumer refers to may be found below on **Błąd! Nie można odnaleźć źródła odwołania.**

[24]http://www.renewableenergyworld.com/articles/2015/10/spain-approves-sun-tax-discriminates-against-solar-pv.html

[25] Schemes of this kind including their variations are further discuss in section 4 of this report.

- **Netting (net billing, net metering)**: There is a monetary or energy netting between the electricity consumed from the grid and the one injected into the grid. The consumer receives credits (monetary or energy) for the injected electricity, which are later subtracted from the invoice of grid electricity consumption. Netting is used in several MS. As an example, a net billing scheme is in place in Italy (Scambio Sul Posto) which is based on a more complex formula that calculates the value of the excess energy fed into the grid (at wholesale prices). This value can be used as a credit for subsequent periods or is paid to the consumer.

2.3 The effect of storage in self-generation and the era of prosumers

2.3.1 Storage in decentralised PV systems in buildings

Recent technology developments have made it possible, and in some cases economically sensible, to combine domestic PV rooftop systems with storage units. The availability of lithium battery and turn-key systems of few kW on the market starts to make this option attractive for the domestic sector. Storage systems are the new frontier of PV installation. They are still confined in a niche market, nevertheless they offer services in terms of storage, balancing, availability and quality of electricity, which may become more attractive in the future in EU markets and already offer reliable solutions in transition and developing electricity markets, where there are frequent interruptions and a poor quality of service.

Whereas storage systems have no economic appeal in the case of Feed-in-Tariffs (FiT) and Feed-in Premium (FiP) schemes, because in these cases the economic incentive is attached to the sale of electricity, they start gaining some competitiveness in capacity based incentive schemes and also in markets where there is a significant spread between electricity generation prices and final consumer prices. Reform of net metering contracts, such as in Italy, have further improved the economic rationale of storage systems.

On the other hand, there is a number of barriers still present in relation to the penetration of storage systems:

- Financial: Currently PV storage systems for small domestic installations have a capital cost around 40-50% higher than a standard PV installation. Even if this investment cost can be recovered within time, financing for the domestic sector is still an issue.
- Regulatory: Most MS have not yet introduced regulations regarding the connection of storage systems to the distribution network. Technical security standards have not been developed and certification of products is not made possible. More advanced MS like Germany and Italy, with some limitations, have introduced secondary regulation to install storage units; that may be used as a paradigm.
- Technical: Despite lithium batteries offer a longer lifespan and deep discharging performance, the market still perceives technology uncertainties in the long run. As payback time is, in the best cases, close to 10 years, there is little or no experience of the performance of products on that horizon. Warranties for batteries are usually not granted for more than 5 years.

The main variable influencing PV storage deployment is the effect of incentive schemes and the rules of selling and exchanging electricity through the grid, which determine the difference between electricity generation and final consumer's costs. An example is provided in Box 1, where it is shown that, under certain regulatory conditions, the addition of a storage unit enables the increase of high value self-consumption, therefore improving the economics of the system.

In addition to the opportunity, under certain conditions, to further reduce the overall electricity costs of households or SMEs, storage systems offer the advantage of assuring availability of supply to final consumers in case of black out or poor electricity quality performance of distribution network. Notably, they may also provide the possibility for instant disconnection service from distribution network for balancing purposes.

2.3.2 Worlds collide: generation profile meets demand profile at a building level

Regardless of whether the building-PV system includes storage or not, small-scale self-production has gained momentum by the ever-increasing electricity prices and the reduction of ownership costs for these systems. It is worth mentioning that such systems were initially considered only for off-grid applications and storage used to be an integral component. On the other hand, the opportunity for on-site generation while the building remains interconnected with the distribution grid has been a key design consideration in energy efficient buildings. Historically, however, early regulatory framework conditions have led to the deployment of installations with a mere producer character as the subsidies provided for the electricity produced by small-scale building-PV systems favoured injection of the electricity to the grid instead of self-consumption.

BOX 1: Example of the economics of PV storage systems

Up to 2013 in Italy the incentive scheme for PV system was based on FiT and FiP. Each kWh sold to the grid received a remuneration ranging from 10 to 40c€/kWh according to the 5 different schemes implemented through time. In addition, the net-metering system was based on physical exchanges of electricity, independently of the value of kWh on the time of use.

With the phase-out of FiT and FiP, the net-metering scheme was reformed so that the netting was applied only to the generation cost component of the electricity bill (some 10c€/kWh as compared to some 23c€/kWh valorisation when exchanged with the previous net metering rules). Furthermore, with the introduction of a fiscal incentive which works as a capacity incentive, the economics of storage systems have got closer to the cost of standard PV roof installation.

By comparing the cost of a roof mounted 3kW PV system and a 3kW PV system with a 2kWh storage capacity we observe that under central assumptions the payback period is still slightly longer with PV storage system but comparable with a standard installation.

Description	Unit	Standard 3kW PV system	3 kW PV system with 2 kWh storage units
Standard Equipment	€	3000 (including inverter)	2000
Additional costs related to storage (batteries and inverter)	€		3500 (including inverter)
Installation and project development	€	2200	2200
Total	€	**5200**	**7700**
Total with VAT	€	**5720**	**8470**
Annual expected production	kWh	3474	3474
Electricity self-consumed	kWh	1042	2606
Electricity in net metering	kWh	2432	869
Valorisation of electricity in self-consumption	c€/kWh	0.23	0.23
Valorisation of electricity in net metering	c€/kWh	0.1	0.1

Total value self-consumption	**€/yr**	**240**	**599**
Total value net metering	**€/yr**	243	87
Total value tax rebate (50%)	**€/yr**	286	424
Total annual value	**€/yr**	769	1110
Expected payback time	**year**	**7,4**	**7,6**

Socket parity[26] prospects, energy efficiency obligations, as well as the development of the electricity markets have collectively led to a situation where a building-PV system presents the opportunity to switch role from an on-site generator to an exporter to the grid from time to time. This type of operation is commonly referred to as "prosumer" from the combination of words producer and consumer. It is interesting to see how these terms are defined by different organisations:

Organisation/Output	Proposed definitions
The European Consumer Organisation (BEUC): [27]	**Self – generation:** is power and/or heat generation on the premises of a private consumer **Self-consumption:** in turn is the use self – generated heat, or electricity by a consumer in order to cover his/her own demand to a certain degree. On top of that, it entails feeding excess electricity production into the public grid or eventually storing electricity **Prosumer:** is another term for consumers that self – generate and self – consume electricity on their premises.
European Commission[28] (Best practices on Renewable Energy Self-consumption, SWD(2015) 141 final, 17/5/2015)	The **self-consumption** rate is the amount of electricity actually consumed onsite as a percentage of the total electricity produced
International Energy Agency – Photovoltaic Power Systems Programme (Review And Analysis Of PV Self-Consumption Policies[29], Report IEA-PVPS T1-28:2016)	**Mechanisms of self-consumption:** Mechanisms promoting self-consumption of PV electricity are based on the idea that PV electricity will be used first for local consumption and that all this electricity should not be injected into the grid. The further classification of mechanisms of self-consumption includes: • Self-consumption, if energy consumption take place in real-time (or per 15 minutes); • Net-metering: An incentive scheme that allows compensating production and consumption during a larger timeframe (up to one year or more);

[26] http://www.iea.org/publications/freepublications/publication/TechnologyRoadmapSolarPhotovoltaicEnergy_2014edition.pdf (Cf. Page 16)
[27] http://www.beuc.eu/publications/beuc-x-2016-001_jmu_welcome_culture_for_solar_self-generation.pdf
[28] http://ec.europa.eu/energy/sites/ener/files/documents/1_EN_autre_document_travail_service_part1_v6.pdf
[29] http://iea-pvps.org/index.php?id=353

Organisation/Output	Proposed definitions
	• Net-billing: In case where the compensation can be calculated on a cash-flow basis, rather than an energy basis. **"Prosumer**[30]**"**: refers to an electricity consumer producing electricity to support his/her own consumption (and possibly for injection into the grid). **Self-consumption vs self-sufficiency**: The ratio of self-consumption describes the local (or remote under some schemes) use of PV electricity while the self-sufficiency ratio describes how PV production can cover the needs of the place where it is installed.
Council of European Energy Regulators (CEER Position Paper on Renewable Self-Generation[31], Ref: C16-SDE-55-03)	A definition of **self-generation (SG)** is not readily available. Prosumer, self-generators and self-consumers are words sometimes used interchangeably. For the purpose of the [CEER Position Paper on Renewable Self-Generation] paper, the Council of European Energy Regulators (CEER) considers self-generation as the use of power generated on-site by an energy consumer in order to reduce, at least in part, the purchase of electricity from the grid.
European Photovoltaic Industry Association (now Solar Power Europe) (Self Consumption of PV Electricity, Position Paper, July 2013[32])	**Self-consumption**: The possibility for any kind of electricity consumer to connect a photovoltaic system, with a capacity corresponding to his/her consumption, to his/her own system or to the grid, for his/her own or for on-site consumption, while receiving value for the non-consumed electricity which is fed into to the grid. **Net-metering**: A simple billing arrangement that ensures consumers who operate PV systems receive one for one credit for any electricity their systems generate in excess of the amount consumed within a billing period. In this case, production and consumption are compensated over a larger time frame (up to one year), and the network should be regarded as a long term storage solution, with the PV electricity being occasionally injected and consumed later on.

Table 5. Prosumer and related definitions (own compilation, sources as per indivitual footnote)

From the above brief review, it can be concluded that concepts and definitions may vary, but what is essentially meant to be described is the effect of having the PV generation profile and the building demand profile netted (see Figure 21). Of course, the network plays any important role in the off-take of excess electricity and the electricity market in the valuation of it. In the net-metering scheme

[30] In an earlier (201) IEA-RETD publication titled: "Residential Prosumers: Divers and Policy Options" the following slightly different definition is included: "*in the electricity industry, the term prosumer is used to refer to energy consumers who also produce their own power from a range of different onsite generators (e.g. diesel generators, combined heat-and-power systems, wind turbines, and solar photovoltaic (PV) systems).*" (http://iea-retd.org/wp-content/uploads/2014/06/RE-PROSUMERS_IEA-RETD_2014.pdf)

[31] http://www.ceer.eu/portal/page/portal/EER_HOME/EER_PUBLICATIONS/CEER_PAPERS/Electricity/2016/C16-SDE-55-03_Renewable%20Self-Consumption_PP.pdf

[32] http://www.solarpowereurope.org/fileadmin/user_upload/documents/Policy_Papers/Self_and_direct_consumption_-_Final_version_of_the_Position_Paper_02.pdf

the PV systems notionally appears as if it uses the network as storage. It stores energy to the grid while in surplus and use energy while in deficit. The economics, however, of this scheme are rarely fair for the rest of the grid end users as they do not reflect the changes in the value of electricity across the settlement period (particularly in the case where the period by which net metering is settled coincides with billing period i.e. monthly or more).

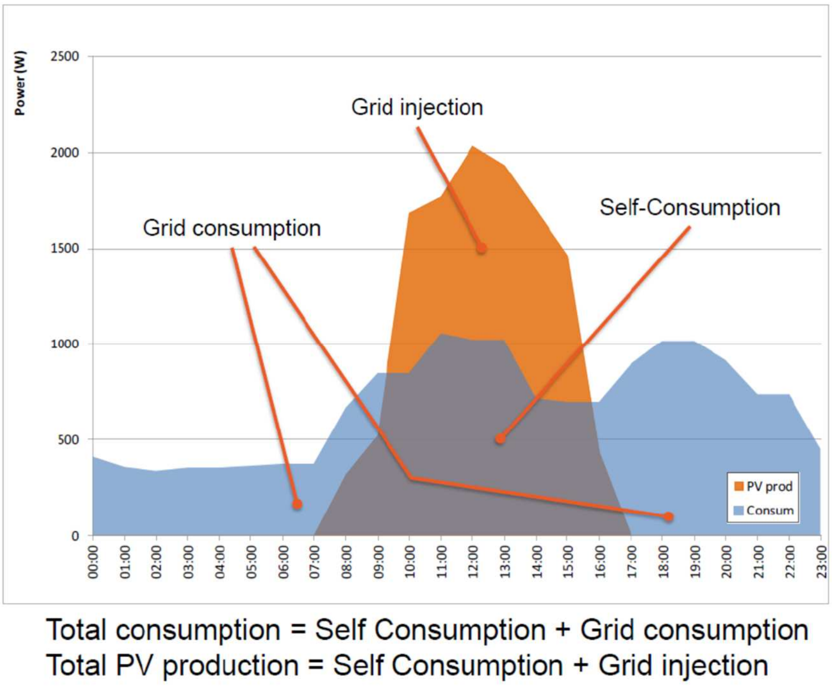


Figure 21: Solar PV in a typical household generation vs demand profile (Source: EPIA, 2013)

Prior to discussing the impact on the networks and the market it is worth looking at the different perspectives one may have in relation to the installation of solar PV systems in buildings. More specifically, those who are mainly concerned with energy efficiency may deem the portion of electricity consumed on-site as an energy conservation measure; it is locally produced and therefore it does not need to be generated in central power plants and transported through the grids to the point of consumption. Then, those who are mostly concerned with the increase of RES penetration in the energy system may see the proportion of excess electricity entering the grid as decentralised production. In reality, it is both.

Concluding - temporarily, and as a preamble on the detailed discussion to follow later regarding business models and regulatory frameworks - it is useful to include in this section the basic models of a prosumer (in the form of a building solar PV system). These models according to the IEA-PVPS Review and Analysis of PV Self-Consumption Policies report[33] are presented in Table 6 and are briefly explained thereafter.

Prosumer models definitions in Table 6 above include:

"A – Pure self-consumption with constraints

Self-consumption is allowed but the savings from the electricity bill are reduced by some additional fees or taxes. In addition, the electricity injected into the grid is not remunerated and thus lost for the prosumer. In order to be competitive, the PV system must produce electricity

[33] http://iea-pvps.org/index.php?id=353

significantly below grid parity to compensate for the additional costs. Such business models will also promote local self-consumption through demand side management, storage and/or a decrease in system size.

B – Pure self-consumption with a feed-in tariff for the excess electricity

This situation is the classical definition of self-consumption, as implemented for instance in Germany (in some market segments). Self-consumed electricity allows savings on the electricity bill of the prosumer while excess PV electricity is bought at a predefined tariff. Such feed-in tariff can be fixed, or based on the average wholesale price of electricity thanks to aggregators.

C – Net-billing

While self-consumption assumes an energy netting (kWh produced are locally consumed and reduces the electricity bill naturally), net-billing assumes two different flows of energy that might have different prices associated with. The costs related to these two flows are netted to calculate the reduction for the prosumer electricity bill. In this business model, we will consider that the compensation for the excess electricity will be below the price of electricity. Grid-parity is considered to be reached.

D – Net-metering

Net-metering is the business case in which the excess PV electricity is remunerated at the same price of the wholesale[34] price of electricity. Some countries have adopted net-metering systems where prosumers have to pay some additional grid charges or taxes but this will not be considered in this business model. Grid-parity is considered to be reached. In some countries, if this is not yet the case, an additional incentive can be paid on top of the net-metering system.

E – Pure self-consumption is the case in countries where grid parity has not been achieved yet.

In case grid parity has not been reached yet, self-consumption could be incentivised using two following ways: by awarding an incentive on top of the retail electricity price for part of electricity that is self-consumed or through a certain value for excess electricity injected into the grid, higher than the market price (possibly higher than the retail electricity price as well)."

[34] We note however that in our analysis presented below in this report net metering quantities in specific jurisdictions e.g. Greece and Italy is based on the retail price

		Production based: classical "FiT" - style. No self-consumption	Self-consumption with constraints	Self-consumption + FiT	Net-billing	Net-metering	Self-consumption + Premium
1	Right to self-consume	Not Allowed	Yes	Yes	Yes	Yes	Yes
2	Revenues from self-consumed PV	N/A	Savings on the electricity bill	Savings on the electricity bill	Netting of production revenues and consumption costs	Savings on the electricity bill	Savings on the electricity bill
	Additional revenues on self-consumed PV	N/A	No	No	No	No	Premium
3	Charges to finance T&D cost	N/A	Yes	No	No	No	No
4	Revenues from excess electricity	N/A	Zero	< retail price	<= retail price	= retail price	> retail price
5	Maximum timeframe for compensation	N/A	Real-time	Real-time	Long period	Long period	Real time

Table 6: Prosumer models summary (IEA-PVPS, 2016)

2.4 Grid integration of PV-based distributed generation

2.4.1 Power systems transition and overview of impacts

Renewables as a whole have been a key driver for development of power systems and electricity markets. It is well-known that the electricity industry has viewed in the early days the integration of RES with some reluctance, as their intermittent production schedules were hard to be accommodated by the power systems at large portions and most importantly, their total generation costs were quite high compared with the conventional technologies.

A lot have changed since those early days however and the game has changed to such an extent that traditional vertically integrated electricity utilities have already moved forward with more sustainable business models. The current trends show that large energy companies invest in RES, steadily increasing their share in the respective generation portfolios. This strategy appears as a promising business diversification particularly for those energy undertakings that had to divest their transmission business due to the liberalisation of the European electricity markets. On the other hand, since the cost of RES generation dropped sufficiently to compete with conventional generation – a fact in which the persistent policy support efforts have greatly contributed to – both the network development and the markets' operation had to adapt to this changing environment. Nowadays, network planning takes seriously into account the fact that the majority of new generation is RES-based while conventional generation is gradually decommissioned. Network expansion and flexibility are required for the power system to move on to a new de-carbonised future.

In addition, operational demand forecasting has recently got a new meaning since Transmission System Operations (TSOs) need to have adequate weather forecasts based on which they take into account RES generation from various sources in order to come up with residual demand forecasts or "residual load" as it is commonly referred to (i.e. energy demand for consumption minus RES energy injected to the grid at the same time).

Finally yet importantly, electricity markets have gradually but steadily moved away from the perception that RES are a "necessary-evil" – that is, the mandatorily off-taken subsidised generation. With a more mature/controllable technology and experience on output forecasting, RES installations are in the course of being gradually exposed to the market - provided that they undertake reasonably controllable risks.

The purpose of this section would surely be exceeded if the above were to be discussed in their deserved detail. Nevertheless, it is noteworthy to take down the following points in relation to the impact of RES and in-particular building-PV systems on the electricity grids and markets:

- PV integration at a decentralised and small scale implies connection at distribution network level, but the higher the penetration rate the higher the impact on transmission system;
- Distribution is likely to experience hosting capacity issues which in turn relate - in order of significance - with voltage rise at feeder level, reverse power flows and transformer capacity saturation;
- Transmission is likely to experience increased decentralised PV generation as residual load, grid congestion and an increased need for reserves;
- Electricity markets at large may experience displacement of low-cost generation in the merit-order (due to mandatory offtake of PV generation), forecasting errors and - consequently - price spikes in the intra-day and balancing markets.

The International Energy Agency (IEA) Photovoltaic Power Systems Programme (PVPS) in a 2014 report[35] titled: "Transition from Uni-Directional to Bi-Directional Distribution Grids" provides a sequence of stages through which an increased penetration level might develop in time. The sequence of stages is depicted in Figure 22.

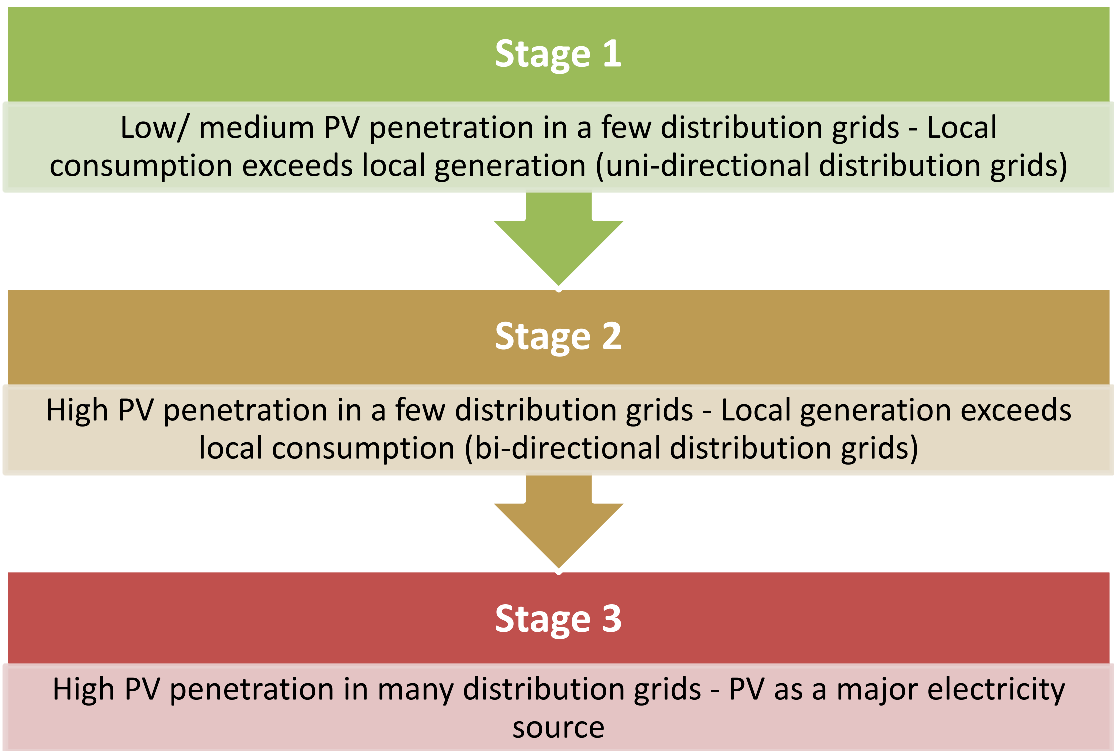


Figure 22: Power system development stages as PV penetration grows (Source: IEA-PVPS, 2014)

[35] http://iea-pvps.org/index.php?id=294

Following the identification of the above development stages, the aforementioned report presents a comprehensive illustration on how this transition may be experienced by Transmission System Operations (TSO) and Distribution System Operators (DSO). It also notes emphatically that:

*"For a technically reliable and cost-effective transition from one stage to another **it is extremely important to have the technology and the regulatory framework ready** when effectively needed. This requires **continuous adaption of network codes and laws** in regards to high national PV penetration scenarios from an early stage on. Neglecting this process of early adaptation will most likely result in high grid integration costs as retrofitting of existing PV systems will become necessary".*

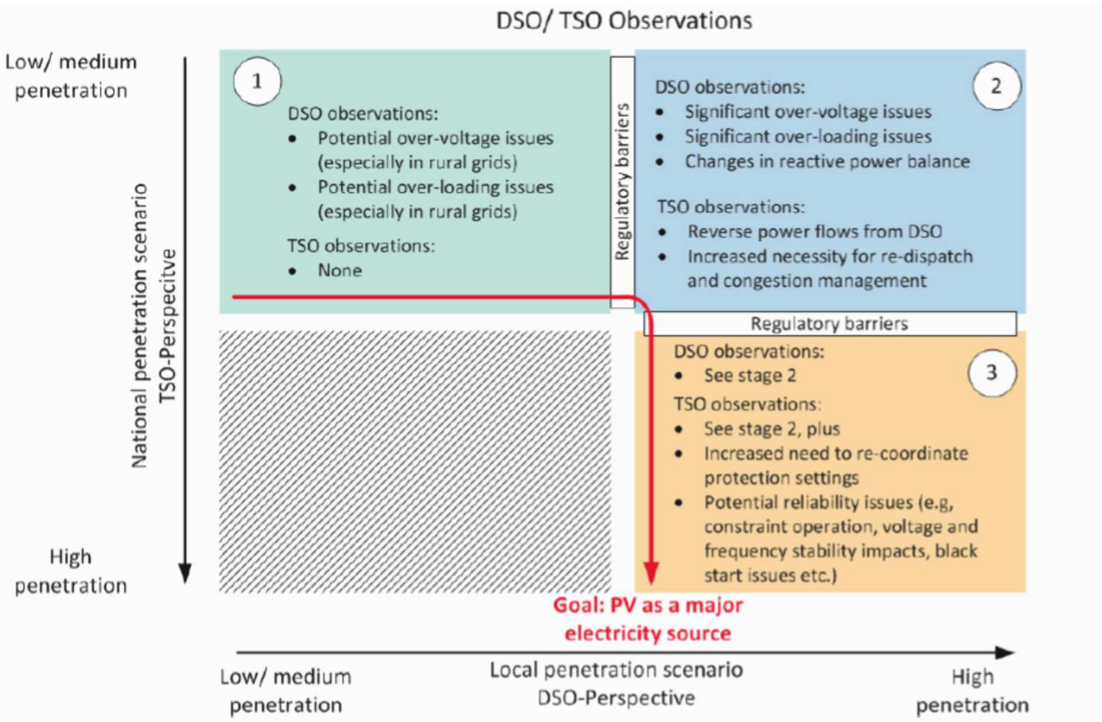


Figure 23: Definition of PV penetration stages and potential technical observations by distribution system operators (DSO) and transmission system operators (TSO) (Source: IEA-PVPS, 2014)

2.4.2 Specific considerations in relation to an increased PV penetration rate

2.4.2.1 Centralised vs decentralised generation

Based on a working assumption suggesting that the legal and regulatory framework will be enough to trigger a sustainable growth for PV systems a question arises: would it be preferable for policy makers to opt for utility scale (possibly multi-MW) power plants or for small-scale decentralised units? Intuitively, both comprise advantages; on the one hand, utility scale power plants do not imply any significant shift in network topology and to a certain extent planning and operational experience of network operator has reached sufficient levels already. Moreover, economies of scale are always preferable when it comes to costs. On the other hand, decentralised generation may be more cumbersome in terms of network planning and operation but may induce benefits like avoided network expansion or reduced need for reserves (due to the intra-cancellation of multi-point deviations through aggregation).

A study[36] titled: “Integration of Renewable Energy in Europe”, prepared for the European Commission and released in June 2014 has looked into the subject by engaging in an EU-wide simulation exercise. The results of the study “*do not show any clear advantage for either centralised or decentralised generation*.” However, the study does provide several “*important insights into the role of distributed generation on infrastructure requirements and the costs of electricity supply. In particular, the analysis in this study has shown that:*

- *The choice between decentralised and centralised generation in a given region does not have any direct impact on the need for transmission and back up capacity;*
- *Distributed generation may both cause and avoid distribution expansion, depending on:*
    - *Type of Distributed Generation (i.e. controllable resources vs. variable RES-E and correlation with load);*
    - *Penetration of Distributed Generation;*
    - *Vertical distribution (i.e. connection level);*
    - *Horizontal distribution (proximity to load and transformer stations);*
- *Need for distribution expansion can be strongly reduced when combined with more flexible demand or decentralised storage.*

The above conclusions are quite interesting notwithstanding the fact that the exercise was based on a pan-European level (and not at a national one) and the fact that it collectively addresses RES (and not PV technology only) based on a set of predefined RES development scenarios. As a broader conclusion we may keep in mind that any dilemma related to the promotion of centralised vs decentralised generation shall not have to weight upon the effect on network expansion and reserve capacity.

2.4.2.2 Hosting capacity

One of the ever first questions on the debate around distributed generation - in which PV technology has always been in the forefront due to the advantages it comprises in being installed on buildings, at an urban environment and consequently within the big load centres - was how much distributed generation can the distribution network accommodate while preserving the given quality standards.

Solar Power Europe in their report[37] titled: “Connecting the Sun”, (2012) propose the following definition for hosting capacity:

“*The PV hosting capacity of a distribution grid can be defined as the PV Direct Current (DC) peak power (Wp) that can be connected to the specified grid without lowering the security of supply or leaving the boundaries for high power quality. The hosting capacity is therefore determined by the maximum loading capacity and set by the dimensions of the network equipment and infrastructure, as well as the applicable codes and requirements on the power quality (voltage limits).*“

Looking further into the constraints determining hosting capacity there seems to be a consensus among various research approaches and analyses on the following:

- Voltage rise
- Transformer loading
- Cable loading

[36] https://ec.europa.eu/energy/sites/ener/files/documents/201406_report_renewables_integration_europe.pdf
[37] http://pvtrin.eu/assets/media/PDF/Publications/other_publications/263.pdf

The report combines the effect of the last two bullet points above suggesting that "*In practice, there are two factors limiting the hosting capacity: the maximum loading current and the maximum operating voltage. The hosting capacity varies widely from one area to another depending on local characteristics of the distribution grid itself.*"

Most experts in the field agree that the limiting effect of voltage rise comes a lot earlier into the scene compared to transformer and cable loading, and in most cases it comprises the decisive limiting factor in a feeder's hosting capacity.

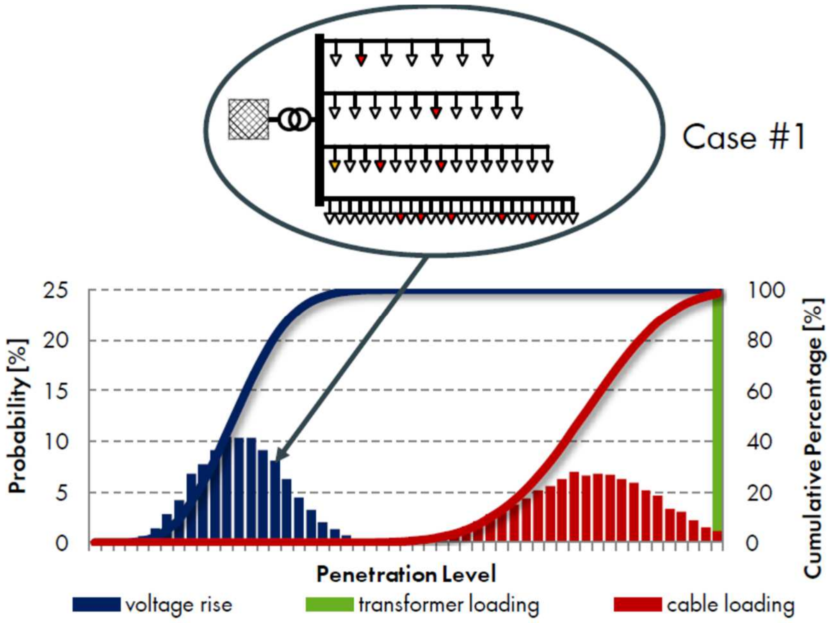


Figure 24: The combined effect of hosting capacity limiting factors (Source: IEA-PVPS, 2012[38])

Transformer capacity appears as the least expected factor limiting hosting capacity. Distribution transformers are designed for a certain maximum continuous current, but can carry much more current during a limited amount of time. In addition, in urban areas the coincidence in the profiles of consumption and PV output may lead to sufficient larger penetration margins compared to the nameplate capacity of the distribution transformer.

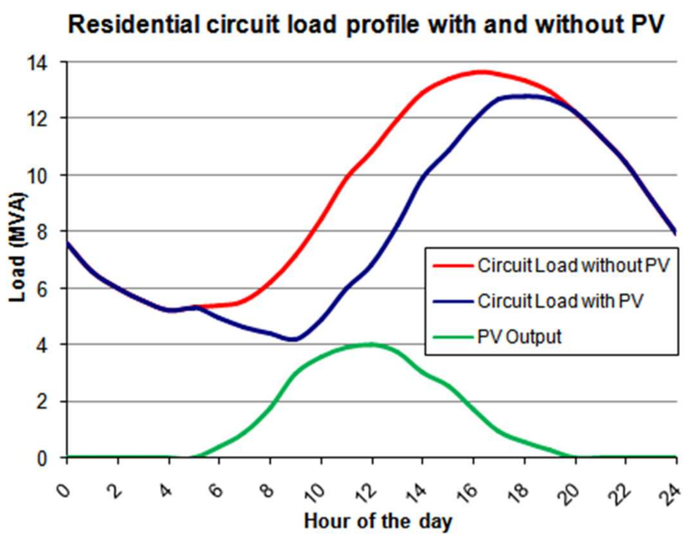


Figure 25: Residual demand at a household level (Source: DNV-GL, 2012[39])

38 Daniel Premm, SMA AG presentation at IEA PVPS Task 14 Workshop, Kassel, May 8, 2012

39 http://blogs.dnvgl.com/energy/pv-effects-on-distribution-systems

Cable loading appears to be the second most crucial limiting factor in the determination of a circuit hosting capacity. Network planners traditionally calculate allowed voltage drop, which by design has determined the cable cross-section, in the absence of any generation connected along the feeder. Adding PV generators modify the power flows in accordance to the proximity to the transformer (i.e. the point where the feeder starts) and the generation capacity. PV UPSCALE project funded by the Intelligent Energy Europe Programmes, presents a sample calculation, which illustrates the combined effect of PV capacity and positioning along the cable length for voltage drop levels of 2, 4 and 6% (Figure 26).

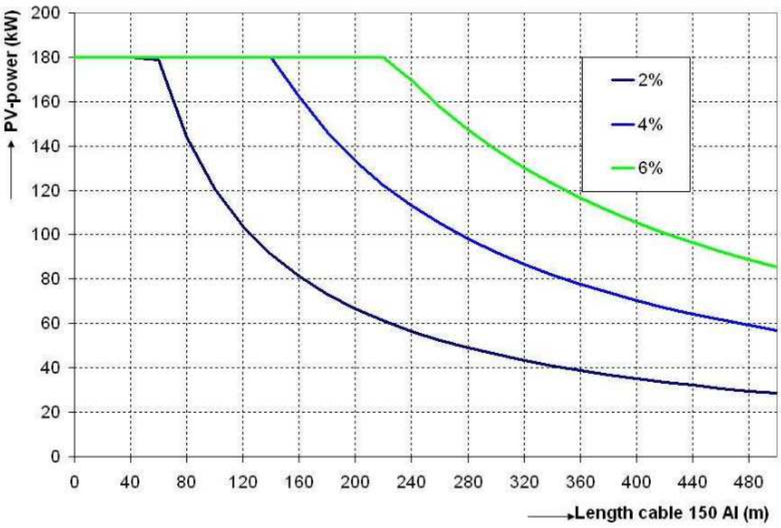


Figure 26: Maximum PV power which can be connected at one point of the LV branch cable (Source: IEE UPSCALE Project, 2008[40])

The situation with voltage variation is the most severe among the aforementioned constraints. When the production of power by distributed resources is high and the injections higher than load, power flows occur from the distribution level to the transmission level, and voltage rises locally; when the feed -in is low and the load is high, voltage may become too low.

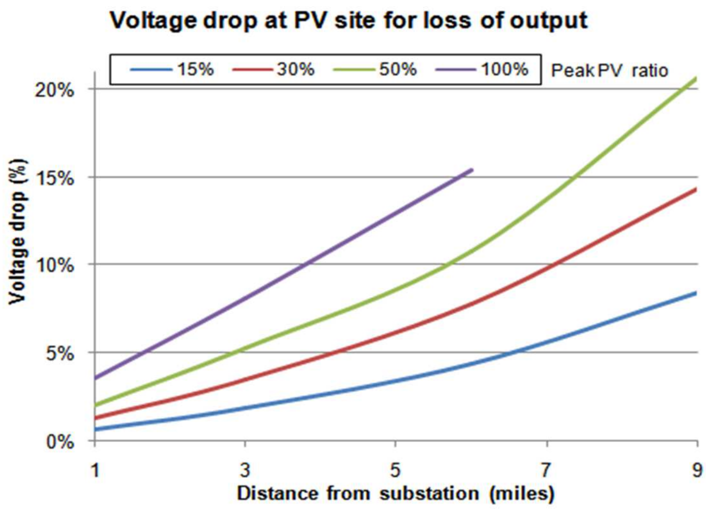


Figure 27: Voltage drop at various PV generation levels and high load condtions (Source: DNV-GL, 2012[41])

The above illustration (Figure 27) gives as a sense on what the anticipated voltage drop might be as a function of distance from the substation for four derating levels of a PV generator. Nevertheless, the opposite case of having excess voltages and reversed power flows at a MV/LV circuit in the

[40] http://www.pvupscale.org/IMG/pdf/WP4_D4-4_recommendations_V6.pdf
[41] http://blogs.dnvgl.com/energy/pv-effects-on-distribution-systems

presence of PV generators installed at the LV side is equally challenging. The following illustration (Figure 28) shows how voltage levels may look like in a an MV/LV circuit with or without PV generation connected at the LV side.

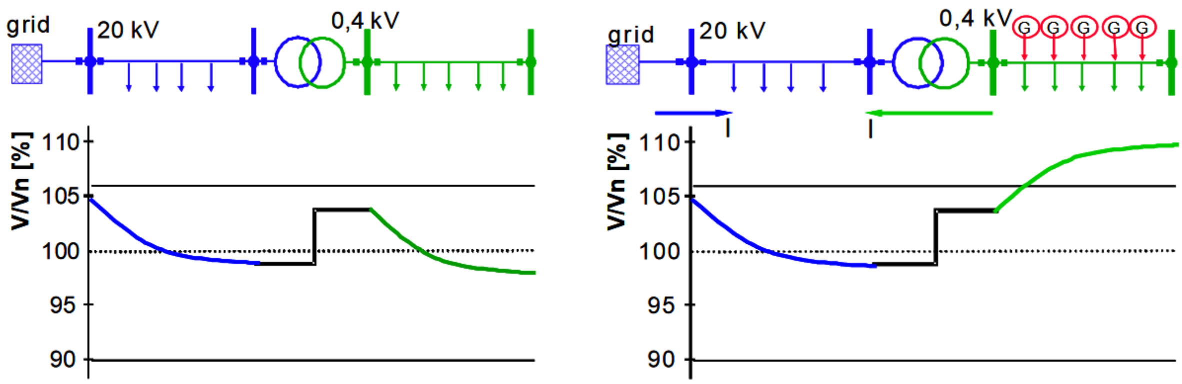


Figure 28: General distribution of voltage levels over feeder length without (left) and with (right) distributed generation (generation exceeds load) (Source: IEE UPSCALE Project, 2008[42])

Finally, yet equally important, the extended nature of the distribution network involving numerous feeders makes the assessment of hosting capacity a challenging and time consuming task. Network modelling based on annual operating data with and without PV generation for a single feeder is required for this exercise. The relevant extreme scenarios may define appropriate upper and lower thresholds:

- Maximum PV power – Maximum Load power = the Minimum Threshold
- Maximum PV power –Minimum Load power = the Maximum Threshold

However, in order to determine the hosting capacity for a distribution network that covers an area (e.g. a city), statistical methods[43] are usually employed.

2.4.2.3 Network losses

For many years experts used to agree on the fact that distributed generation had a positive impact on network losses (i.e. reducing them compared to the scenario without distributed generation). This was particularly true for the distribution network and for low distributed generation penetration levels. The *PV Parity* project financed by the Intelligent Energy Europe programme in the report[44] titled "Direct Costs Analysis related to Grid Impacts of Photovoltaics", September 2013, concludes that:

"At low penetration levels, up to 10% energy penetration, PV connected at distribution networks is likely to reduce distribution network losses. Beyond this level, the trend starts to reverse. The threshold varies from country to country. Southern Europe where peak demand coincides with PV

[42] http://www.pvupscale.org/IMG/pdf/WP4_D4-4_recommendations_V6.pdf
[43] http://www.ieee-pes.org/presentations/gm2014/PESGM2014P-002752.pdf
[44] http://www.pvparity.eu/fileadmin/PVPARITY_docs/public/PV_PARITY_D44_Grid_integration_cost_of_PV_-_Final_300913.pdf

output is likely to have a higher threshold. The savings that PV brings in reducing the losses are estimated to be between 2.5 €/MWh and 5.6 €/MWh of PV output. This can partially compensate the other grid integration costs. However, the savings diminish with the increased penetration of PV. "

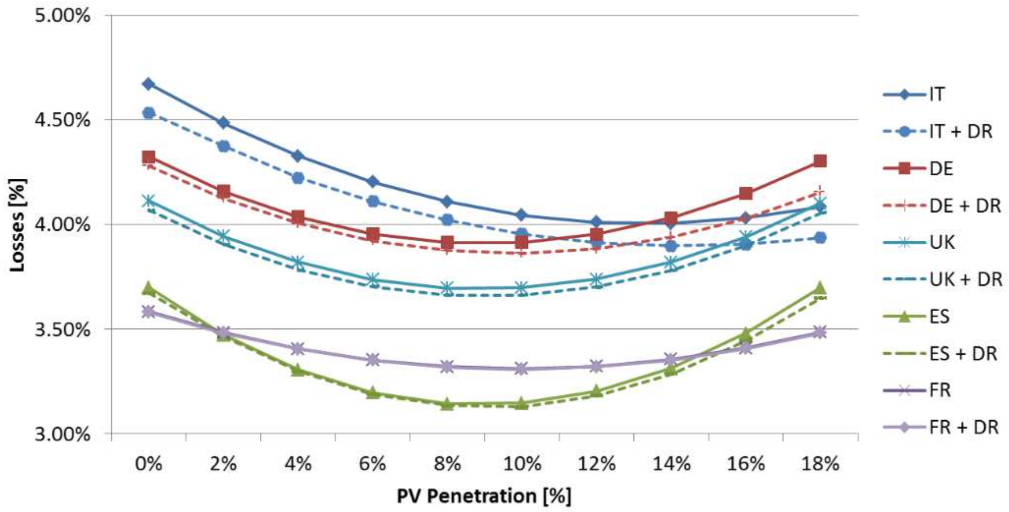


Figure 29: Impact of increased PV penetration on distribution network losses in Germany, Spain, France, Italy and the UK (Source: IEE PV Parity Project, 2013[45])

A more recent "Analysis of Distributed Generation and Power Losses" has been carried out by Viesgo Distribución (ES) and the results were presented in a Council of European Energy Regulators (CEER) Workshop for the Benchmarking Report on Power Losses on October 6, 2016. Though the study takes as a basis the specific characteristics of Viesgo networks i.e. network topology, generation units, loading levels, etc. and most importantly it regards wind, cogeneration and small-hydro as the distributed generation in the system, the outcome of the study (Figure 30) seems to be quite aligned with the conclusions of IEE PV Parity project presented above.

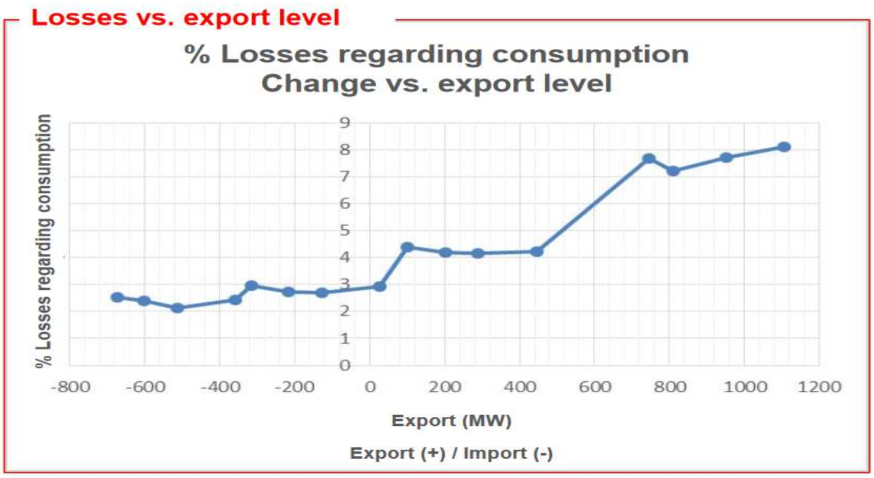


Figure 30: Impact of increased DG penetration on distribution network losses in Spain (Source: Viesgo Distribución, 2016)

For the better understanding of the above schematic (Figure 32), it should be noted that export is the situation where generation exceeds demand in the specific distribution network and thereby electricity is "exported" to the Spanish transmission grid. Conversely, "import" situation is when the

[45] http://www.pvparity.eu/fileadmin/PVPARITY_docs/public/PV_PARITY_D44_Grid_integration_cost_of_PV_-_Final_300913.pdf

generation in the Viesgo network falls short in covering the local demand and thereby additional power needs to be "imported" by the Spanish transmission grid.

The aforementioned studies however, do not expand to the effect of distributed generation on transmission losses particularly during the times when electricity flow is reversed from distribution network onwards to the transmission grid.

2.4.3 Impact on operations

Currently, the responsibility for balancing the control area of a power system (which usually coincides with the area enclosed within the national borders of many EU Member States) is by law exclusively entrusted to the TSOs. Therefore, while the need for an enhanced TSO/DSO coordination is universally recognised, the majority of operational impacts particularly related to the intermittent nature of RES are dealt with at the TSO level. The major issues that need to be mentioned in relation to operational impact include:

- The displacement of generation in the merit order due to priority and mandatory off-take of RES electricity;
- The effect on the residual load;
- Congestion and uncontrolled power flows (including loop flows involving neighbouring countries' grids) which is usually dealt with re-dispatch;
- Balancing, which may become a quite challenging issue if considerable forecasting error in short-term time-scales, is present with respect to the stochastic nature of certain RES installations' injections in the system.

2.4.3.1 Displacement of generation in the merit order

Price discovery mechanism in electricity markets, with the prominent example that of the day-ahead market, may be described as auctions; the price-quantity equilibrium occurs at the point where the supply meets demand and market clearing occurs at the marginal offer of the specific (marginal) generator. The auction is based on aggregated supply and aggregated demand. With RES being remunerated outside this market but being dispatched on a must-run[46] basis (mandatory, priority off-take as imposed by the RES Directive 2009/28/EC) it is as if RES are priced at zero shifting all conventional sources are to the right of the supply curve. At a given demand this phenomenon leads expensive (and subsidised) RES generation to displace the (normally cheaper in terms of total production costs) conventional generation and eventually leave out-of-merit generators that would normally be dispatched in the absence of RES.

This creates a dual fold situation. On the one hand, consumers bear the additional cost of having more expensive (usually FiT-remunerated) RES generation displacing cheaper generation, while on the other hand the latter is on a year round basis prone to financial losses if the annual hours of operation are not enough to cover at least their fixed costs[47]. The first part of the argument however does not hold true, if the overall subsidy cost (e.g. difference between FiT and marginal electricity price) is at least lower than the welfare gains derived by the increased RES generation, provided that these gains are depicted in the retail price. If not, the benefit comes all to the retail suppliers who may enjoy lower wholesale prices while the profitability of conventional generators is endangered.

[46] Priority dispatch of RES generation is proposed by the European Commission to be abolished as per the Clean Energy for All Europeans energy package (https://ec.europa.eu/energy/en/news/commission-proposes-new-rules-consumer-centred-clean-energy-transition)

[47] This is particularly true where price caps exist in the energy only markets

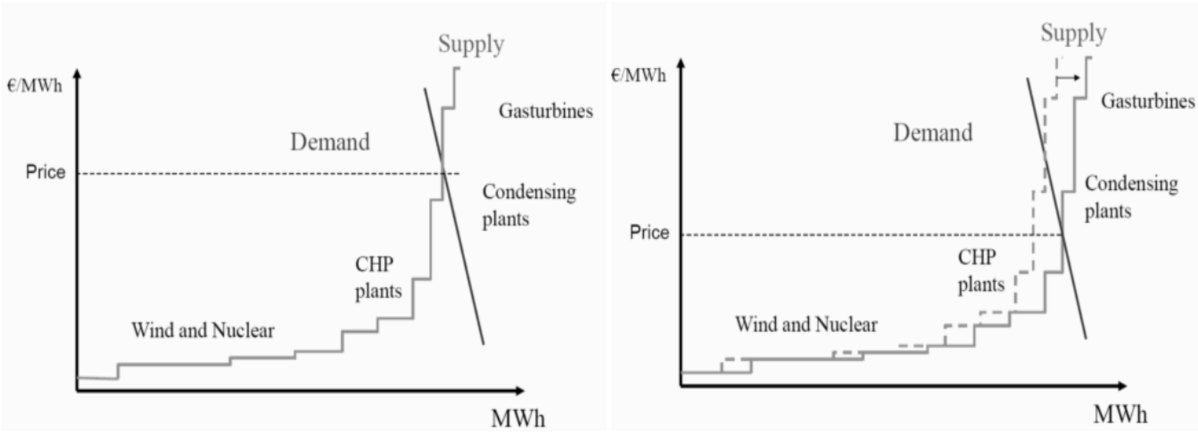


Figure 31: Merit- Order and Prices in a generic electricity market, with low wind output (left figure) compared to high wind output (right figure). Source: Morthorst (2008)

While RES cannot be blamed per se for creating the so-called missing money problem in energy-only wholesale markets, it is certain that enhanced RES penetration increases the severity of the missing money problem e.g. in case of a FiT, RES mandatory priority off-take regime.

Studying the issue from the perspective of capacity remuneration markets, which ultimately serve as a mechanism that incentivises new investments and prevents frequently out-of-merit generators from withdrawing the market, a study titled: "*Capacity Mechanisms In Individual Markets Within The Internal Electricity Market*" [48] carried out for the European Commission in 2013 presents examples of supply curves for four EU Member States. The supply curves reflect zero price bidding of must-take plants and shift to the right as the shares of must-take generation increase over time. The slopes of the supply curves depend on the evolution of the capacity mix. Open cycle plants, which have higher variable costs than Combined Cycle Gas Turbine (CCGT) plants, are needed to operate in the future to support the increasingly penetrating RES and as they have to operate few hours they are often old refurbished gas plants. As the utilisation rates of base-load plants (e.g. coal & nuclear plants) are lower due to RES penetration, investment in base-load is lower than in the past. The same applies to CCGT plants, but to a lesser extent.

[48] https://ec.europa.eu/energy/sites/ener/files/documents/20130207_generation_adequacy_study.pdf

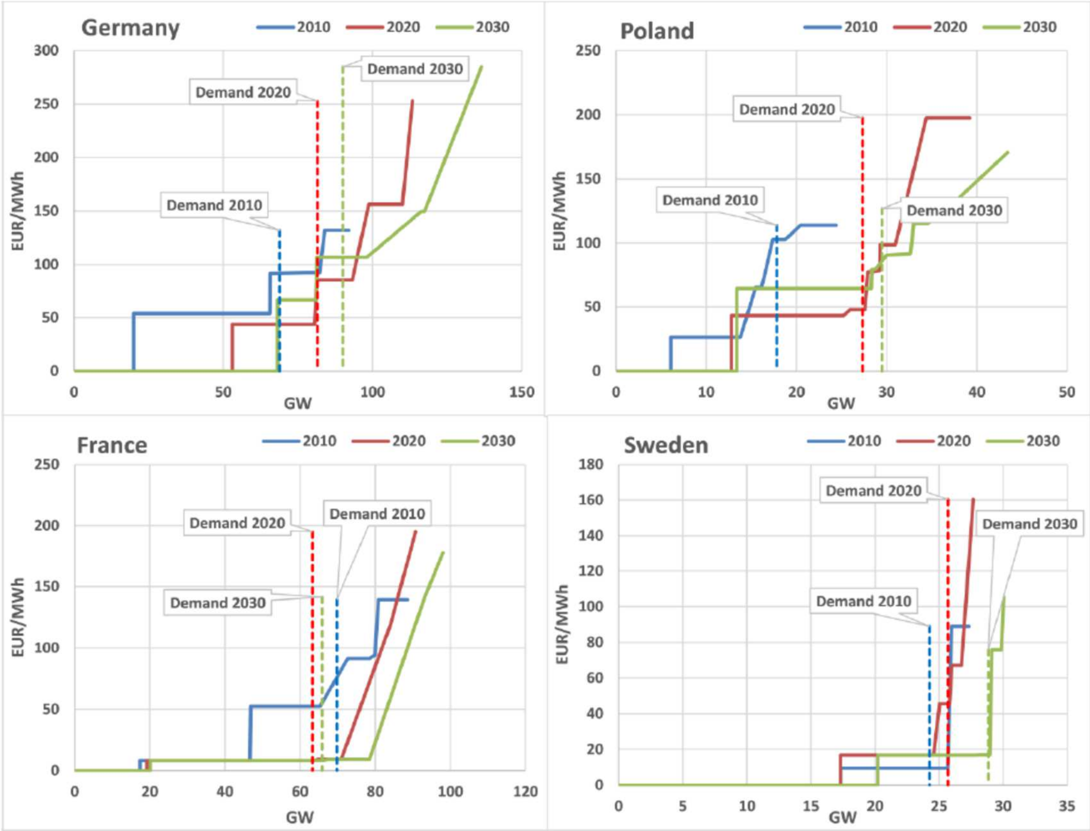


Figure 32: Evolution of supply curves in four EU Member states (Source: COWI, 2013)

2.4.3.2 *Solar power output characteristics and residual load*

As a first step it would be interesting to see the foreseeable output of a typical solar PV system in a year-round operation. Figure 33 bellow describes the normalised energy profile by which it is possible to model the output of PV systems during system studies.

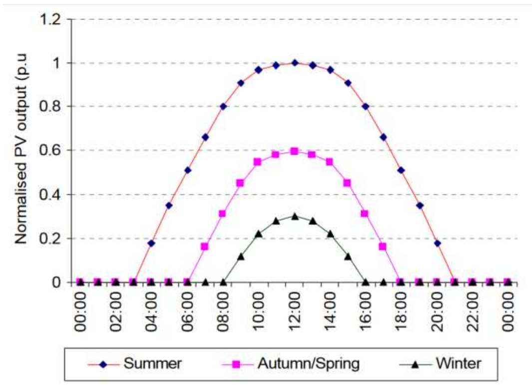


Figure 33: Normalised PV output profiles (Source: IEE RESPOND project, 2007[49])

Time and location play an important role in PV injections to the grid. Sun irradiation defines the PV production while the aggregated output at power systems level may be smoothened if geographical dispersion of the PV installations is sufficiently large. Solar Power Europe in the aforementioned

[49] http://respond.iwes.fraunhofer.de/results/200712%20RESPOND%20WP2%20Report%20D4.pdf, based on data from JENKINS,N. (1995) Photovoltaic Systems for Small-Scale Remote Power-Supplies. Power Engineering Journal,9,89-96.

report[50], illustrates the effects of aggregating solar PV output in the east-west axis of Southern Europe by aggregating the PV output profiles of Bulgaria, Romania and Portugal. The argument is valid of course provided that sufficient transmission capacity exists in the east-west corridor of Southern Europe, which would allow power to flow in the absence of local congestion problems.

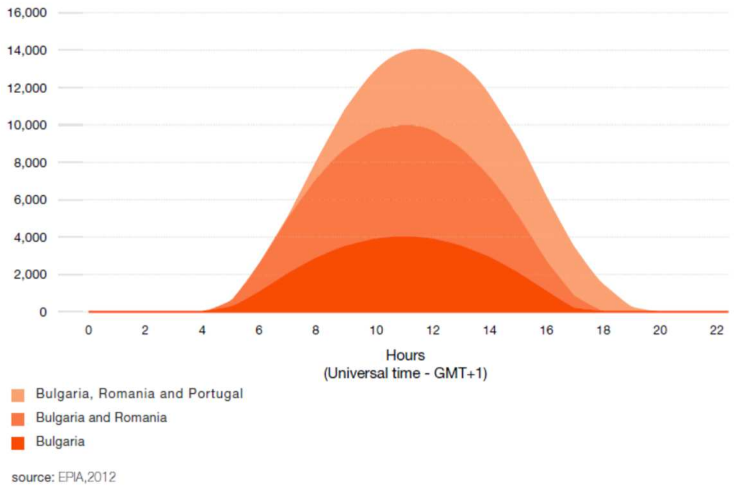


Figure 34: 2030 EU East-West PV production on a typical summer day (MW) (Source: EPIA, 2012[51])

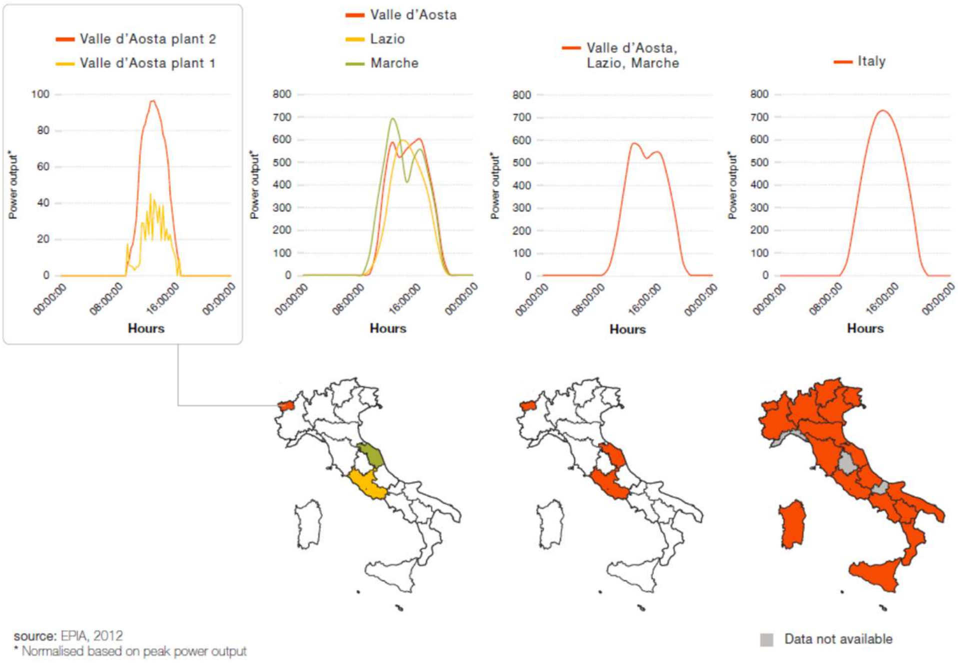


Figure 35: Comparison of daily PV variability (plant, region and country level) - Example of Italy (kW) (Source: EPIA, 2012[52])

Aggregation of PV output over regions at a smaller scale has equally interesting effects, particularly with respect to smoothen the anticipated output, as shown for the case of Italy in Figure 35. For instance, temporary shadowing effects caused by clouds in a region may be reduced in case of a higher number of solar plants.

Despite the beneficial effects of aggregation at regional levels, the issue that TSOs with systems presenting increased RES penetration levels have to deal with is the residual load, i.e.:

[50] http://pvtrin.eu/assets/media/PDF/Publications/other_publications/263.pdf
[51] 2030 EU East-West PV production on a typical summer day (MW)
[52] 2030 EU East-West PV production on a typical summer day (MW)

The load curve to be served by dispatchable thermal and main hydro generators is the residual load (RL), which is the actual load (L) minus production of wind (W), solar (S) and must-run generation.

This definition comes from an ENTSO-E publication[53] discussing the adaptation of the ENTSO-E Scenario Outlook & Adequacy Forecast (SO&AF) 2015 and the need for increased flexibility in the European interconnected network. TSOs are not only exposed to forecast errors at a time-scale close to real-time but also have to safeguard that adequate flexibility (cycling thermal power plants, dispatchable RES, X-border balancing cooperation, storage, interruptible loads, etc.) is available in the system in order to be used during the residual load ramping intervals.

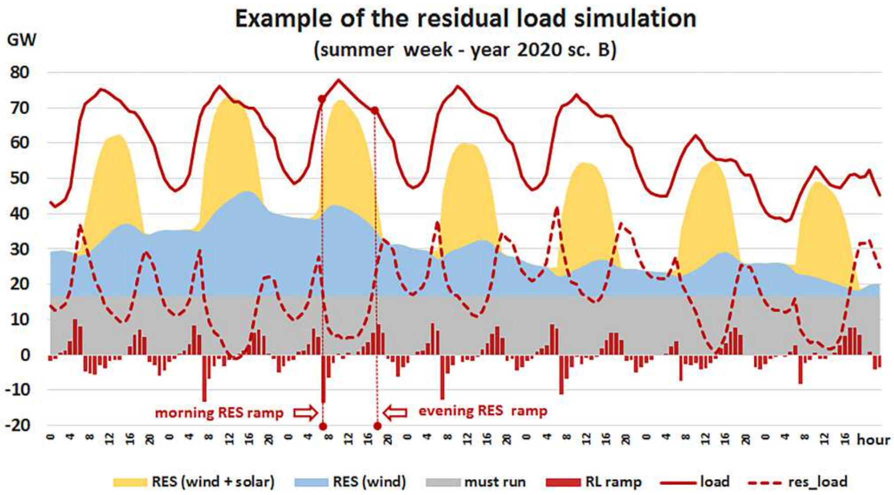


Figure 36: Weekly residual load simulation (Source: ENTSO-E, 2015[54])

The above-illustrated simulation in Figure 36 shows the need for thermal and hydro power plants to steeply ramp down as RES generation storms in shortly after sunrise, ramp up a bit slower close to sunset and remain at an increased output level as the evening peak approaches. In this particular case it is also evident that wind generation happens to be reduced with the anticipated reduced weekend load. It is however not always possible for TSOs to get the appropriate correlation between wind, PV and load evolution. Such a severe situation was experienced in Germany during a week in March 2013 as it was reported by the Federal Ministry of Economy of Germany. The following chart (Figure 39) presents how the market has been taken by surprise and responded with a positive price spike (109 €/MWh) on Thursday March 21, 2013, when both wind and PV generation happened to be quite low and thus the residual load rather high. Later in the week, on Sunday March 24, PV and wind generation reached almost simultaneously their peak output while the weekend load profile was still at its low levels. The residual load was temporarily minimised at the time and must runs made already the system long in capacity. The market responded with a negative price (-50 €/MWh) as the producers preferred to pay additional costs in order to remain synchronised and continue to generate at minimum stable generation instead of undertaking the short-term shutdown cost.

[53] https://www.entsoe.eu/Documents/SDC%20documents/System%20Adequacy/flexibility_v03.pdf
[54] https://www.entsoe.eu/Documents/SDC%20documents/System%20Adequacy/flexibility_v03.pdf

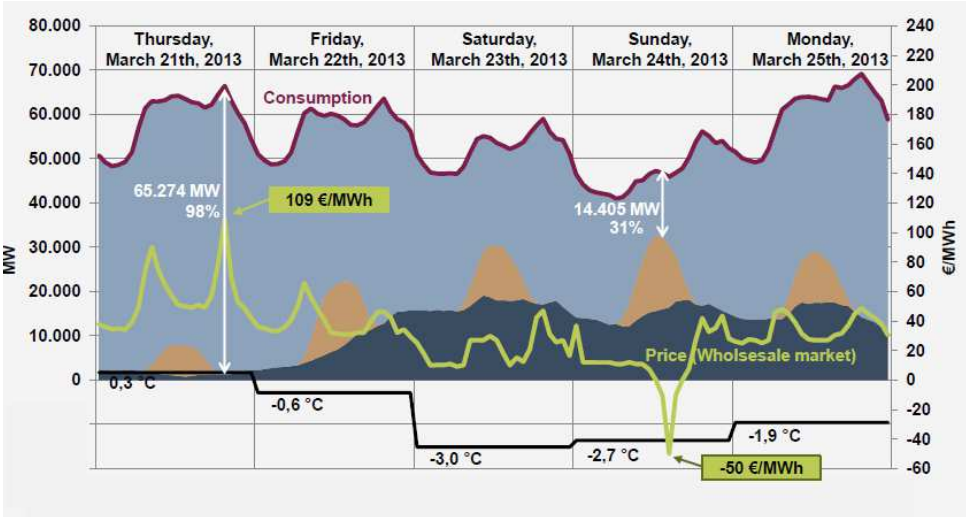


Figure 37: German electicity market response to high and low residual load (Source: BMWi, 2013[55])

2.4.3.3 Congestion Management

Congestion and/or uncontrolled load flows result from the fact that electricity flows are dictated by the laws of physics. In interconnected systems, electricity flows regardless of any national borders or even market rules in certain cases. In this sense, congestion and/or uncontrolled load flows are typical issues commonly faced by most TSOs with a few exemptions. For instance, there is no transmission congestion on the border of Austria and Germany. In the same region however, there are critical congestion problems in the North-South axis of the eastern part of Germany, which on several occasions have led wind power generation from the North Sea make its way to Southern Germany (Bavaria) via the Polish and Czech transmission systems.

It is worthwhile mentioning that the original purpose of interconnectors in Europe, which emerged following a long-lasted self-sufficiency doctrine, was initially reflecting the need for security exchanges. With the integration of regional markets, the interconnection capacity has gradually but steadily become a constrained resource. On the other hand, the resource-determined location of RES generation has also altered the topology of the network since power system planners could no longer have a definite influence on the location of new generation, which in turn was now dictated by the existence of RES potential combined with market-driven investment decisions. This situation gradually led to internal congestions – with a most characteristic example the aforementioned North-South axis of the eastern part of Germany which is controlled by the *50 Hertz* TSO[56].

Congestion is dealt with at European level in the manner provided in the Capacity Allocation and Congestion Management (CACM) Code, where it is foreseen that TSOs should use a common set of remedial actions, such as countertrading or re-dispatching, to deal with both internal and cross-zonal congestion. Moreover, in order to facilitate more efficient capacity allocation and to avoid unnecessary curtailments of cross-border capacities, TSOs should coordinate the use of remedial actions in capacity calculation. The following figure illustrates the strategy of *50 Hertz* TSO with regard to transmission congestion management:

[55] German Ministry for Economy (resp. for energy) – An Electricity Market for Germany's Energy Transition (Green-book) https://www.bmwi.de/BMWi/Redaktion/PDF/G/gruenbuch-gesamt-englisch,property=pdf,bereich=bmwi2012,sprache=de,rwb=true.pdf
[56] http://www.50hertz.com/en/

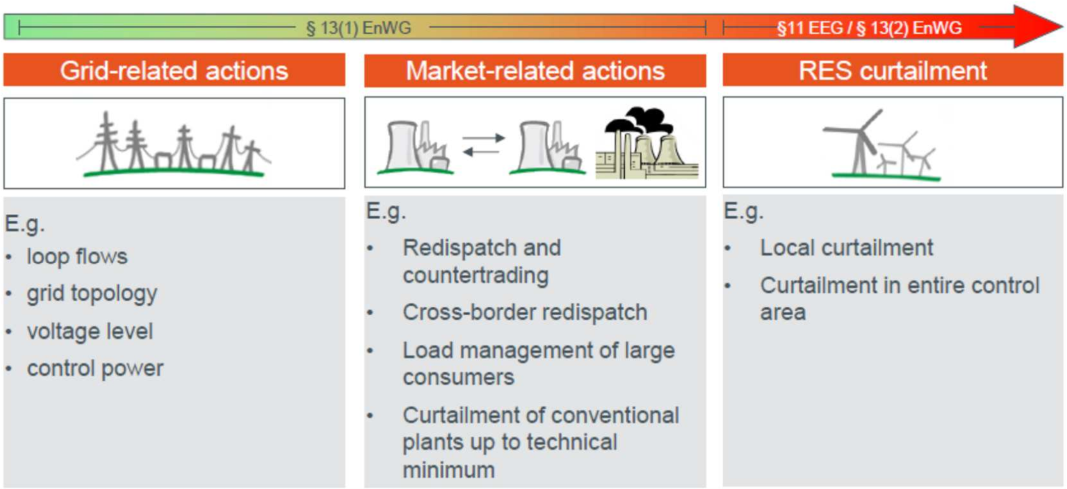


Figure 38: Transmission congention management practices (Source: Elia Grid International, 2016)

2.4.3.4 Short-term PV output forecasting and balancing

There are three major areas of discussion on the subject of electricity balancing in systems with an increased RES penetration:

- How can a TSO get reliable short-term forecasts so that due provision of adequate reserve availability is organised?
- How much reserve capacity is required and what would its properties be (response time, quantity)?
- Can RES and in particular PV installations offer ancillary services?

As previously mentioned PV output has both a seasonal but also primarily a diurnal pattern. We also discussed the effects of aggregation, which across large control areas tend to somehow smoothen the variability of PV output. Moreover, the times when PV generation represented a relatively negligible part of the generation mix seem to be long gone and should the cost reduction projections prove real, PV may even reach a top share in the generation mix of certain European countries.

Solar Power Europe in their report[57] titled: "Connecting the Sun", (2012) explain that "*the prediction of PV generation is carried out for different time horizons using different forecasting methods:*

- *Hours - or minutes-ahead forecasts (0 to ≃6h) are based on on-site data*
- *Hours - to day-ahead forecasts (>≃6h to a few days ahead) are based on satellite data and Numerical Weather Prediction (NWP) models*

Characterised by the effect of aggregation, as described above, the accuracy of forecasting improves when wider geographic regions and larger amounts of PV output are considered.

[57] http://pvtrin.eu/assets/media/PDF/Publications/other_publications/263.pdf

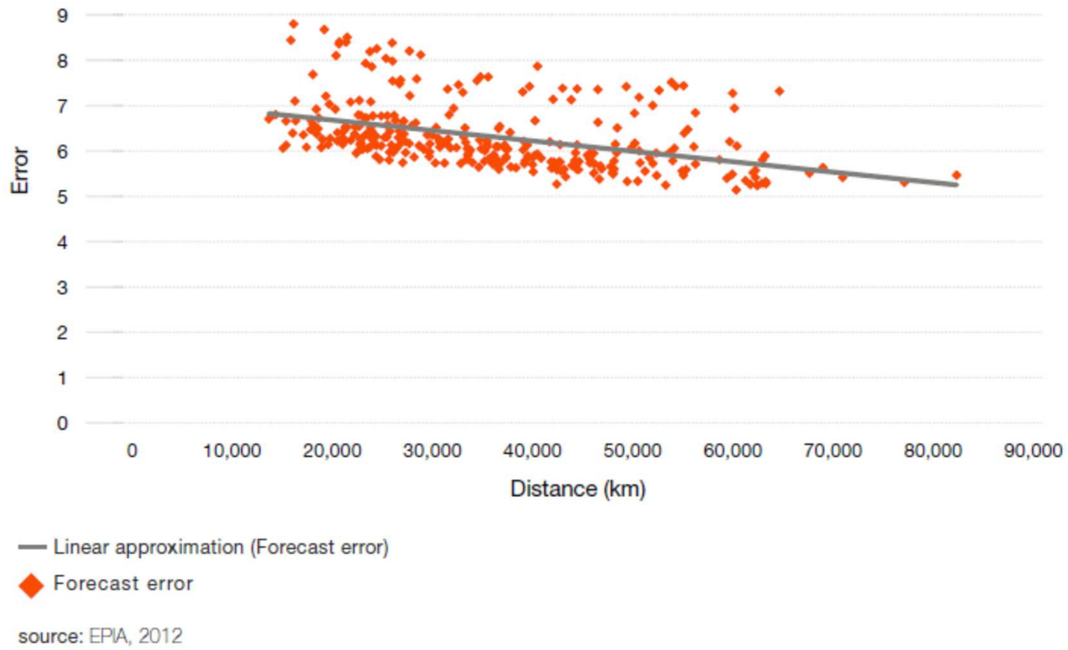


Figure 39: Forecast errors example of the production of a PV portfolio (%) (Source: EPIA, 2012[58])

As reported in the same document, the best forecasting methods achieve errors (Root Mean Square Error, RMSE) of 8% to 11% for day-ahead predictions of single plants. For larger portfolios and total regional production this number is much lower (4% to 5.5%). The latest information on the subject comes from *50 Hertz* TSO in Germany, which on summer 2016 was able to report a 3-6% RMSE. *50 Hertz* works with specialised forecasting service companies, which provide forecasts for three areas: Germany as a whole, *50Hertz* control area and each DSO region in this area. There are two forecast horizons: one that covers the period from 96 hours to days ahead and a short term one, which is for less than 8 hours. There are also three daily updates at ¼ hour short-term steps. The combined forecast results are derived from the accumulated experience of *50 Hertz* and are based on a linear combination of commercially available forecasts. It is worthwhile to mention that as *50 Hertz* reports, reaching this level of accuracy is a product of successive annual forecasting contracts. The TSO started with five service providers and currently works with those two that were able to provide the most accurate predictions.

In the context of operation planning, the natural variability of PV generation increases the required supply-demand balancing capability of a power system. The uncertainty of PV generation requires additional reserve capacity (i.e. conventional units operating under partial load so as to be ready to provide additional power when necessary in order to maintain system's frequency) resulting in additional costs for the system.

Regarding ancillary services, there is a general perception that RES technologies are relatively weak in providing standardised reserve products. In the case of PVs however, inverters are capable of providing certain limited ancillary services and therefore the integration of PVs in a distribution network should not be considered as a merely adverse effect. It can be briefly mentioned[59] that modern inverters offer at minimum Fault-Ride-Through (FRT) capability, active power limitation, and automatic power reduction at over frequency, reactive power control and active filtering.

Moving away from each individual inverter capabilities, we can again revert to the tools available to the TSOs, maintaining the foreseen frequency quality standards. At the industry level, the reserve products remain largely the same as have traditionally been developed and agreed since the Union

[58] 2030 EU East-West PV production on a typical summer day (MW)

[59] For more details please see: http://www.pvupscale.org/IMG/pdf/WP4_D4-4_recommendations_V6.pdf

for the Co-ordination of Transmission of Electricity (UCTE) era. At a European level, the details of electricity balancing are included in the relevant ENTSO-E Network Codes. It should, however, be noted that while the Balancing Network Code (EB) describes the market aspects (procurement methods, pricing, coordination, etc.) of electricity balancing, it is the Load-Frequency Control & Reserves (LFCR) Code that introduces imbalance netting as a means of regional optimisation of reserves. In 2015, the European Commission, ACER and ENTSO-E agreed to merge the three operational network codes into a single System Operation Guideline during their preparatory work for Comitology. The new guideline is composed of the former network codes on Operational Planning and Scheduling (NC OPS), Operational Security (NC OS), and Load Frequency Control and Reserve (NC LFCR)[60]. The System Operation Guideline is not anticipated before 2017.

The *PV Parity* project financed by the Intelligent Energy Europe programme in the report[61] titled: "Direct Costs Analysis related to Grid Impacts of Photovoltaics", September 2013 provides quantified insights on the frequency response requirements in Europe for the period 2020-2030. The study suggests that "*the increase in frequency response reserve requirements typically will be lower compared to the increase in operating reserves. The timescale for frequency response services is typically below 15 minutes while the operating reserve are needed to deal with much longer (up to 4 hours) credible system changes. With longer time frame, the uncertainty increases. Balancing cost should be in the area of 0.5 €/MWh and should rise gradually to the level of 1.04 €/MWh in 2030*".

In recent discussions (Sep 2016) with experts from two TSOs in central Europe[62] it turned out that as rule of thumb, European experience shows that an increase of installed RES capacity by 1 GW would lead to increase the control power demand by 25 -30 (up to 90) MW. While such a figure may vary from system to system based on its overall resilience, the specific *50 Hertz* experience suggests that there should be ca. 60MW available in secondary and tertiary control for every single 1 GW of wind or PV introduced to the generation mix.

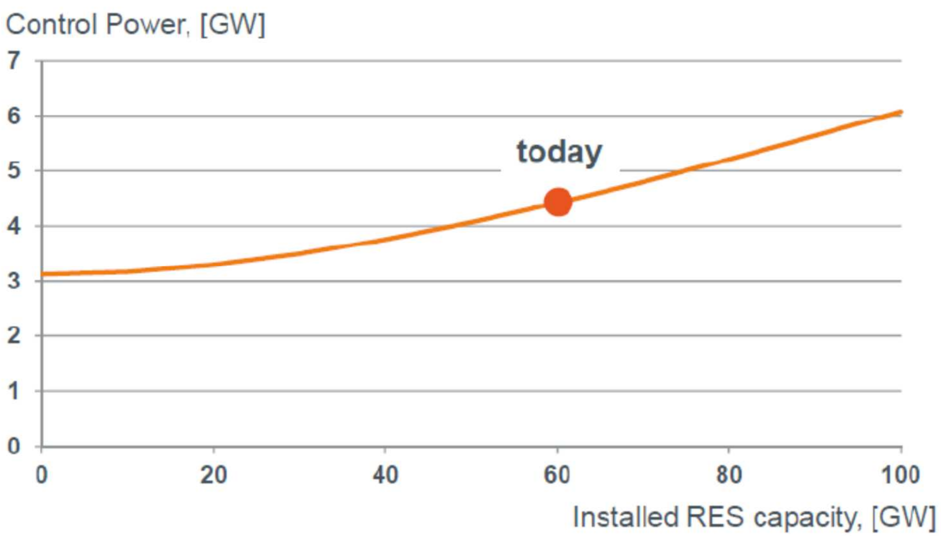


Figure 40: Impact of RES on demand of Control Power (Source: Elia Grid International, 2016)

2.4.4 Impact on infrastructure

[60] https://www.entsoe.eu/major-projects/network-code-development/system-operation/Pages/default.aspx
[61] http://www.pvparity.eu/fileadmin/PVPARITY_docs/public/PV_PARITY_D44_Grid_integration_cost_of_PV_-_Final_300913.pdf
[62] Elia (Belgium) & 50 Hertz (Germany)

What was described above as operational issues can only be regarded as such in the short run. In the long run, the more the network infrastructure adapts to the changing requirements the less the operational issues the TSO may experience. For example, congestion that may be created in cases of excess RES generation in a system may not be present if adequate infrastructure for carrying the load flows is available. Yet, building transmission lines in Europe is an effort that on average may take more than a decade regardless of its economic justification. Similarly, flexibility in the electricity system reduces the need for maintaining excess levels of reserves.

As far as the foreseeable future of the European electricity market is concerned, a study[63] titled: "Integration of Renewable Energy in Europe", prepared for the European Commission and released in June 2014 provides valuable insights on what the network capacity should look like if scenarios regarding demand and supply balance as well as the development of generation costs for a horizon up to 2030 are to be materialised.

More specifically, the aforementioned study finds that: *"Transmission expansion becomes increasingly important as the penetration of RES-E grows. Compared to the use of more centralised sources of RES-E, which are directly connected to the transmission grid, an increasing penetration of distributed generation will also require an extension of European distribution networks. However, the need for distribution expansion strongly depends on the type and penetration of DG, and different measures can be taken to minimize the need for distribution expansion."*

Quantified the above translates in several billion Euros to be invested on electricity networks in Europe for the period 2020-2030 in order to both be able to accommodate increasing demand and an increased penetration of intermittent RES in the system. *"On average, reinforcements at the HV level account for about one third of total cost, an MV networks for approx. one quarter"* as the study suggests and as it is illustrated in the figure below:

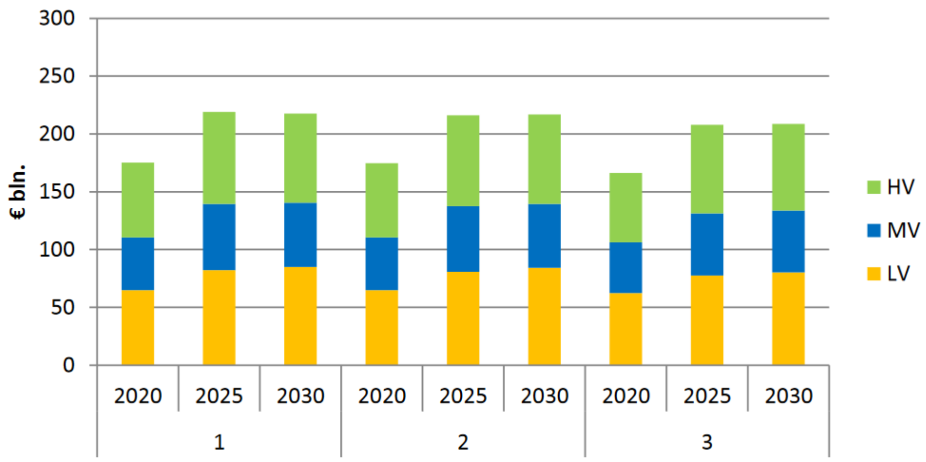


Figure 41: Cummulative distribution reinforcement costs in the main study scenarios (Source: Kema et. al, 2014[64])

PV Parity project financed by the Intelligent Energy Europe programme in the report[65] titled: "Direct Costs Analysis related to Grid Impacts of Photovoltaics", September 2013 also provides quantified insights on the required network infrastructure in Europe for the period 2020-2030. The scenarios considered reflect on a range of PV penetration levels between 2% and 18%. Most interestingly, the results of the analysis are presented in the form an indicator i.e. €/MWh of PV electricity produced.

[63] https://ec.europa.eu/energy/sites/ener/files/documents/201406_report_renewables_integration_europe.pdf
[64] https://ec.europa.eu/energy/sites/ener/files/documents/201406_report_renewables_integration_europe.pdf
[65] http://www.pvparity.eu/fileadmin/PVPARITY_docs/public/PV_PARITY_D44_Grid_integration_cost_of_PV_-_Final_300913.pdf

The analysis concludes that the additional grid cost for PV integration should be in the order of 0.5 €/MWh which should rise to the level of 2.8 €/MWh in 2030.

On the distribution level, as it was also discussed above, the existing condition of the distribution network (i.e. density, spare capacity), the location of the PV installations along the length of each distribution feeder, the overall penetration rate, as well as the degree of correlation between peak demand and output of PV do play a role as drivers for distribution expansion. In the aforementioned study, calculations of the additional distribution network investment for selected MS for a range of possible penetration levels between 2% and 18% were conducted. The following figure (Figure 42) shows the range of the resulted cost. The negative additional distribution network cost implies that for the specific possible penetration levels (between 2% and 18%) benefits would arise for the distribution system in the form of avoided network (expansion/rehabilitation) cost.

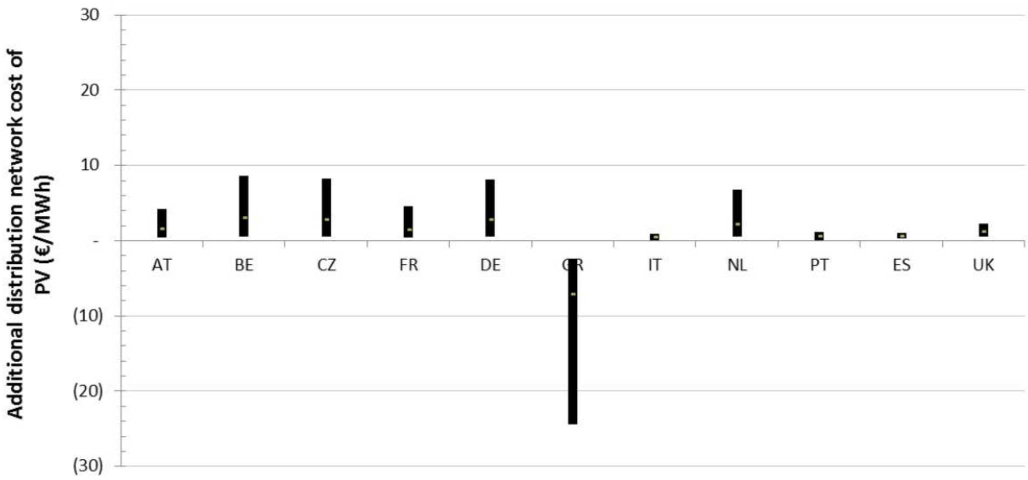


Figure 42: The range of additional distribution network cost of PV in Europe for various PV penetration levels (2% -18%) (Source: IEE PV Parity Project, 2013[66])

The need for coordination between the National Regulatory Authority, the TSO and DSO, in relation to network expansion planning and planning for connections of all those new distributed generation capacities shall also be highlighted.

With the gradual increase of RES penetration rates and a weather-dependent residual load, transmission planning is subject to additional uncertainties about where future generation may locate and how power will flow around the network.

The Ten Year Network Development Plan (TYNDP) and/or the relevant distribution network development plans should provide to prospective users (in this case potential generators from intermittent RES) the capacity of the network to accommodate injections from such RES plants at specific locations. An estimate of the costs involved should be also provided where feasible. This task involves network studies. The analysis should be performed, assuming weather patterns for RES generation and scenarios for installed RES capacities. Points in time with minimum and maximum system load should be analysed. In addition, the overall limit of the power system to accommodate such RES plants (e.g. wind and solar PV plants) should be analysed and used as a guide (or system-level constraint) in policy decisions concerning electricity from RES plants.

[66] http://www.pvparity.eu/fileadmin/PVPARITY_docs/public/PV_PARITY_D44_Grid_integration_cost_of_PV_-_Final_300913.pdf

IEA Photovoltaic Power System Programme in their report[67] titled: “Power system operation and augmentation planning with PV Integration”, released in 2014 provides an illustration of the above described iterative process proposed by Holttinen et al 2013.

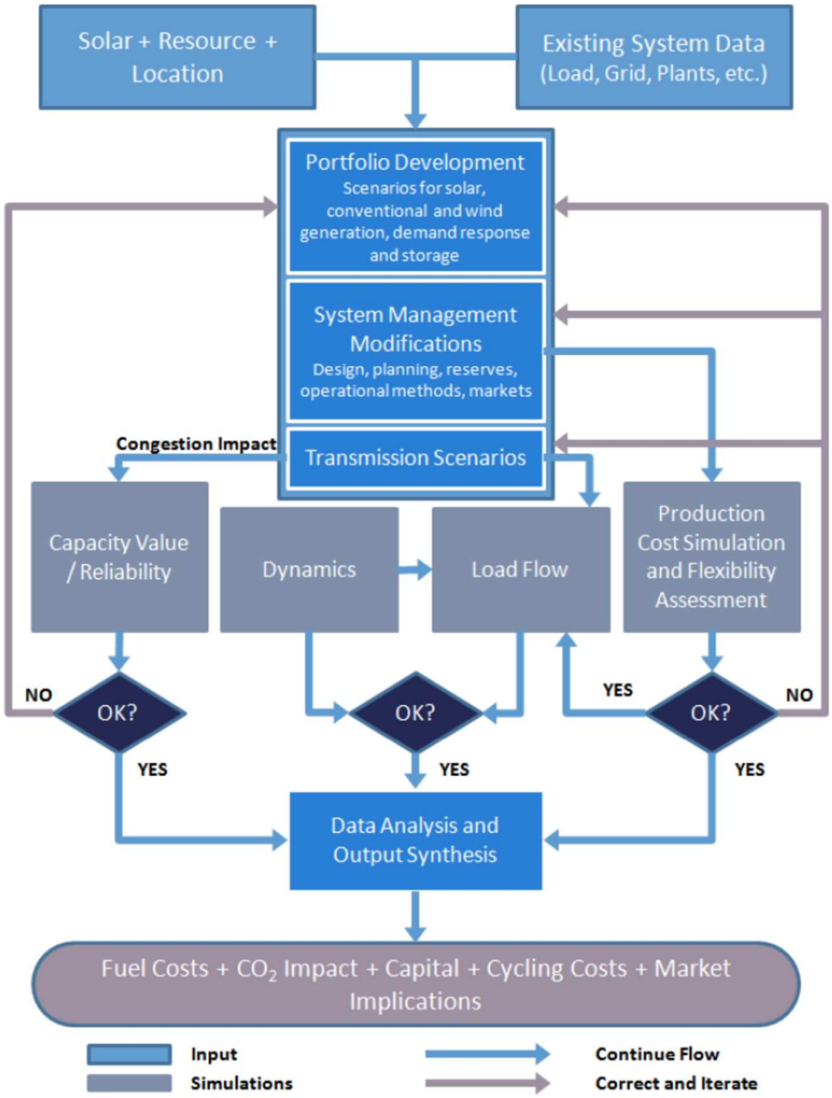


Figure 43: Adapting network planning process to account for PV integration (Source: IEA-PVPS, 2014)

As a common practice in the EU Member States, the Grid Code provides for the above, as well as governs the relationship between network planning and new connections. The Grid Code comprises national secondary legislation. Moreover, the Grid Code itself, being the usual text in which connection and network access are detailed in most countries around the world, encompasses chapters/sections/codes on planning and connection. The coherence between the planning and connection codes is more closely compared to all other sections.

[67] http://iea-pvps.org/index.php?id=322

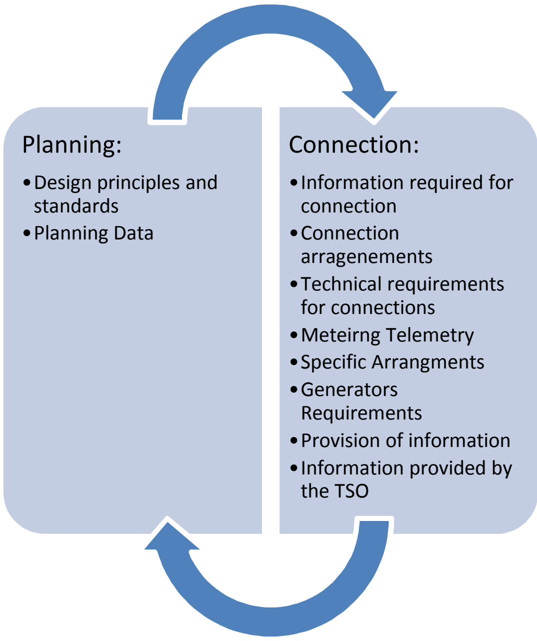


Figure 44: The relationship of Planning and Connections in the Grid code (adapted by the Irish Code for illustrative purposes) (Source: own illustration)

Connection of new users to the transmission grid might be constrained by network capacity, expansion or upgrade. This is usually the case with RES-E generating plants as the time requirement of permitting and installing such units is, in general, significantly shorter than that for network expansion and upgrade required by massive new RES-E connections. It is also common that governments/regulators first put effective incentives in place (e.g. in the form of generous feed in tariff systems) to encourage new RES-E generation while regulators usually lag or completely avoid to create similarly effective remuneration schemes for transmission and distribution companies for their grid development efforts.

This leads to a kind of the 'Chicken – Egg Problem', as it is related to the needs for transmission capacity for RES installations: on the one side (wind and solar developers) cannot go forward without transmission expansions built / financed by others (the TSO); on the other side (TSO and Utility - transmission system owner) will not commit to new grid construction out of fear that the new RES generation projects may not show up as promised due to uncertainties such as environmental licensing, financing, etc (stranded costs).

This asymmetry of incentives and the time lag between RES-E generation and network upgrade projects often results in competing investor requests (or **queues**) to develop certain renewable resources or to connect production facilities at given grid connection points.

Possible solutions to the above issues may include:

- Administrative procedures such as first-come-first served
- Market based solutions such as tendering available connection capacity in successive calls tendering
- Group processing of connection applications
- Granting non-firm access connections

Further information on the above may be found on an INOGATE Activity Completion Report[68] titled: “Further Assistance to GSE for the development of Connection Rules and becoming an Observer to ENTSO-E” (CWP 06.GE).

Specifically for the small-scale PV generators connection and with regard to the connection requirements, it needs to be mentioned that all national specifications in EU Member States comply with the European standards:

- EN 50160: Voltage characteristics of electricity supplied by public distribution systems
- EN 50438: Requirements for the connection of micro-generators in parallel with public low-voltage distribution networks

While these standards give general limits for public supply networks, various European countries have additional rules governing supply conditions. Many of these national regulations cover areas not included in the above-mentioned standards, such as the maximum permissible harmonic load to be connected to the PCC (point of common coupling) or the low voltage fault-ride -through behaviour among others. More information may be retrieved by Generator to the Grid Database[69] maintained by the European Distributed Resources Laboratories[70] (DER-Lab), which is an association of leading laboratories and research institutes in the field of distributed energy resources equipment and systems (see Figure 45).

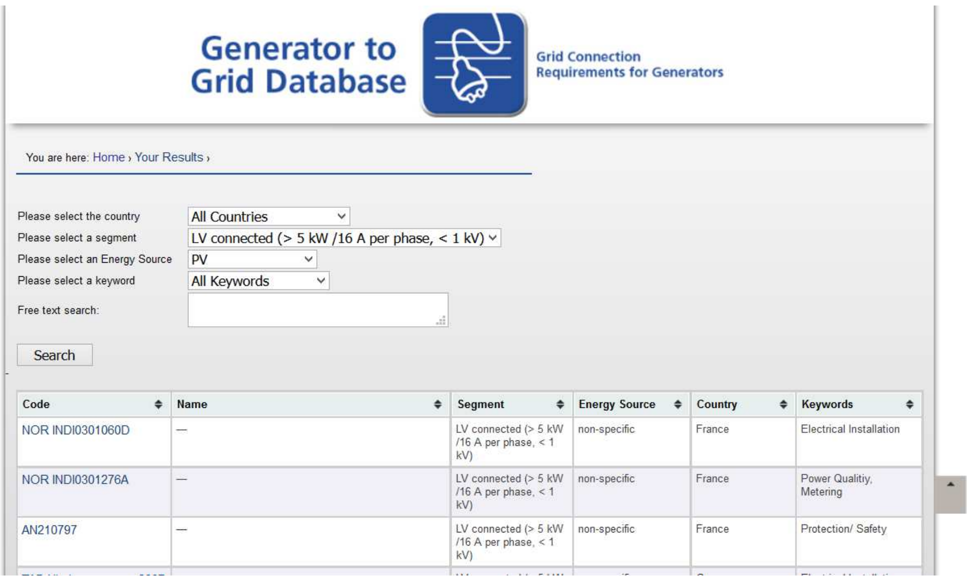


Figure 45: A screenshot of a sample query for LV connected PV standards

Using Germany as a case study, we can also discuss the selection of connection voltage for PV generation. The process is administered by the distribution system operators, which classify applications in terms of the requested connection capacity of the PV system and then decide the appropriate connection voltage based on their practices and taking into consideration two standards:

- The medium voltage directive of the German Association of Energy and Water Industries (BDEW), and
- The VDE 4105 code of practice

[68] http://www.inogate.org/documents/ACR_06GE_Connections.pdf
[69] http://www.gridcodes.der-lab.net/database/databaseSearch.php
[70] http://der-lab.net/

The BDEW medium voltage directive has been in place since January 1, 2009, and is for all power generation plants that feed in on the medium-voltage level (with the exception of plants with a capacity of less than 100 kW nominal power as the latter are governed by the VDE code of practice). The VDE 4105 code of practice has been in place since August 1, 2011, and became binding since January 1, 2012; it affects all PV plants that feed in to the low-voltage grid.

According to VDE-AR-N 4105 "*a general limit of 4.6 kVA per phase applies (and the previous option of feeding in up to 110 percent of this power as a single phase has been dropped). Hence, a maximum plant power of 13.8 kVA results when using single-phase, uncoupled inverters (3 x 4.6 kVA) only. Therefore, at least the proportion of the power exceeding 13.8 kVA must be designed with three-phase or communicatively coupled single-phase inverters in larger plants. Conversely, larger three-phase plants may also be supplemented with single-phase and non-coupled devices as long as their aggregate power of 4.6 kVA per phase is not exceeded.*[71]"

Taken together and for the sake of simplification of the administrative procedures associated with grid connection, PV systems with a capacity of up to 4.6 kVA are expected to be connect via a single phase connection whereas from 4.7 kVA up to 100 kVA the connection should be expected to be a three-phase LV connection. From 101 kVA and onwards the connection will be implemented in the MV network.

A report[72] by the Joint Research Centre (JRC) of the European Commission titled: "Distributed Power Generation in Europe: technical issues for further integration" explains that there is no generally applicable maximum net capacity which can be stipulated as the upper distributed generation threshold. Generators connected to the distribution network with a capacity higher than 100 MW are quite rare in Europe. Distribution networks generally connect generating units with a net capacity up to 20-30 MW, otherwise the connection application is handled by the transmission companies.

3 The framework for building-PV deployment

The global development of the PV technology, the European side of which was described in the first section, has enabled the commercialisation of the technology by reducing costs and increasing efficiency and reliability, as described in section two. Electricity generation from PVs is today a much proven technology with installations ranging from a few kW to utility scale projects of hundreds of MW. While essentially similar, from a technological perspective, building-PV systems either small scale residential or medium scale commercial and industrial ones, needs a different enabling framework from usually larger scale ground mounted utility scale installations. In the rest of the section the specific framework for deployment of PVs in buildings will be presented in more detail.

3.1 Legal & regulatory framework

3.1.1 European framework

The main driver for the development of renewable energy including PV systems in the EU is undoubtedly its climate and energy policy. Addressing the concerns over the climate change and in line with its targets regarding security of supply, the EU has adopted a turn away from fossil fuels and towards energy efficiency and increased use of renewable energy especially in the electricity sector.

[71] SMA AG, Technology Compendium – 3.4 PV Grid Connection (http://files.sma.de/dl/10040/PV-Netzint-AEN123016w.pdf)

[72] http://publications.jrc.ec.europa.eu/repository/handle/JRC43063

The renewable energy Directive 28/2009[73] sets the overall policy framework for the development of RES especially in the electricity sector by providing priority to electricity produced from RES and setting obligatory RES targets for every MS, in order to achieve a European target of 20% RES in total gross final energy consumption by 2020. National policies towards those targets are established according to the National Renewable Energy Action Plans (NREAPs) and are monitored regularly against their intermediate target achievements. According to the latest report of the "Keep on Track" project led by EUFORES[74] most of the MS are on track with their intermediate 2013 target (Figure 19), however as it is stated in the EC's biannual RES progress report[75] the majority is not expected to reach the 2020 targets. As far as PV deployment is concerned however, electricity generation from PV systems had exceeded 2020 target already in 2014.

The 2015 energy and climate strategy[76] for 2030 calls for a more ambitious European RES target of 27% by 2030 while at the same time sets the consumers at the forefront of the forthcoming transition[77].

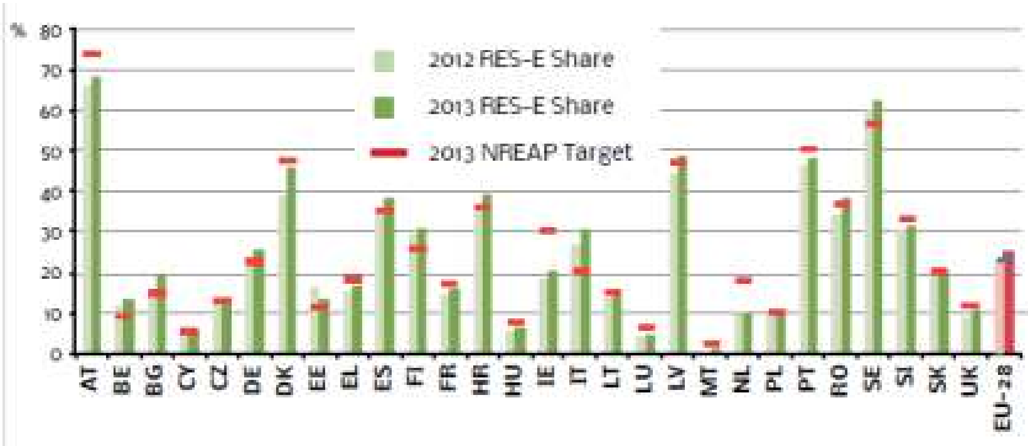


Figure 46 Progress over the NREAP RES-E trajectory as of 2013 (Source: Keep on track project, EU roadmap 2015 report[16])

Of particular importance for building-PVs is that the Directive recognises the importance of local or regional SMEs in achieving the targets (par.3 of the reasoning) and calls for "simplified and less burdensome authorisation procedures" for small and decentralised renewable energy projects "in order to stimulate the contribution by individual citizens" (art. 13, par1, point f).

In addition, the Energy Performance of Buildings Directive[78] calls MS to ensure that by 2020 all new buildings and by 2018 all public buildings will be nearly zero-energy buildings (NZEB), i.e. buildings with a very high energy performance, whose energy needs are "covered to a very significant extent by energy from renewable sources, including energy from renewable sources produced on-site or nearby" (art. 10). Moreover, MS shall take policy actions in order to ensure that renovation of existing

[73] http://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:32009L0028&from=EN
[74] http://www.keepontrack.eu/contents/publicationseutrackingroadmap/eu_roadmap_2015.pdf
[75] http://eur-lex.europa.eu/resource.html?uri=cellar:4f8722ce-1347-11e5-8817-01aa75ed71a1.0001.02/DOC_1&format=PDF
[76] Framework Strategy for a Resilient Energy Union with a Forward-Looking Climate Change Policy, COM/2015/080 final.
[77] At the time this report was being drafted the EC's 2016 Energy Package had not been released yet.
[78] http://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:32010L0031&from=EN

buildings shall result in NZEB. Building attached and building integrated PV systems are interventions that increase the buildings' energy performance totally in line with the overall policy targets.

The EC recently published guidelines for the promotion of NZEB[79] where it emphasises on-site renewable energy production. According to the publication, MS have so far either set specific requirements for the renewable energy contribution to the building's energy needs or used indirect requirements, which can only be met with on-site renewable generation, such as PV systems. In the recommendations, it is stated that "MS are advised to use renewable energy sources in an integrated design concept to cover the low energy requirements of buildings".

A recent report by the EC on the best practices for renewable energy self-consumption[80] focuses particularly on PV systems and further highlights the importance of these applications in shaping the new efficient and sustainable European energy system. The report recognises that even small scale PV systems have reached grid parity for both commercial and residential consumers in a number of MS and highlights the importance of demand response and storage for making the most out of PV self-production systems.

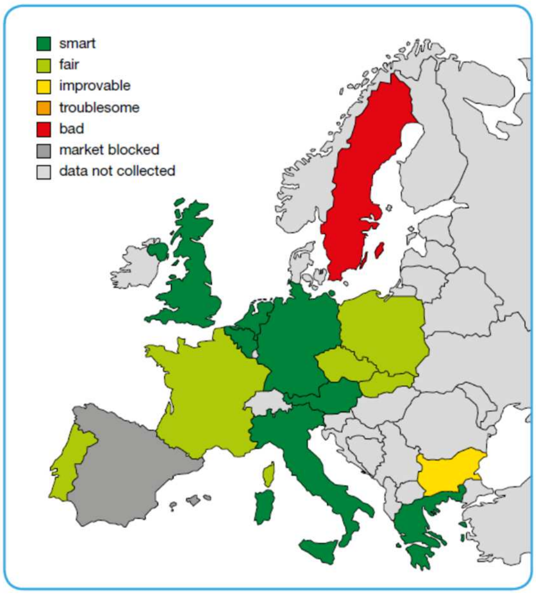
The overall framework is complemented with the provisions of the "Guidelines on State aid for environmental protection and energy 2014-2020" (EEAG)[81]. The EEAG set the rules for the design of support schemes for deployment of RES that are in line with the Treaty on the Functioning of the European Union. It generally provides for the market uptake of RES, adopting the selling of the produced electricity from RES directly into the market and the undertaking of balancing responsibilities by the RES producer, while abandoning the Feed in Tariff scheme. In addition, it demands competitive mechanisms for the determination of the support level from 2017 onwards. However, certain exceptions apply, including small-scale installations up to 500kW, a category that includes most building-PV systems.

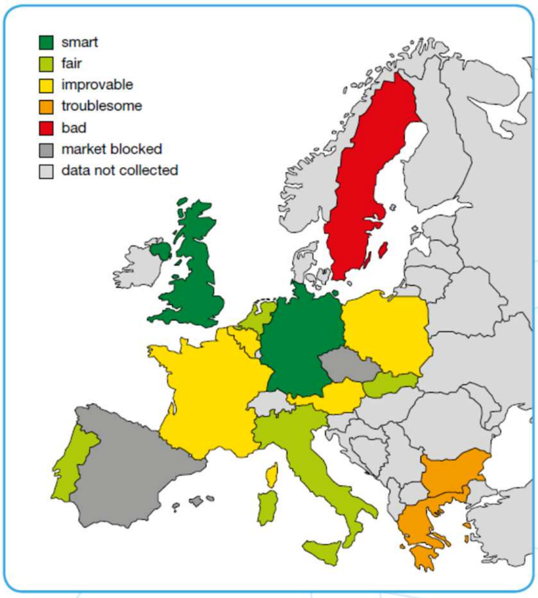
3.1.2 Licensing

While in general a license or permit to produce electricity from any source, including RES, is needed, in most MS the requirements for building-PV systems are often more simple. There is a differentiation of the procedure according to the size of the installation and the configuration, i.e. whether electricity is injected to the grid or not. Small residential installations often require a single permit, if any at all. For larger systems more complicated administrative procedures may apply, often involving some kind of environmental licensing. Special rules and conditions usually exist for monumental areas and a permit from a planning or architectural agency might be necessary in this case. A registration procedure is almost always required regardless of the size of the system, especially if some kind of support is granted. In some MS local or regional specific rules apply.

The RES Directive requires from MS to simplify administrative procedures for RES projects. According to the findings of the PV-Grid project[82] most of the MS have a rather simple procedure for residential PV systems, while for larger systems some administrative barriers have been identified (a scoring of the licensing procedures is shown in Figure 47). The project refers to the status as of early 2014 however, in general, no major changes are expected to have taken place in this sector.

[79] http://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:32016H1318&from=EN
[80] http://ec.europa.eu/energy/sites/ener/files/documents/1_EN_autre_document_travail_service_part1_v6.pdf
[81] http://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:52014XC0628(01)&from=EN
[82] http://www.pvgrid.eu/home.html





Small scale residential systems **Medium size commercial systems**

Figure 47 Scoring of administrative procedures for the development of building-PV systems in EU MS[83]

3.2 Overview of support mechanisms

Although the cost of PV systems has declined rapidly in the last decade and grid parity has been achieved in several countries around the globe[84], the need for support is not entirely eliminated. This need is often related to the difficulties in accessing capital and the different perception of risk by individuals and SMEs. There is a general trend to reduce support to the necessary levels, stemming from the relatively high support provided in the recent past for PV systems. In some cases support is specifically targeted to small scale building-PV systems, in order to enhance the public engagement but also as a way to promote a smart decentralised electricity system.

Almost all kinds of existing support schemes with country and technology specific variations were applied in the EU. It is not unusual to have frequent changes in the framework, either as a mean to foster the development of PVs or as a way to control costs generated by the support mechanisms in place. In certain cases, such as in Spain or Greece, retroactive legal measures were imposed, in order to reduce the very high returns of PV systems. This, however, is hardly a good practice, as a clear and stable support framework is necessary in order to attract and maintain investments. In that sense, the Spanish and the Greek example highlight the importance of attractive, sustainable and robust support mechanisms, which have to be continually monitored in order to ensure their effectiveness and their efficiency.

The support schemes may be roughly categorised in two groups: (a) schemes that are capital cost oriented and focus on the direct financing of a project and (b) schemes whose support targets the electricity produced. A combination of both may also apply in some MS. Apart from national schemes, local or regional programs, often with the aid of EU cohesion funds, may also provide financial support for the development of PV projects. A short description of each scheme's characteristics is provided hereafter.

[83] PV-Grid, Final Project Report http://www.pvgrid.eu/fileadmin/PVgrid_FinalProject_Report.pdf

[84] https://www.db.com/cr/en/docs/solar_report_full_length.pdf (see page 9)

3.2.1 Capital cost based support

3.2.1.1 Investment grants

The coverage of all or certain amount of the investment cost of a system through a grant or subsidy was largely used during the initial state of the development of the PV sector, when costs were still high and non-subsidised investments were economically not feasible. Cohesion funds were often used for this purpose. Those initial schemes, made it possible to start introducing PV systems in a market context where rules for integration of PV had not been developed yet. The investment grants were useful to start up PV markets in many MS helping the policy makers identifying the numerous barriers for their development. Currently PV systems are considered a mature, low cost technology so only targeted grants exist e.g. for SMEs and individuals, covering a part of the investment cost. Some local programmes may also provide limited capital cost support.

3.2.1.2 Soft loans

As the business case of an investment in PV systems becomes more and more economically meaningful, grants are substituted by soft loans, i.e. loans with favourable conditions compared to ordinary commercial loans. Soft loans are used to reduce the risk of the investor and are usually backed by a support scheme on the generated electricity, that provides relevant insurance for the financial institution. Collaterals or other safety provisions are usually needed and may alter the conditions of the loan.

3.2.1.3 Tax rebate schemes

The application of tax rebate schemes is an alternative support for an investment in PVs. The investor receives a part of the capital cost of a realised project as a tax reduction or return within a certain timeframe. This provides a certain amount or risk mitigation, especially for SMEs, while at the same time it reduces the burden for national budgets and distributes the related costs in more years.

Table 7 Overview of capital cost based support schemes for selected MS (Source: RES legal and national legislations)

Member State	Capital cost support schemes
Austria	For projects up to 5kWp a 40% investment grant, with a budget of € 8.5 million for 2016, and up to €275 per kWp for rooftop and 375 €/kWp for BIPV is foreseen.
Belgium	In Brussels an investment support of maximum 80.000€ is foreseen for enterprises depending on the size of the company: • Micro and small enterprises: 40 % of the eligible costs • Medium enterprises : 30 % of the eligible costs • Large enterprises. 20 % of the eligible costs The subsidy can be increased by 5 % if the company is certified EMAS, ISO 14000 or «eco-dynamic enterprise» In Flanders PV installations can benefit from a more generic ecological support scheme that provides up to 55% of investment grant depending on the technology and the size of the company.

	In Wallonia a subsidy is granted for installations up to 10 kW. For the first semester of 2016, the subsidy ranged between € 171.30 and € 209.05 per kWp. An extra bonus up to € 1.6 per kWp is provided for low income individuals. The subsidy is paid annually for 5 years and may be subject to a correction if electricity prices deviate from year to year by more than 10%. The subsidy may be given to up to 12,000 installations per year. Since October 2015, a new support scheme, up to 40%, is available for the agricultural sector.
Germany	Soft loans by KfW are provided up to 100% of the investment costs It is a long-term and low-interest loan with a fixed interest period of 5 or 10 years including a repayment-free start-up period. A fixed interest period of up to 20 years is granted if technical and economic duration of co-financed investment is longer than 10 years. Moreover, a commitment fee of 0.25% per month is charged. Additionally a separate soft loan programme for storage equipment for self-consumption facilities exists
Greece	No capital cost support scheme applies specifically for PV installations.
Spain	No capital cost support scheme applies for PV installations.
France	No national capital cost support scheme is in place. Regional and local schemes are in place. VAT reduction for systems on existing buildings.
Italy	From 2001 to 2006 capital grant up to 75% of installation costs was provided. Since 2013 with the elimination of FiT, household PVs may benefit from the tax rebate system for restoration and renovation works in existing building. The rebate covers 50-65% of total restoration cost, including installation, labour and administrative procedures. The amount is paid back as a tax deduction over a period of 10 years. Total eligible cost is 96,000€
Netherlands	Support through a tax rebate scheme - Energy Investment Aid
United Kingdom	No national capital cost support scheme for PVs is in place. Local schemes exist (soft loans & grants)

3.2.2 Production based support

3.2.2.1 Feed in Tariffs - FiT

A feed in tariff is a predefined remuneration of the generated electricity over a certain timeframe. It usually varies with respect to the technology used, the installed capacity and the location in order to account for differentiations in costs and economies of scale. Normally it is calculated based on the levelized cost of energy (LCOE).

The introduction of FiT support schemes was critical for the development of the PV sector in the EU and wherever it was applied it lead to substantial growth, as it enables a steady and predictable remuneration over the support period. However, regulatory failures, inappropriate monitoring and lack of adjustment mechanisms to account for the significant reductions of the investment cost achieved between 2005 and 2015, led to increased overall costs of the support schemes in many MS.

The FiT scheme is considered in general as inappropriate under the EEAG 2014-2020 and where is still applied in the EU, it has to be substituted by another support scheme, either FiP or quotas. However, small size RES systems up to 500kW may still be eligible for a FiT type of support.

3.2.2.2 Feed in Premiums – FiP

Under a Feed in Premium scheme the producer participates in the electricity market and receives the market price which is supplemented, if necessary, by a premium in order for the total remuneration to reach on average the LCOE levels. Fixed or floating premiums with caps and floors may be applied. The FiP scheme has been adopted by more than ten MS as it is principally in line with the provisions of the EEAG 2014-2020. From 2017 onwards, the scheme has to be complemented with competitive procedures, e.g. auctions, for the definition of the total remuneration levels.

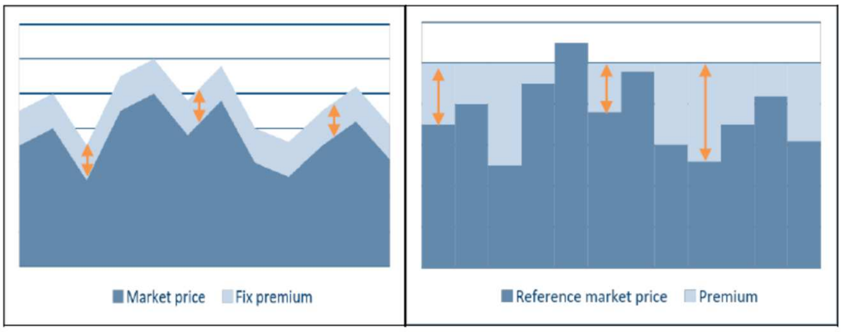


Figure 48 Functionality of fixed and floating premiums (Source: CEER[85])

3.2.2.3 Net Metering

Under the net metering scheme, the electricity produced by a system over a predefined period, e.g. a year, is offset by the electricity consumed by the producer over that period. As a consequence, an economic incentive is created depending on the electricity rates and the overall billing rules of the scheme. In some cases, the total cost of electricity purchase is exempted for the amount of electricity consumed that equals the generated electricity by the system, while in other cases some or all of the regulated components of the electricity tariff, e.g. network charges, RES levies etc, are still paid by the consumer. The netting period is of importance for optimising the system's capacity.

Net metering schemes have been applied for quite some time in some MS e.g. Denmark, Belgium, and are becoming more attractive as they enable the transition to small scale distributed generation. They become the more attractive as the markets move towards parity of prices. However, the large uptake of distributed generation under net metering may create significant distortions to the market[86]. CEER recommends that net metering of self-consumption should be avoided as "*it implies that system storage capacity is available for free, reduces consumers' time-value sensitivity to volatile energy prices and hence undermines efforts to enhance flexibility and to develop a wider demand-side response with consumers playing a more active market role*"[87].

[85] CEER, Key support element of RES in Europe: moving towards market integration, Jan 2016, www.ceer.eu/portal/page/portal/EER_HOME/EER_WORKSHOP/CEER-ERGEG%20EVENTS/CEER_Conferences/CEER_CONFERENCE_2016/Presentations/Session%202%20-%20Finger%20-%20Key%20support%20elements%20of%20RES%20in%20Europe.pdf.

[86] EC, SWD(2015) 141 final, Best practices on Renewable Energy Self-consumption, ec.europa.eu/energy/sites/ener/files/documents/1_EN_autre_document_travail_service_part1_v6.pdf.

[87] CEER Position Paper on Renewable Energy Self-Generation Sep 2016 http://www.ceer.eu/portal/page/portal/EER_HOME/EER_PUBLICATIONS/CEER_PAPERS/Electricity/2016/C16-SDE-55-03_Renewable%20Self-Consumption_PP.pdf

3.2.2.4 Quota mechanisms

The quota support mechanisms rely on the creation of a market for renewable energy (e.g. through Green Certificates) by setting obligations to suppliers of electricity for a certain amount/share of renewable electricity over the total amount of electricity they supply. This leads to a demand of renewable electricity and consequently to an additional value on top of the market price.

Quota schemes are generally characterised by their cost effectiveness as the decision on the optimum deployment of various RES technologies is left to market mechanisms. On the other hand, it bears significant risks for the investor and the financial institutions that often lead to lower rates of RES deployment and suboptimal costs.

Quota mechanisms are still in use in some MS, e.g. Sweden, UK, but in general, there is tendency towards mechanisms that provide more safety for the investors.

Table 8 Overview of production based support schemes for selected MS (Source: RES-legal and national legislation)

Member State	FiT	FiP	Net Metering	Quota
Austria	YES 5kW<P<200kW on buildings and facades	-	-	-
Belgium	-	-	YES Flanders P<10kW Brussels P<5kW	YES Green Certificates
Denmark	-	Residential P<6kW all other rooftop	YES	-
Germany	YES P< 100kW	YES	-	-
Greece	YES P<500kW	YES	YES P<500kW	-
Spain	-	-	YES P<100kW	-
France	YES Rooftop with P<100kW Auction based for P>100kW	-	-	-
Italy	-	YES	YES P<500kW	YES old plants
Netherlands	-	YES P>15kW	YES P<15kW	-
United Kingdom	YES P<5MW	YES P>5MW	-	YES until 2017

3.2.3 Funding of the support schemes

Support schemes constitute a burden to the electricity system that is dealt by national governments in different ways. Capital based support schemes are generally funded through special national or European funds while production based schemes are funded through special charges in the form of levies or taxes. Table 12 provides an overview of the financing methods used in EU MS as reported in CEER's available report on RES support.

Table 9. Overview of financing methods for RES support mechanisms in the EU (Source: CEER[88])

	No support schemes in place	General taxation paid by all citizens	Through specific non-tax levies like PSOs paid by all customers via electricity bills	Other
Austria	x			
Belgium		x		
Czech Republic				x
Denmark			x	
Estonia	x			
Finland				x
France		x		
Germany			x	
Greece				x
Hungary				x
Ireland		x		
Italy				x
Lithuania				x
Luxembourg		x	x	
Netherlands			x	
Norway			x	
Poland	x			
Portugal		x		
Romania	x			
Spain		x		
Sweden	x			
UK		x		

3.3 Rooftop market decision making consideration

The rooftop PV market concerns mainly the household sector, which covers the largest part of buildings, commercial and productive activities, e.g. stores and sheds, and a limited number of agricultural buildings, e.g. stables, warehouses, processing activities. None of the above categories recognises electricity production as an investment priority nor does it represent their core business activity. Those categories are willing to invest into PV technologies only if:

- There is a tangible economic advantage at low risk, where “tangible” is balanced by the environmental driver to switch to renewable sources of energy;
- The procedures to install the system and to cash the benefit do not imply risks, are easy to be processed and are completed within a known period of time;
- There are some other tangible benefits linked to the property the PV system is installed in (facilitation of building permits, tax holidays, etc.).

Incentive mechanisms can be designed for the support of grid connected large size utility scale PV installations, or to be directed to small scale systems to attract investments from sectors that are usually not interested in producing electricity. Depending on the target, the applied policies may result in a high growth in terms of capacity but lower numbers of large scale systems or in a high dispersion of small systems over a higher number of installations. For instance, in Italy 80% of PV installations are small household roof-top systems but they represent only 14% of total installed capacity.

88 C14-SDE-44-03 CEER Status Review of Renewable and Energy Efficiency Support Schemes http://www.ceer.eu/portal/page/portal/EER_HOME/EER_PUBLICATIONS/CEER_PAPERS/Electricity/Tab4/C14-SDE-44-03_Status%20Review%20on%20RES%20Support%20Schemes_15-Jan-2015.pdf

On the whole, whereas the huge and costly incentive programmes of the past years in the electricity sector (as applied in Germany, Italy, Spain) are over, and overall annual PV grid installed capacity is growing at a slower pace if not totally frozen, the rooftop market is still growing, showing an interesting perspective. This is due to a series of reasons:

- Incentives and support schemes for rooftop systems may be scattered on a variety of measures. Rooftop market does not uniquely rely on a single instrument (such as FiT). Rooftop PV market may be promoted by tax incentives and tax holidays, regulatory instruments such as net-metering, building licensing bonus, building obligation quotas or energy efficiency measures;
- Self-consumed electricity value from a PV system is compared with end user electricity costs that have usually almost twice the value of grid price. Instead of grid parity the parameter is retail cost parity.
- Many barriers not linked with the economics of the investment have been removed. Licensing, authorisation and connection rules have been simplified in many countries making PV installation an easy option for the household sector.

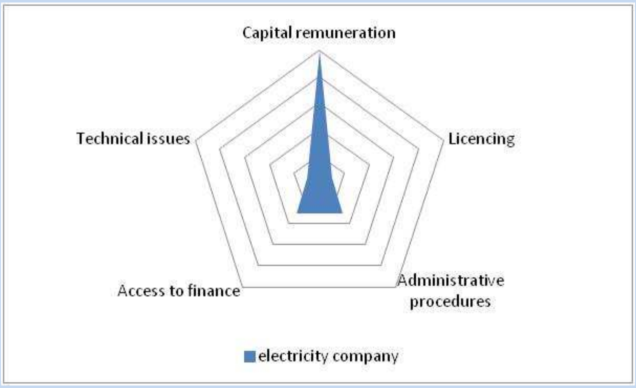
Box 2 below gives an overview of the decision making process for rooftop PV systems.

BOX 2: The decision making process for a PV rooftop installation in household sector

The decision making variables for PV rooftop installation for a family or SME are somehow different from the investment decision of an electricity company. An electricity company mainly values the final capital remuneration of investments. Licensing and authorization issues may be a nuisance but they are taken as ordinary business activities. Financing is usually easily accessed if there are stable market and regulatory conditions and there is little risk connected to technical issues.

For a family, even an attractive remuneration, may not be enough to go through cumbersome administrative procedures, property problems or technical uncertainties. Finance is also not easily accessible if there are no specific products in the credit sectors.

We may graphically represent the decision making process to install/invest in a PV systems of an electricity company and of a family with the following spider graphs where the main variable for a company is final remuneration whereas for a family it is the presence of an overall favourable policy, regulatory and economic framework surrounding rooftop PV systems. Economic considerations are important but much balanced among other variables.



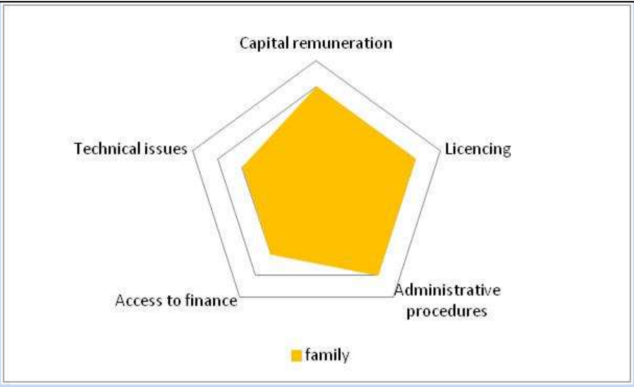


Figure 49 Decision making representation to install/invest in PV system, company vs family

We can then come up with a scheme of the decision making steps for a family in order to have a PV system installed. The scheme will serve as a logic support to research in national policy framework of the variables influencing the sector.

1. Capital remuneration: What is the payback time of my investments? How much will the PV reduce my electricity bill?

Needed information: presence and description of economic incentives; presence of a net-metering option; retail price for domestic sector and other final consumers' categories.

2. Licencing: Do I need permits to install a PV system?

Needed information: What is the licensing procedure in the country in order to become a small power producer? Is there any facilitation in the procedure?

3. Administrative procedures: What kind of procedures do I need to complete?

Needed information: What kind of building permission/authorization do I need? Is there a standardised procedure? Is it possible to install PV in apartment blocks? What kind of agreement with my electricity supplier is needed? What is the procedure to connect the system?

Other possible questions with reference to administrative procedure: Do I have any collateral incentive from installing a PV system, for instance, are there some building charges reduction in case I install PV in new buildings?

4. Access to finance: What are the options to access finance if I want to install a PV?

Needed information: What is national interest rate? What is average interest rate for loans to privates? Are there capital cost support schemes? Is there any public or private programme specifically tailored to PV installation or retrofit works that include one?

5. Technical issues: Can I trust the supplier/installer?

Needed information: What is current penetration of PV in the country? How many small size roof-top systems are installed? Do private individuals have access to a sufficient number of suppliers? Are there certification processes? Is information on certified supplier/installers available?

The collection of above information constitutes the starting point for private individuals, commercial or agricultural SMEs, farmers etc in order to decide whether to install a PV systems or not. This group constitutes the reference target for rooftop mounted installation and policies should exactly address the aforementioned concerns.

3.4 Ownership & business models for roof top PVs

The development of building-PVs in the EU is mostly driven by small-scale installations owned by individuals, SMEs and public bodies (e.g. schools). However, other ownership models have been developed, that facilitate investments, mainly by enabling funding. The legal and regulatory framework is essential for the development of alternative ownership models, that may lead to viable business cases; it is therefore frequently adapted, in order to include new emerging models.

In addition, there is a significant differentiation between residential buildings, especially multi apartment buildings, and commercial and industrial ones. The latter are generally owned by a single entity or legal person, therefore the ownership and business model is merely decided based on financial reasons. In the former case however, ownership issues may constitute a significant barrier and be decisive for the choice of the system's ownership model.

An attempt to provide a general categorisation of the ownership models is depicted in Figure 50. A very first distinction between direct ownership and third party ownership exists. Direct ownership refers to individuals installing a small PV system on their house, companies with medium or large-scale installations on commercial or industrial buildings or public bodies installing PV systems on public buildings. This case is dominant when adequate financing is available or possible e.g. through lending. In a direct ownership case the benefits of a support scheme e.g. FiT or net-metering are mostly used for creating a business case, however self-consumption may also provide enough financial incentives, especially in the residential and commercial sector where electricity tariffs are higher.

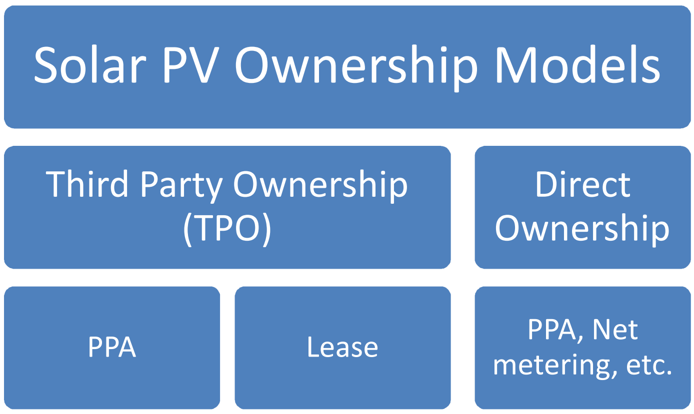


Figure 50: Example legal/regulatory framework: the taxonomy of Solar PV Ownership Models

Third party ownership models are also used in certain MS providing business cases, when funding by the owner of the building is limited or when multi ownership of the building is prohibitive for the realisation of the investment. While third party ownership may take various forms, in most cases it is essentially a renting contract for the use of the building area (e.g. roof, façade etc.) between the owner(s) of the building and the installer. The owner and operator of the PV system, a company or a utility, take advantage of the support schemes in place, in order to formulate a viable business case. Leasing may also be used in this case and is often connected with a transfer of the PV installation to the owner(s) of the building after a predefined pay-back period.

Another interesting case is when the PV system owner acts as an electricity supplier to the building tenants (who may be owners or not).This model may be financially advantageous in the case of building owners with utilities-inclusive renting contracts.

RES Cooperatives or REScoops, is another example of successful ownership models. They are well established in several MS such as Denmark, the Netherlands, Germany, Italy and others. REScoops refer to any group of natural or legal persons that cooperate in the field of renewable energy by e.g. developing new RES systems, selling renewable energy or providing other energy related services[89]. The development of REScoops is in line with the general targets of the energy policy regarding the engagement of consumers in the common energy market. According to RESCoop association, there are nearly 2,400 such cooperatives in the EU, which are active in the field of sustainable energy (Figure 51). A favourable framework is necessary for facilitating the development of new projects by REScoops. Specialised support and funding, usually at local or regional level, is provided to REScoops in some MS. In the case of building-PV systems, a REScoop may develop installations on buildings owned by its members or on rented roofs.

REScoops	wind	PV	hydro	biomass	e-supply	h-supply	other	total
Germany								800
Denmark	250	2	4	1		400		657
Austria	10	30		350				390
Netherlands								110
Sweden								108
Finland								79
Italy (ZEV)		37	26	25	19	21		74
France								60
UK								45
Spain								26
Belgium	6		1	1	2	1		22
Ireland								10
Portugal								6
Croatia								4
Greece								4
Luxemburg								2
Eastern Europe								0
Total Europe								2397

Figure 51: Provisional figures of RES cooperatives in the EU(Source: REScoop 20-20-20)[90]

4 Overview of framework conditions in selected MS

In this section the framework for the deployment of PV systems in buildings is examined in more detail for selected MS so as to identify best practices and lessons learnt. The selection of the MS was made based on the level of the PV market development and especially the building-PVs, the knowledge of the PV market of the countries by the writers, the availability of data and the need to provide an adequate geographical coverage of the EU that is also relevant for the EaP Countries. The decision on the selection of an “adequate” representation of the European Union in terms of building PV framework conditions involved the following key determinants:

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[89] REScoop 20-20-20, Best Practice Report I, 2014, https://www.google.gr/url?url=https://rescoop.eu/system/files/REScoop%2520Best%2520Practices%2520Report%25201.pdf&rct=j&frm=1&q=&esrc=s&sa=U&ved=0ahUKEwjmnOna4cjQAhWCJJoKHVCtAZsQFggTMAA&usg=AFQjCNEHSpjZfmR5aS1UF9RDo5jq6OCzLQ

[90] https://rescoop.eu

- How does rich resource (i.e. solar potential) compare with the robust framework conditions and appropriate support schemes as a key driver for the development of building solar PV? And to what extent the balance between the two above key drivers may be correlated with a balanced development of several PV market segments (i.e. residential, commercial, industrial, and utility-scale)? If we could base our analysis on Figure 5 in an attempt to come up with some answers on the above debate, we should probably do a suitable country selection; In that case, we would then most probably not consider countries such as Romania, Bulgaria, Spain, UK and Portugal where utility scale PV development seems dominant. Equally, in order to ensure a proper representation of all building types we would also rule out countries like Poland or Slovakia where a bias on industrial and commercial buildings can be witnessed. It seems, pursuant to the above selection, that France, Greece, Germany, Netherlands, Austria, Italy, Denmark may comprise quite promising picks in capturing both the resource and policy support aspects while also demonstrating a good balance between different PV market segments.
- The availability of information was also important for this review. Both the bright-side cases but also equally important the shortcomings were interesting for us as long as there was sufficient evidence to support our analysis. For instance, we used the Greek example in explaining the possible surcharge deficit, albeit this very issue was common in other MS that had to retrospectively revise their price promotion mechanisms (e.g. Italy, Spain)
- Last but not least, we found that besides the legal and regulatory provisions, community influence, and ease of financing and innovative business models have an equally important role to play in the success of a support scheme for building PV. We tried to capture this via the review of mainly UK and Dutch practices.

Based on the above we have selected the cases of Germany, Greece, Italy, the Netherlands and the UK to be presented in detail in this section as a representative selection of practices providing interesting insights of various policy and regulatory frameworks that favoured the deployment of building-PV systems[91].

4.1 Germany

The national 2020 target for PV installations in Germany according to the NREAP[92] is 51.7GW. Based on EurObserver data, the total installed capacity at the end of 2015 was already ca.39.7GW exceeding the 2015 NREAP target by some 7.4GW (Figure 52).

According to the Federal Association for Solar Energy 1.53 million PV systems were installed in Germany until the end of 2015[93]. After peaking at round 7,600 MW in 2012 the capacity of new installations continuously decreased. Published data from the national registry[94] indicate that nearly 84% of the PV systems registered in Germany are below 10 kWp and 14% between 10 kWp and 40 kWp, while systems above 1MW represent only 0.1%. In terms of capacity, the distribution is more equally spread among categories with shares ranging between 20-28%. The distribution of the systems in various categories is shown in Figure 54 and Figure 55. However, as depicted in Figure 56 there is a continuous decline in the share of the annual capacity of small systems.

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[91] A significant part of the information is gathered from the ongoing EU funded “PVFinancing” project http://www.pv-financing.eu/

[92] http://www.feed-in-cooperation.org/wDefault_7/download-files/documents/National-documents/Germany/National-Renewable-Energy-Action-Plan-Germany.pdf

[93] https://www.solarwirtschaft.de/fileadmin/media/pdf/2016_3_BSW_Solar_Faktenblatt_Photovoltaik.pdf

[94] http://www.bundesnetzagentur.de/cln_1411/DE/Sachgebiete/ElektrizitaetundGas/Unternehmen_Institutionen/ErneuerbareEnergien/Photovoltaik/ArchivDatenMeldgn/ArchivDatenMeldgn_node.html

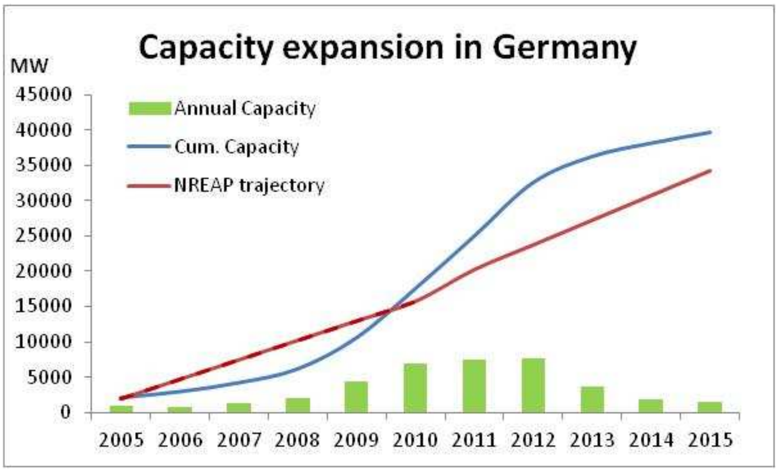


Figure 52: Capacity expansion of PV systems in Germany. The dashed line is a linear regression between 2005 and 2010 figures. (Data: EUROSTAT, German NREAP)

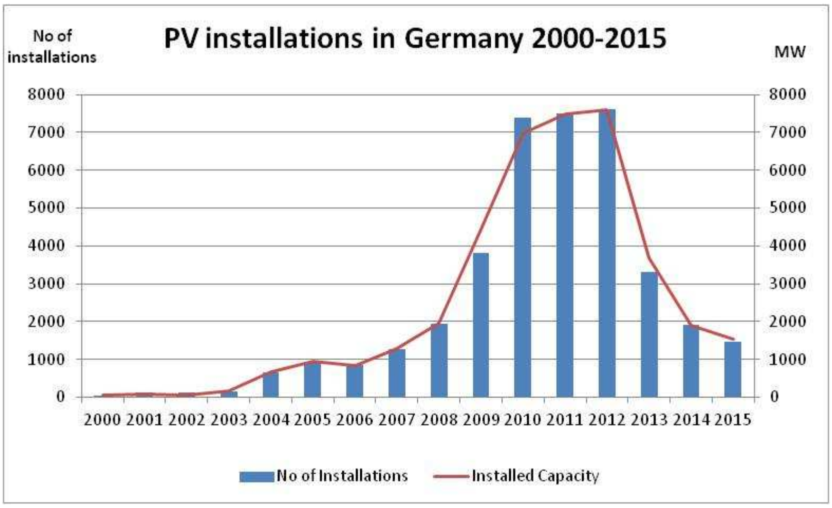


Figure 53: Number of new PV installations in Germany 2000-2015 (Data: EUROSTAT, BSW[34])

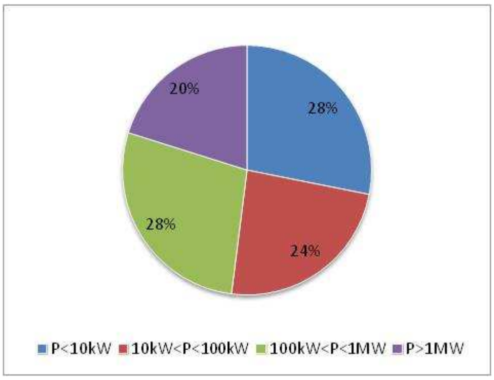


Figure 54: Distribution of registered PV systems per installed capacity - Sep 2016 (Data from BNetzA)

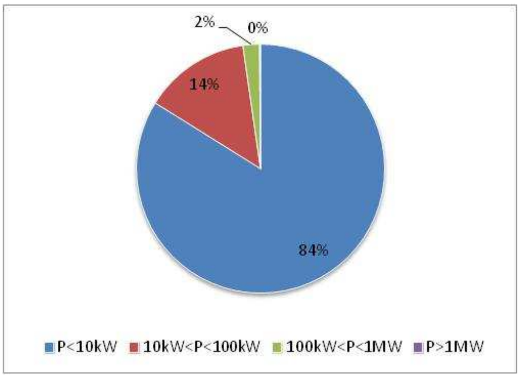


Figure 55: Distribution of registered PV systems per number of installations - Sep 2016 (Data from BNetzA)

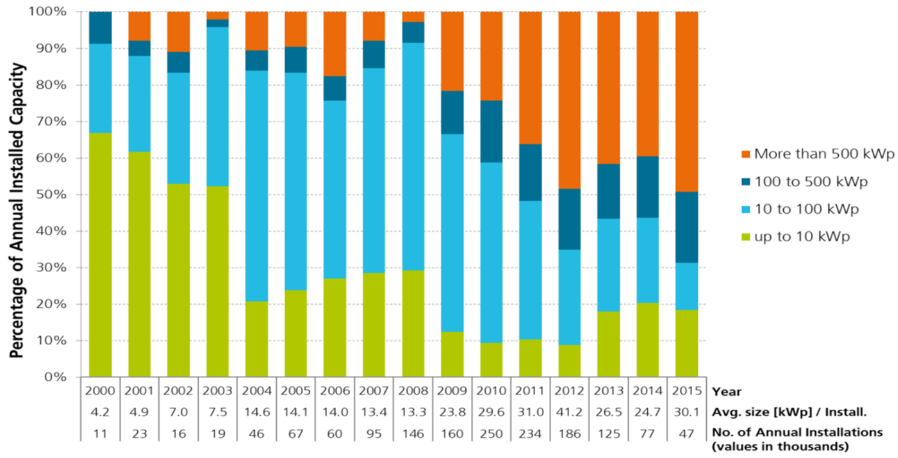


Figure 56: Distribution of annual installed capacity per power rating (Source: FHISE[95])

4.1.1 Licensing

The licensing-permission procedure for PV installations depends merely on the size of the system and may differ among the Federal States (Bundeslaender). General conditions are defined in the National Building Code (Baugesetzbuch, BauGB[96]) where differences exist, according to the exact location of the installation and the proposed configuration, as well as between commercial and non-commercial systems. Small-scale systems usually need no planning permission, except when they are placed in close vicinity of protected areas (e.g. monuments). However, in some States planning permission is needed for systems that exceed the building's planning line (e.g. elevated or tilted roof-top systems).

4.1.2 Grid connection

Technical requirements and conditions related to the connection of PV systems to the grid are set at the relevant national directives[97] and regulations[98]. In addition, grid operators may issue specific connection and operating conditions. For small PV self-producing installations there is a general recommendation by BNetzA to install a bidirectional meter.

In general, RES systems are connected to the grid with priority. The procedures differ among grid operators, but they typically involve a formal application prior to the construction of the system, providing technical details, followed by a study conducted by the grid operator in order to identify possible congestion issues and the optimum connection point, as well as to estimate the relevant cost. For small systems below 30kW, it is legally defined that the building's connection point shall be considered as optimum in the absence of any grid related constraint.

[95] https://www.ise.fraunhofer.de/de/downloads/pdf-files/aktuelles/photovoltaics-report-in-englischer-sprache.pdf
[96] English translation provided here http://germanlawarchive.iuscomp.org/?p=649
[97] BDEW, Richtlinie für Anschluss und Parallelbetrieb von Erzeugungsanlagen am Mittelspannungsnetz
[98] VDE-AR-N 4105, Erzeugungsanlagen am Niederspannungsnetz,

There is a legal obligation for the grid operator to provide a precise time-schedule for the processing of the application (usually several weeks) and the establishing of the connection to the grid. A fee is usually charged for the handling of the application that is however counterbalanced with the grid connection costs. Notably, the PV system owner bears the costs incurred for the connection of the PV system to the connection point, while possible grid reinforcement costs are attributed to the grid operator and collected from the final customers through the network charges.

Lastly it shall be noted that only accredited technicians enlisted in the grid operator's accreditation list may perform connection works.

4.1.3 Support mechanisms

According to the current law on renewable energy (EEG[99]), there are different regulations for the support of PV systems depending on the installed capacity. PV systems on buildings up to 100kW (500kW until December 2015) are eligible for FiT. The level of the FiT changes on a monthly basis and is recalculated quarterly taking into account the current installed capacity and the fulfilment of the relevant target set for the calculating period. EEG foresees an annual target of 2.5 GW of installed capacity for PV installations and a global roof of 52GW after which no further support will be provided. In this respect, the level of the FiT might either increase or decrease accordingly. For each installation, the FiT received is the one valid at the commissioning date and remains the same for a period of twenty years. The following Table 10 shows the FiT for various types of PV systems on buildings for 2015 and 2016. The FiT remains the same from September 2015 onwards due to the slowdown in installed capacity and the deviation from the annual target.

Commissioning Date	Residential roof-top			Non-residential roof-top
	P<10kW	10kW<P<40kW	40kW<P<500kW	P<500kW
Jan 15	12.56	12.22	10.92	8.70
Feb 15	12.53	12.18	10.90	8.68
Mar 15	12.50	12.15	10.87	8.65
Apr 15	12.47	12.12	10.84	8.63
May 15	12.43	12.09	10.82	8.61
Jun 15	12.40	12.06	10.79	8.59
Jul 15	12.37	12.03	10.76	8.57
Aug 15	12.34	12.00	10.73	8.55
Sep 15	12.31	11.97	10.71	8.53
Oct 15	12.31	11.97	10.71	8.53
Nov 15	12.31	11.97	10.71	8.53
Dec 15	12.31	11.97	10.71	8.53
	P<10kW	10kW<P<40kW	40kW<P<500kW	P<100kW
2016	12.31	11.97	10.71	8.53

Table 10: Evolution of FiT in c€/kWh for roof-top PV systems for 2015-2016 in Germany (Source: BNetzA100)

Installations above 100kW (500kW until end of 2015) and up to 1MW for residential roof-top systems and up to 10MW for non-residential systems on buildings and outdoor areas, are only eligible for a

[99] English translation of the 2014 version available here:
http://www.bmwi.de/English/Redaktion/Pdf/renewable-energy-sources-act-eeg-2014,property=pdf,bereich=bmwi2012,sprache=en,rwb=true.pdf

[100]http://www.bundesnetzagentur.de/cln_1412/DE/Sachgebiete/ElektrizitaetundGas/Unternehmen_Institutionen/ErneuerbareEnergien/Photovoltaik/DatenMeldgn_EEG-VergSaetze/DatenMeldgn_EEG-VergSaetze_node.html

FiP. Hence, for systems of this type there is an additional obligation to sell the electricity at the market directly or through a third party (e.g. aggregator). This is also an option for the smaller PV systems up to 100kW. Table 11 shows the evolution of the average remuneration (Target Value) under the FiP scheme for 2015-2016. In order to receive the support either in the form of FiT or FiP the system owners/operators have to register with the Federal Network Agency (BNetzA)[101].

Commissioning Date	Residential roof-top			Non residential roof-top
	P<10kW	10kW<P<40kW	40kW<P<1MW	P<10MW
Jan 15	12.95	12.61	11.32	9.09
Feb 15	12.92	12.58	11.29	9.07
Mar 15	12.89	12.55	11.26	9.05
Apr 15	12.86	12.51	11.23	9.02
May 15	12.82	12.48	11.21	9.00
Jun 15	12.79	12.45	11.18	8.98
Jul 15	12.76	12.42	11.15	8.96
Aug 15	12.73	12.39	11.12	8.93
Sep 15	12.70	12.36	11.09	8.91
Oct 15	12.70	12.36	11.09	8.91
Nov 15	12.70	12.36	11.09	8.91
Dec 15	12.70	12.36	11.09	8.91
2016	12.70	12.36	11.09	8.91

Table 11: Maximum allowable remuneration in c€/kWh for roof-top PV systems under the FiP scheme for 2015-2016 in Germany (Source: BNetzA)

Self-producers of electricity are eligible for reduced RES levy (currently at a level of ca. 63 €/MWh) over the self-consumed electricity. While for self-production systems installed before August 2014 (enactment of Renewable Energy Source Act, EEG2014) full exception from the RES levy was foreseen, from that moment onwards the reduction level was set at 30% for 2015, 35% for 2016 and 40% for 2017[102,103]. Initially, self-consumed energy from PV systems up to 10kW and for up to 10 MWh/year was totally excluded from RES levy payments, however currently the aforementioned reduction rates are valid for this category as well. In addition, self-consumed electricity is not accounted for a number of other regulated charges and levies such as network charges, CHP and offshore levy and electricity taxes that in total may account for a significant amount of the electricity bill.

On the other hand, there is always an opportunity for direct selling of the electricity produced locally to final consumers through a bilateral contract, prior appropriate notice to the grid operator. While the once fully exempted RES levy is payable in this case, all aforementioned exemptions from regulated tariffs and levies apply. These may reach up to ~10.33€/kWh[104] for small households making direct selling from PV systems financially viable in certain cases.

4.1.4 Project financing

[101]BNetzA online registration platform (app.bundesnetzagentur.de/pv-meldeportal/)

[102] https://www.verbraucherzentrale-rlp.de/media226239A.pdf

[103] www.bundesnetzagentur.de/eigenversorgung

[104] Herz S., Selling electricity from PV directly to third parties: opportunities and obstacles in Germany, Feb. 2016, http://www.pv-financing.eu/wp-content/uploads/2016/02/4.Selling-electricity-from-PV-directly-to-third-parties-opportunities-obstacles-in-Germany_SH.pdf

The main financing instrument for PV installation is the long-lasting credit programme for renewable energy (Kredit 274[105]) offered by the German development bank, KfW. The programme is run by commercial banks and offers soft loans to interested investors for up to 100% of the investment and with interest rates as low as 1%, depending on the creditworthiness of the applicant. The repayment period may vary from five to twenty years and there is an interest free initial period between one and three years.

In 2016 the KfW's renewable energy credit line has been supplemented by a similar three year programme (Kredit 275[106]) targeted to financing batteries for PV systems up to 30kW, in order to assist the development of the technology and increase self-consumption uptake. The submission of applications for this programme has however been temporarily suspended since the 30th of September 2016 and for the rest of the year, since applications far exceed expectations. The programme will continue from January 2017 until end 2018.

The installation of roof-top PV systems is also possible through leasing programs. Since third party investments are not eligible for funding under the KfW soft credit lines, this option is of interest for individuals or SMEs that will/cannot benefit from the privileged credit line. Leasing programmes offered by private companies are based merely on the favourable framework for self-consumption, which in combination with the relatively high electricity prices in the household and commercial sector create financially meaningful conditions. Although no data on the level of deployment of this kind of financing mechanism could be retrieved, a number of utilities as well as private companies already offer this kind of financing scheme[107,108].

Interestingly enough crowd funding of PV investments in Germany seems to become more and more popular. Under this scheme, PV system investors receive a part of the investment costs as a loan at interest rates and expenses significantly higher than the low rates of the KfW credit line (rates may vary between 3-8%[42]). In this respect, the scheme serves mainly those projects that are unable to get funds from ordinary bank credit lines.

4.1.5 Ownership and business models

It is unclear whether the operation of a PV system is classified as a commercial activity and must therefore be registered as one or not, and each case shall be treated separately. Based on a decision by the Federation-States Committee in the year 2010, the operation of PV systems on leased rooftops shall be classified as a commercial activity, while on own owned roofs not[52]. However, the regular injection of electricity to the grid and the consequent remuneration is tax-wise treated like a commercial operation. VAT exceptions and other facilitating provisions are foreseen for very small businesses.

[105] https://www.kfw.de/inlandsfoerderung/Unternehmen/Energie-Umwelt/Finanzierungsangebote/Erneuerbare-Energien-Standard-(270-274-275)/#2

[106] https://www.kfw.de/inlandsfoerderung/Unternehmen/Energie-Umwelt/F%C3%B6rderprodukte/Erneuerbare-Energien-%E2%80%93-Speicher-(275)/#1

[107] PV Financing Project, PV Financing Guidelines-Germany, http://www.pv-financing.eu/wp-content/uploads/2016/04/PV-financing_WP3_D3.5_FS-guidelines_GERMANY_EN.pdf

[108] http://www.pv-magazine.de/nachrichten/details/beitrag/entega-verpachtet-photovoltaik-dachanlagen-ab-53-euro-monatlich_100022879/

Apart from self-owned systems, new ownership and business models are often used. The renting of roofs to investors for installing and operating a PV system has emerged and online platforms have been created to facilitate the interesting parties (e.g. http://www.solardachboerse.de/marktplatz/). Even public authorities participate in such a scheme, e.g. the State of Berlin is offering public buildings to private investors for the installation of roof-top PV systems[109].

The development of renewable energy projects through cooperatives is well established in Germany. Germany is one of the most popular EU REScoop countries, with some 812 cooperatives and ca. 165,000 members[110] (Figure 57). According to the energy association of cooperatives (DGRV), 43% of the cooperatives are active in the field of solar energy.

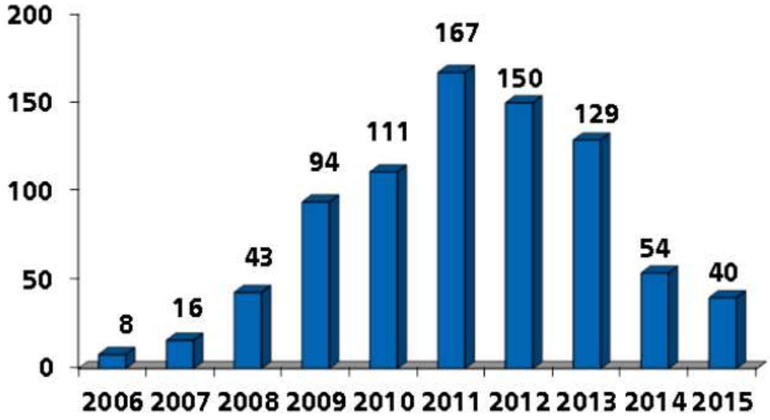


Figure 57: Number of new RES cooperatives in Germany (Source: DGRV[111])

4.2 Greece

Total installed capacity of PV systems in Greece is currently 2.6 GW. This figure is already higher than the national target for 2020, which, according to the NREAP[112], is 2.2 GW. After a small period of rapid growth due to very favourable support measures, the market literally collapsed after 2013, due to changes in the support framework and the general financial and fiscal conditions (Figure 58). Based on annual data from the Association of PV companies, HELAPCO[113], nearly 21% of total installed capacity or 540 MW is attributed to roof top PVs while 15% are small roof-top systems below 10kW.

109 http://www.stadtentwicklung.berlin.de/umwelt/energie/solardachboerse/index.shtml
110 http://www.genossenschaften.de/gesch-ftsmodelle-von-energiegenossenschaften
111 http://www.genossenschaften.de/sites/default/files/Auswertung%20Jahresumfrage_0.pdf
112 http://www.ypeka.gr/LinkClick.aspx?fileticket=CEYdUkQ719k%3D&...
113 http://helapco.gr/statistika-agoras-fwtovoltaikwn/statistika-ellinikis-agoras-2015/ (In Greek)

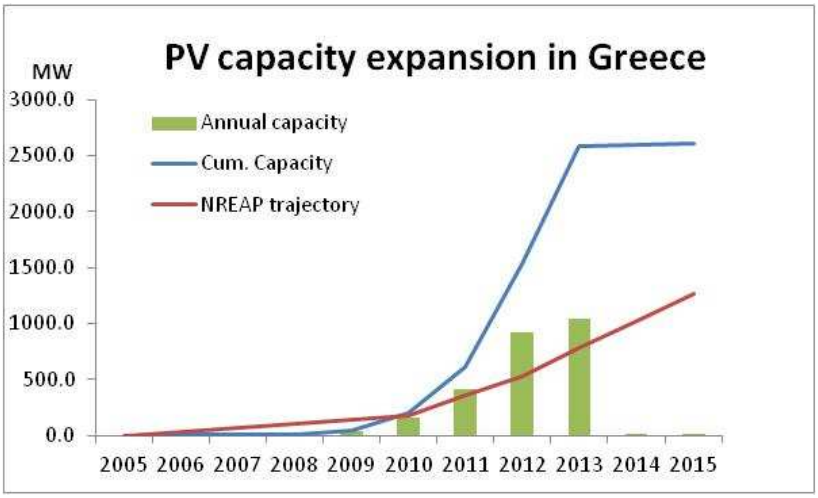


Figure 58: Capacity expansion of PV systems in Greece (Data: EUROSTAT, Greek NREAP, Market Operator[114])

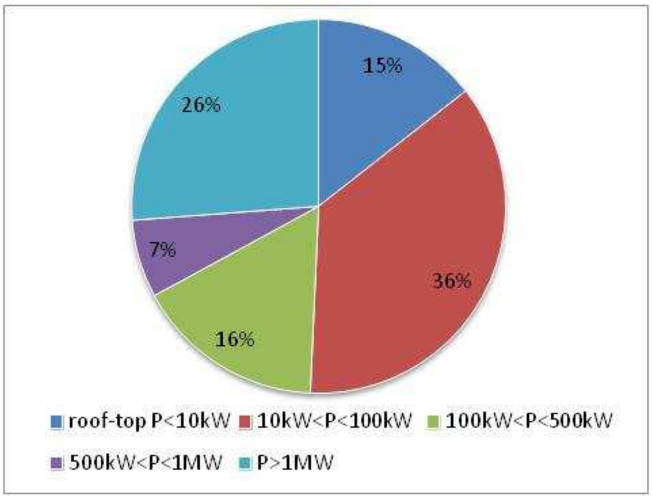


Figure 59: Distribution of PV systems according to installed capacity (Data: HELAPCO)

The overall framework for the support of electricity produced from RES has recently (August 2016) been reformed, in order to become in line with the conditions set in the EEAG 2014-2020. The previous framework was based on a combination of priority in the injection of electricity produced from RES and a favourable FiT guaranteed for 20 years (25 for CSP and for small roof-top systems up to 10kW). Due to the high FiT (especially for PVs) and some regulatory failures, the cost of RES exploded and a series of recursive measures, among which a significant retroactive reduction of FiT in 2014, were implemented,

in order to reduce the final cost for consumers. A special enabling framework for small scale roof-top PV systems up to 10kW was established in 2009 and is described in detail in the next section.

The adoption of the Energy Performance of Buildings Directive in national legislation foresees the retrofit of all public buildings to become NZEB, where this is economically feasible. For the climate conditions of Greece, this reasonably involves the installation of PV systems, where appropriate.

4.2.1 Licensing

A clear licensing framework for PV installations exists in Greece. However, there are several steps and project developers often face long delays, especially for large-scale projects. In general, PV

[114] http://www.lagie.gr/systima-eggyimenon-timon/ape-sithya/miniaia-statistika-deltia-ape-sithya/

projects above 1MW need a generation license issued by the regulatory authority for energy (RAE), and this is valid for large roof-top PV projects as well. Systems above 500 kW also need an environmental permit, which is more strict in terms of its conditions for the case of systems above 2MW. Lastly, for large systems that exceed 1MW, an operation license issued by the regional authorities after the commissioning and the trial operation is also necessary.

For systems on buildings above 100kW, a town-planning permit for small-scale works prior to the initiation of the erection is needed, while for projects below 100kW a notification for the execution of the works to the grid operator is sufficient. Certain conditions and planning rules apply for the construction of rooftop PV installations such as roof coverage limits, allowed height of the PV systems, safety margins etc. According to the new building regulation (2012) the installation of roof-top PV systems on new constructions is allowed as long as the panels do not exceed the building's planning lines. Certain limitations for areas with special environmental or cultural characteristics apply and in this case, an additional permission by the regional Committee for Civil and Architectural Control is needed.

4.2.2 Grid connection

For large systems above 1MW the application for grid connection is submitted to the relevant grid operator, after the issuance of the generation license by RAE. For smaller systems, this application for grid connection is the very first administrative step. A standard application form including technical details of the system is submitted. The grid operator conducts a study and issues the grid connection terms that become final and obligatory after the signing of a connection contract between the system developer and the grid operator. This step involves the payment of all or part of the grid connection costs by the developer.

The grid operator has issued specific guidelines and technical specifications for building-PV systems that are in line with the Regulation for Internal Electrical Installations. A Distribution Network Code is currently valid only for the electrical systems of Non Interconnected Islands.

4.2.3 Support mechanisms

The accelerated development of PV systems was triggered by the existence of a very favourable FiT scheme that was first initiated in 2006. The level of the FiT for PV applications was for a long time very attractive and in combination with various financing opportunities, which also included an additional grant option, leading to extraordinary returns on equity. The failure of the authorities to monitor the procedure and to timely adjust the FiT to the rapid decline of PV system costs, coupled with legislative

provisions that allowed the setting of the tariff for a particular installation way ahead of the time of its actual commissioning, thus neutralising the FiT degression, increased the cost of electricity produced by PV systems dramatically. This finally led to the adoption of retroactive reductions of the FiT in 2014 by ca.25% on average.

The newly adopted legislation on the support of electricity produced by RES (L. 4414/2016) foresees the continuation of a FiT for applications below 500kW. For larger installations a FiP scheme is foreseen, the level of which will be defined periodically through a competitive procedure. Only relatively mature projects in terms of licensing will be able to take part in the auctions. Notably, the cap price for the very first auction expected to take place in December 2016 is set at 94 €/MWh for systems above 1MW and at 104 €/MWh for smaller systems.

The level of the FiT for the small scale PV installations, bellow 500kW, is currently dependent on the average wholesale System Marginal Price (SMP) of the previous year. In 2015 and 2016 the average SMP was 51 €/MWh and 43 €/MWh respectively, which results in very low returns on investment and consequently nearly zero additional installations. A fixed, periodically declining FiT is applied to roof-top PV systems with a capacity bellow 10kW. The applicable FiT level is the one valid on the commissioning data of the system. The following table summarizes the various applicable FiT levels.

<table>
<tr><th rowspan="2">Prices in €/MWh</th><th rowspan="2">Roof-top PV systems with P<10kW</th><th colspan="2">Installations with P>10kW at the Interconnected System</th><th rowspan="2">Installations with P>10kW on the Non-Interconnected Islands</th></tr>
<tr><th>P<100kW</th><th>P>100kW</th></tr>
<tr><td>Feb 2014</td><td>120</td><td rowspan="8">1,2 x av.SMP$_{y-1}$</td><td rowspan="8">1,1 x av.SMP$_{y-1}$</td><td rowspan="8">1,1 x av.SMP$_{y-1}$</td></tr>
<tr><td>Feb 2015</td><td>115</td></tr>
<tr><td>Feb 2016</td><td>110</td></tr>
<tr><td>Feb 2017</td><td>105</td></tr>
<tr><td>Aug 2017</td><td>100</td></tr>
<tr><td>Feb 2018</td><td>95</td></tr>
<tr><td>Aug 2018</td><td>90</td></tr>
<tr><td>Feb 2018</td><td>85</td></tr>
</table>

Table 12: FiT levels for various PV categories in Greece

In May 2015 net-metering was introduced as an alternative mechanism for supporting small scale RES installations, including PV systems. There is a distinction of the beneficiaries between natural or legal entities (e.g. SMEs) and public bodies, non-profit organisations and farmers or farmers' associations. For the first category the system has to be installed at the area (attached to the building or ground mounted) where consumption takes place, while for the second category virtual metering, i.e. remote consumption counter-balancing, and aggregation of multiple meters is allowed. Moreover, while there is a capacity limitation up to 50% of contracted capacity for the first category, the limit is raised up to 100% of contracted capacity for the second. A general capacity cap of 500kW is applicable for all beneficiaries. Special conditions apply for non-Interconnected Islands with lower capacity limits.

The produced electricity is counter-balanced with the electricity consumed on an annual basis upon a 25-year long contractual agreement with the supplier. Any excess of injected electricity is not compensated. Exemptions from regulated charges such as the RES levy (ca. 25 €/MWh for residential consumers) and network charges (ca. 27 €/MWh) are foreseen for the electricity produced by the RES system. Current levels of electricity prices range from ca. 125€/MWh for LV residential and commercial consumers to ca. 67€/MWh for MV consumers, making altogether an interesting case for such an investment. As depicted in the following Figure 60 and, Figure 61 deployment of net metering with PV systems is small yet worth mentioning under current economic conditions. In total out of 573 applications, some 292 systems with a total capacity of ca. 4MW have been installed. Average installed capacity is 13.5kW, while small rooftop systems account for nearly 60% of the installations[115].

[115] Data from Grid Operator http://www.deddie.gr/el/upiresies/fwtovoltaika-kai-alles-ape/fv-apo-autoparagwgous-me-energeiako-sumpsifismo-ne/arxeia-aitisewn

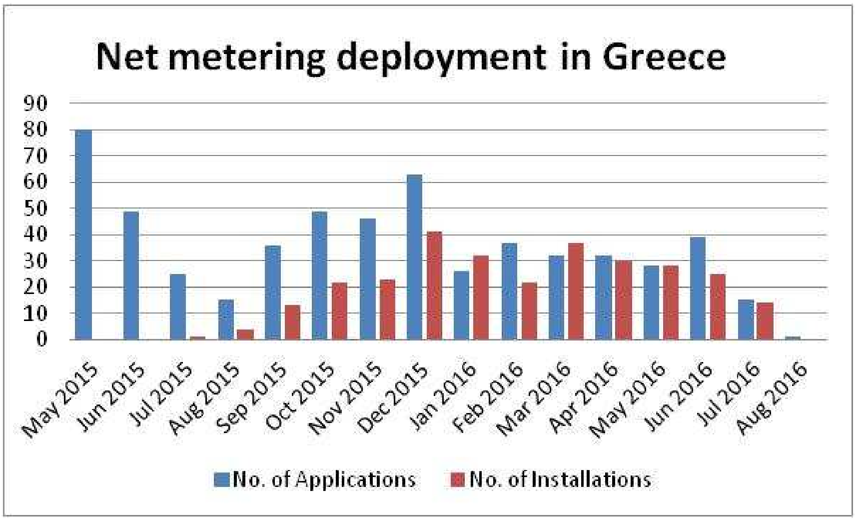


Figure 60: Net metering deployment in Greece in terms of number of applications and installations (Data from DSO)

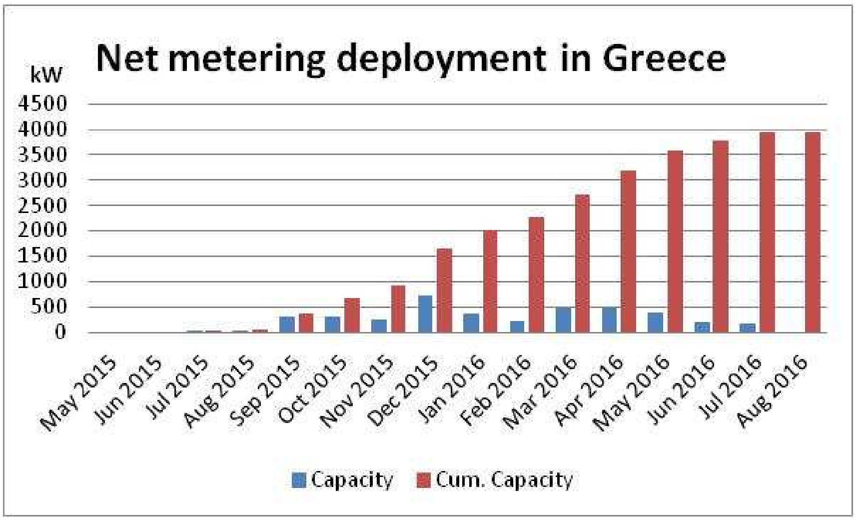


Figure 61: Net metering deployment in Greece in terms of number capacity (Data from DSO)

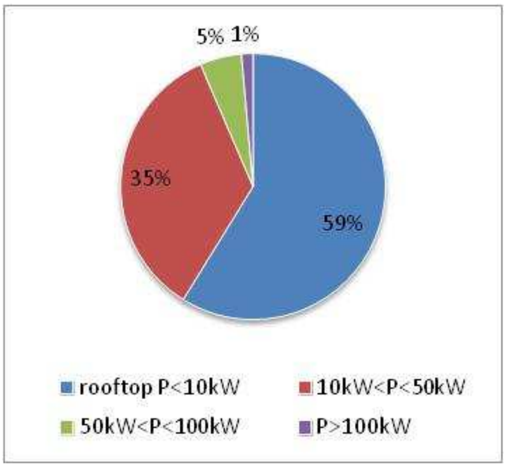


Figure 62: Distribution of net metering PV systems by capacity (Data from DSO)

4.2.4 Project financing

Financing under current fiscal conditions is difficult in Greece. The banking sector has been heavily influenced by the monetary and financial restrictions as well as the structural reforms of the sector and has reduced the provision of loans and credits to the minimum. In any case, the interest rates for most SMEs and individuals are currently around 8% or more, further hindering the realisation of investments.

Grants from structural funds to SME's may theoretically be used for small-scale PV systems e.g. self-consumption or net metering, as a part of a wider modernisation investment. However, conditions are rather strict and the beneficiary needs to provide significant own-capital upfront, while the delays of the grant disbursement are quite long.

4.2.5 Ownership and business models

According to current legislation the selling power to the grid from small scale roof-top PV systems up to 10kW is not considered as a commercial activity, thus the profits are not taxed separately. Operation of larger systems is considered to be a commercial activity and the relevant commercial and tax legislation is applied.

There is no evidence from existing data, e.g. application records from grid operator that any alternative ownership model of PV systems exists in Greece. All of the systems are owned by individuals or legal entities and use one of the available support schemes.

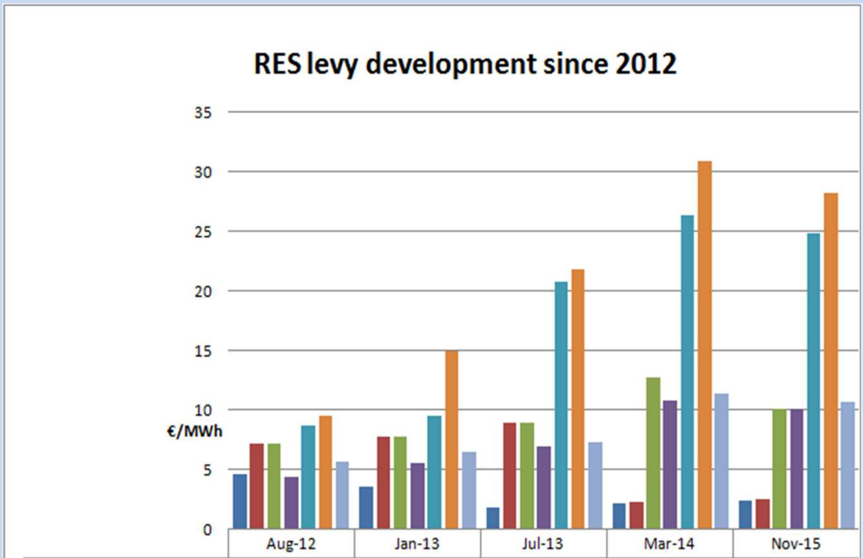
BOX 3: The RES account deficit issue in Greece

The Greek case is an interesting example of the problem of RES support scheme financing that many MS have encountered, especially after the large uptake of PVs. Due to the high investment costs in the initial phase of development, FiTs were set at high levels up to 550€/MWh for small scale roof-top installations. Such Fits along with a favourable investment framework at the time lead to a rapid uptake of the technology as previously shown. More than 90% of the capacity was installed within the period 2011-2013. The average FiT of PV installations in the end of 2013 was 416 €/MWh, while PVs represented 42% of total RES electricity production but 76 % of the total amount of RES support in that year (1,5 billion €).

The RES support cost is to a large extend covered through a RES levy imposed to final electricity consumers. Within the mandatory-pool market framework electricity suppliers are buying the RES electricity at SMP that is generally much lower than the average RES FiT. Consequently, the amount needed to be covered by the RES levy gradually increased. However, since the increase of the RES levy is politically sensitive authorities were reluctant to proceed to the appropriate adjustments. As a consequence the deficit of the RES account in the end of 2011 was 202 m.€ while at the end of 2013 it had reached 549 m.€ with a tendency to reach 1,2 b.€ at the end of 2015 (Source: www.lagie.gr).

BOX 3: The RES account deficit issue in Greece (cont.)

The tax was in force until May 2014. However, the deficit continued to increase leading to a gradual increase of the RES levy and consequently to the introduction of a retroactive reduction of the FiTs for all RES technologies in April 2014. PVs bore the highest burden with an average reduction of nearly 25%. In total the RES levy was increased four times between Aug-2012 and Mar-2014 and was reduced in Nov-2015 as the measures became effective. The following graph shows the evolution of the RES levy for various consumers categories.



	Aug-12	Jan-13	Jul-13	Mar-14	Nov-15
HV consumers	4.58	3.55	1.79	2.23	2.41
MV consumers (>13GWh)	7.17	7.76	8.87	2.32	2.48
MV consumers (<13GWh)	7.17	7.76	8.87	12.77	10.12
Agricultural MV	4.35	5.57	6.97	10.83	10.12
LV Residential	8.74	9.53	20.80	26.3	24.87
LV Commercial	9.53	14.91	21.77	30.89	28.21
LV Agricultural	5.61	6.48	7.33	11.39	10.69

Figure 63. Development of the RES levy in Greece.

4.3 Italy

Italy represents a very interesting case study when addressing the development of PV capacity with specific reference to rooftop installations. The reason for such relevance is to be found in a number of characteristics of the policies and support schemes, currently or formerly in place in the country. There has been a massive support of PVs during past years making Italy the second European country in terms of installed capacity after Germany. With nearly 19GW and some 700,000 installations with an average PV capacity of 27kW, the Italian PV policies have favoured the development of small-scale rooftop installation. Nearly 60% of all installations are rooftop mounted, while 550,000 systems are installed in the domestic sector. This corresponds to a penetration of some 4% of existing building stock.

These results have been achieved by introducing a number of different incentive programs, mechanisms and policy measures over more than two decades now. Italy therefore represents a useful showcase of PV policy options, (capacity based, green certificate, feed-in, net metering, tax incentive, obligation) which may deliver a handful of relevant information when reproducing experiences in other market and contexts, also with reference to different stage of market liberalisation.

In recent years, the main incentive scheme, based on feed-in tariff, was phased out, and incentives remain uniquely on household systems through a tax rebate mechanism. The regulatory framework on household PV installation is now complete in most of its aspects covering economic, technical, administrative and legal issues.

4.3.1 Overview

In the end of 2015 the total PV installed capacity in Italy amounted to 18,892MW distributed in 688,398 installations with an average size of 27.4kW. Small size PV systems, with a rated capacity below 20kW account for over 90% of the total number of plants.

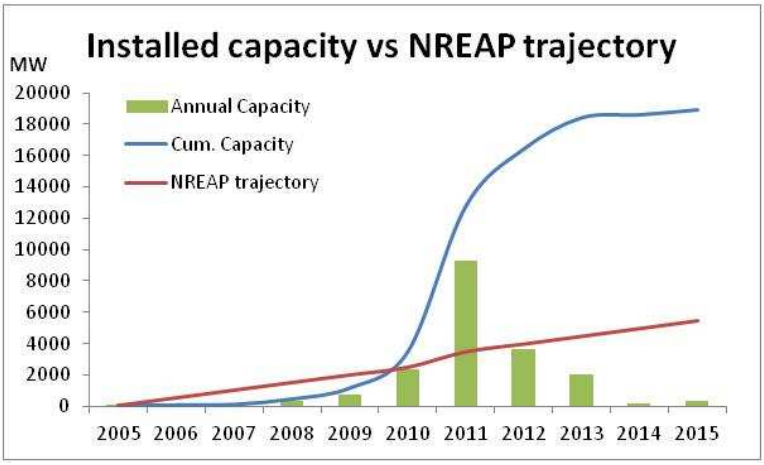


Figure 64: Capacity expansion of PV systems in Italy (Data: EUROSTAT, Italian NREAP[116])

From 2014, onwards and especially in 2015 the market is exclusively based on small size PV systems, whereas installation of larger size systems has seized after late 2014 following the phase out of the FiT incentive scheme. This has resulted in a progressive reduction of the average size of PV systems, which had increased in the previous period due to the installation of larger ground mounted systems (Figure 65). Notably, 97% of the systems are installed at Low Voltage, less than 20,000 are connected in Medium Voltage and only few at High Voltage networks. In terms of installed capacity, MV connections cover 59% of capacity, 35% are in LV and only 6% in HV.

[116] https://ec.europa.eu/energy/en/topics/renewable-energy/national-action-plans

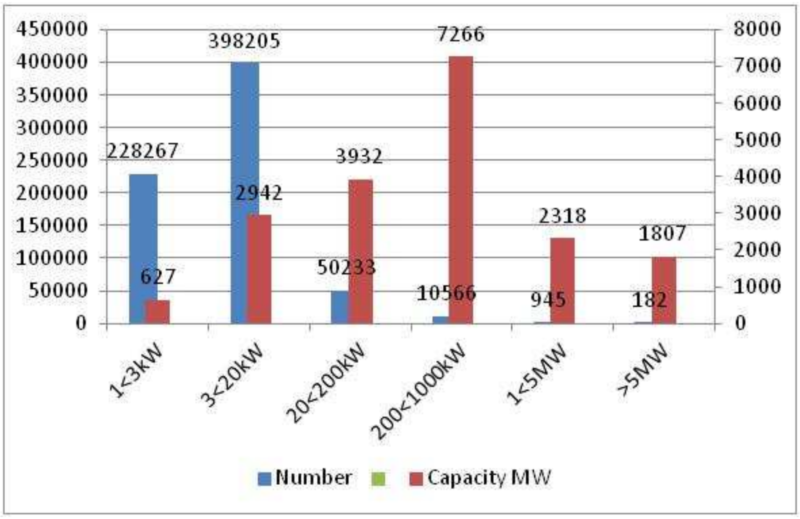


Figure 65: Number of systems and aggregated capacity per size in Italy, data at 31-12-2015 (Souces: Gestore Servizi Energetici. Gse.it)

The following figure (Figure 66) shows the growth of PV system in the Italian market from 2008 to 2015, relative to the number of installations and the overall capacity. In the period 2011-2012, in particular, large size installations were the dominant share of the market thanks to the introduction of a favourable feed-in mechanism as described further on. In more recent years, small size PV has progressively prevailed.

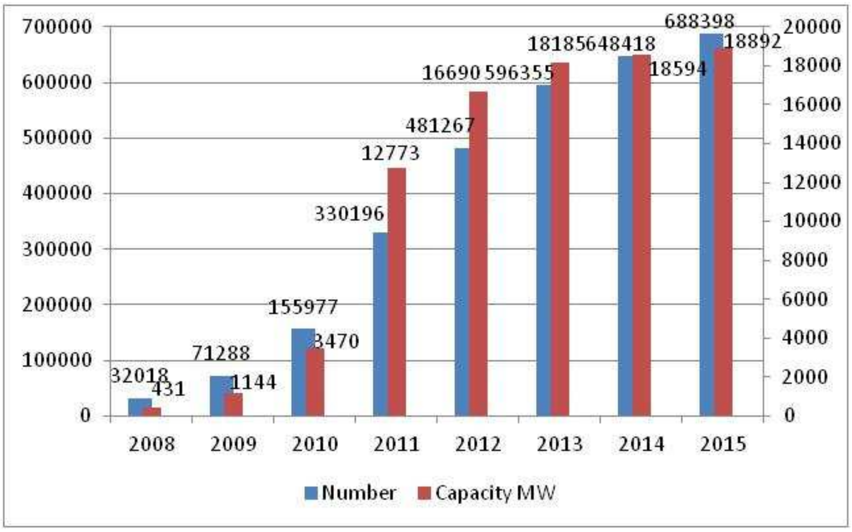


Figure 66: Number of systems and aggregated capacity in Italy, 2007-2015 (Data: GSE)

4.3.2 Licensing

There are different licensing procedures depending on the size, the type and the location of the PV system. Planning procedures have changed over time and have been progressively simplified and harmonised at national level.

In May 2015, a simplified procedure has been introduced by decree in order to facilitate PV installation of small size systems below 20kW installed on buildings and exchanging electricity with the grid through the net metering mode. A single procedure ("Modello Unico") was introduced encompassing licensing, operating permit, grid connection procedure and net metering activation. All procedures are managed by the local distribution company in charge of connecting the system, simply by the submission of a standardised form by the interested party. The submission is done electronically and includes a description of the PV system's characteristics. The DSO shall proceed, within twenty days, to communicate to public administration (the municipality) the installation of the system, open within GSE[117] (Energy Service national Manager) a net metering position and start connection procedures. The system developer has to terminate the procedure once the installation is completed.

The procedure is not limited to PV systems but applies to all renewables systems meeting the following characteristics:

- Installation is done at LV network
- The rated capacity of the installation does not exceed the contracted capacity
- The overall capacity does not exceed 20kW
- The system will operate according to the net-metering rules.

In case the system does not fall within the Modello Unico procedure, there are different licensing steps that need to be followed.

According to Italian Constitution, Title V, the subsidiary level for electricity infrastructure planning and authorisation is shared between the Region and the Central State. This has led, in the past, to different planning procedures in the 21 Italian regions. On the 3rd of October 2010, national guidelines for planning procedures for renewable energy sources were introduced by decree. The central State has introduced minimum standards to which the regional administrations have to comply.

According to the guidelines, PV installations with specific characteristics are classified as building activities without the need of planning permit but only a notification to the municipality. The characteristics are:

- PV system is integrated with the roof shape and inclination
- The size of the system does not exceed the borders of the roof
- The system is installed on an existing building
- Installed capacity does not exceed 200 kW
- The system is not installed within an environmentally or landscape protected area as defined by the Ministry of Built Environment

In this case, three different procedures need to be completed, namely administrative notification to the municipality (proper documentation has to be submitted to the municipality office), connection request to the local DSO and signing a net metering contract with GSE. The main difference with the *Modello Unico* is that all those procedures have to be carried out separately.

In case the systems are not included either to the above definition or to the "Modello Unico", but the size of the system does not exceed the borders of the roof and the overall capacity is still below 20 kW, a declaration of works has to be submitted to the local municipality, which will issue the formal clearance after 30 days, provided that no problem emerges with the project declaration.

4.3.3 Grid connection

[117] http://www.gse.it/en/Pages/default.aspx

Connection rules are included in the abovementioned simplified procedure “Modello Unico” for the eligible systems. In this case, as long as there are no specific impediments, the DSO is obliged to connect the system within 10 working days. Electricity Authority Order 400/2015/R/EEL, sets the connection cost at a 100 € forfeit.

For installations not included in the “Modello Unico” a simplified procedure, the so-called standard procedure applies. This consists of the following three steps:

1) A request for connection quotation needs to be submitted to the local distribution system operator (DSO). The request also includes a 100-500 € payment, depending on the requested connection capacity, in order to initiate the procedure;
2) The DSO has to respond with a connection offer for the requested connection within 20 working days (up to 100 kW) or within 45 days (up to 1 MW);
3) If the connection offer is accepted the applicant has to confirm the works by a payment of 30% of requested connection offer and complete the necessary building works to meet the necessary technical standards.

4.3.4 Support mechanism

There are currently no direct incentives or support schemes for PV installations in Italy. Nevertheless, PV installations in households are eligible for the tax rebate mechanism, which introduces a financial incentive for any significant renovation and restoration works in existing buildings. In addition, net metering option is available for electricity exchange of renewable power systems up to 200kW, with the threshold for PV installations having been recently increased to 500kW.

The tax rebate system consists of the possibility to benefit of a tax rebate for 50% of the installation cost (equipment and installation, including labour and administrative procedure) equally distributed over a period of 10 years. The support mechanism is open exclusively to private individuals and not companies. This is not a specific incentive for PVs but it is a general incentive for any restoration and renovation works carried out in an existing building with PVs being considered as a restoration work.

For other sectors not qualifying for a tax rebate, PV installations may qualify for the issuing of white certificates (energy efficiency title, TEE) in accordance with the energy efficiency incentive mechanism. Each white certificate corresponds to 1 toe of saved energy. White certificates are sold on the market. Their price is currently ranging between 130-170 €/toe but may considerably vary from year to year. PV installations produce energy that is equivalent to roughly 1 TEE/kW per year. The formula to calculate the savings takes into consideration the annual PV expected production, according to the area where the PV is installed (1,282 in the northern regions, 1,852 in the southern). Since TEEs are issued for a period of five years, a correction factor[118], termed durability coefficient, is used in order to take into account the production of the system through all its lifetime (20 years for PVs). Participation in the white certificate incentive scheme is not allowed in parallel to other support schemes except from net metering.

[118] For instance, 1kW in Rome is calculated as: 1 x 1567 x 0,187 x 3,36 (where 3,36 is called the durability coefficient to correct the time of issuing white certificate (5 years) and the lifespan, 20 years

BOX 4: PV support in Italy – Brief overview

Historically, a number of different incentive schemes have been introduced in the Italian electricity market in order to support PV installations.

The first relevant incentive scheme is dated back in 1992. The incentive scheme, named CIP6, was based on the "avoided cost" principle. Independent power producers (at the time the electricity market was a vertically integrated monopoly) running a renewable power plant were paid a feed-in tariff consisting in a fixed part linked to technology capital cost, and a variable part liked to the avoided cost of electricity generation by a new gas turbine plant run by the incumbent. The incentive was able to stimulate early PV market in the country and some MWs were installed. Still the high investment cost of that time limited the installation of PV systems at demonstration level.

The energy law of 1999, on the liberalization of the Italian electricity market also included a reform of the RES incentive scheme. The Decree changed the main Italian incentive scheme from a feed-in mechanism into a green certificate system. An obligation of green certificate quota was set onto electricity producers. The green certificate price, in fact strongly influenced by policy choices, (e.g. setting minimum and maximum prices and introducing a public last reserve buyer in case of CV oversupply) was good enough for some RES technologies, especially wind, but not for PV systems. Again, the incentive scheme resulted in only few PV installations.

From year 2000 to 2006 the Ministry of Environment redirected a limited amount of resources from the carbon tax budget to the support of PV installations on public administration and private buildings. The programme, named "10.000 solar roof", was a capital incentive scheme covering up to 75% of final cost. Rather than achieving the quantitative target, the programme was important since it revealed the need for a specific favourable legislative framework to support rooftop installation. Not only economic incentives, but planning procedures, authorization, financing and other ownership aspects should be tackled in order to succeed in the deployment of building attached PV systems.

The launching of the 10.000 rooftop programme introduced also the possibility to exchange electricity with the grid. In 2000 with order 13 December, n224, the Italian Electricity Authority approved the first regulation to introduce "net metering" in the Italian electricity sector, defining the technical and economic rules. Net metering was made possible through a bidirectional meter that increased the relevant annual cost for consumers to 60 € as compared to the 30 € of an ordinary domestic meter. Net metering was a net compensation between the electricity fed into the grid and the electricity purchased from the grid by the PV system owner. The compensation was based on physical quantities of electricity exchanged. This is to say that each kWh fed into the grid corresponded to 1kWh purchased from the grid, without any reference to the economic value of the kWh (peak-time, base load, season, distribution costs).

In case of a credit by the PV owner (i.e. more kWh injected into the grid than kWh consumed) the amount of kWh is carried forward to the next year. No economic compensation is allowed.

With time, the regulation changed significantly to improve the mechanism and to adapt to the fast changing environment of the electricity sector, the liberalization of electricity market and the management of physical and economic fluxes of electricity. The unbundling between the distribution companies and the electricity selling companies needed a simplification of the net metering management. In addition, the regulatory authority modified the net metering exchanges by centralizing its management within a central body (GSE) and introducing economic criteria to regulate the economic value of exchanges between the electricity fed into the grid and the kWh consumed.

In alternative to "net metering" option a "privileged purchase" option was offered by GSE for those systems willing to sell all amount of electricity produced without opting for net metering mode. "Net metering" and "privileged purchase" option could be combined with the first four feed-in incentive programme. This is to say the feed-in was a premium over alternative options of electricity sales or valorisation. In the fourth and fifth feed-in incentive programme the incentive included the purchase of electricity by GSE.

Eventually in 2007 a specific feed-in incentive scheme was launched named "conto energia". The first "Conto Energia" was introduced by Decree 28th July 2005 amended by Decree 6th February 2006 while the other four programmes were introduced on 19th February 2007, 6th August 2010, 5th May 2011 and 5th July 2012 respectively. All programmes were based on a basic FiT, guaranteed for 20 years and introduced premiums for partially and fully roof integrated systems as well as the removal of asbestos roof when installing a PV system. In 2013 a decree was issued that introduced the suspension of the programme once the public expenses would reach 6,7 billion €. The last PV plants supported under "Conto Energia" were installed in 2014.

The success of Conto Energia was the mobilisation of private capital in the financing of PV installation. This has led to a distribution of systems, especially in the domestic sector, which is not necessarily related to the most efficient collocation of the system. Income and population patterns, and public administration efficiency have contributed to the final distribution of solar installation in a relevant manner.

Table 13 Results of "Conto energia" programme 2006-2014 (Data: GSE)

Conto energia	Number of systems	Capacity MW	Annual cost m.€	Cost per MW m.€
1st	5726	163	95	0,58
2nd	203767	6791	3270	0,48
3rd	38608	1566	648	0,41
4th	203301	7600	2.468	0,32
5th	78840	2094	216	0,10

4.3.5 Project financing

The business model of a standard 3kW household solar system shows a payback period which significantly changes, according to the location of the system and the ratio between produced and self-consumed electricity. As an example, a 3kW system in northern Italy with a 30% self-consumption under the net metering scheme and receiving 50% tax rebate has a payback period of 7-8 years.

During the “Conto Energia” programme the credit institutions were eager to finance installations of PV systems given the favourable incentive schemes and the low risk attached. The companies installing PV systems were offering technical and financial packages and the final consumers were only paying their reduced electricity bill. The credit institutions directly cashed the feed-in incentives and a direct procedure was established between GSE and the credit institution to directly pay back the loan, thus reducing any risk by the bank. Presently, this option is still valid for net-metering quantities but the economic value and the amount of electricity is less certain.

4.3.6 Ownership and business models

The fiscal status of PV production differs according to the size of the installation and the operating conditions. For systems, up to 20 kW under the net metering scheme, no taxes have to be paid by final users on the amount of electricity exchanged, whereas for the quantity of electricity sold within the 5th feed-in mechanism, this becomes personal income and is taxed appropriately.

Larger systems are considered as electricity producing units and all taxes apply to the amount of electricity sold. In addition, in case of self-consumption, by the owner of the system, consumption duties which would have been paid by purchasing electricity from the grid are charged. A VAT of 10% is due on electricity sales of PV systems owned by commercial and industrial activities or private individual with a VAT position. The installation of PV systems on residential buildings is considered by the Italian tax authority as a building renovation, and as such a reduced VAT of 10% applies, instead of the standard 22%. Local council taxes may also be introduced by local municipalities for PV installation above 20 kW. In terms of capacity, more than 50% has been installed in the industrial sector, following commercial sector, households and agriculture.

Ownership has been a complex issue in case of multi flat buildings. In this case, initially, the authorisation to have a PV system installed on the roof had to go through condominium management rules. According to the building code when there is a substantial modification or change of property of the common area of a condominium, it is necessary to reach full agreement among apartment owners. This made it extremely difficult to install PV systems either for the use of the condominium (common services, lights, lift, water pumping), or for the use by a number of a single apartment (e.g. by allowing the installation on a portion of the roof). Over time, legislation was refined in order to include PV installation in the list of works that can be concluded with 51% agreement of condominium ownership and to allow for a portion of roof to be allocated for use by a single apartment, without modifying property rights.

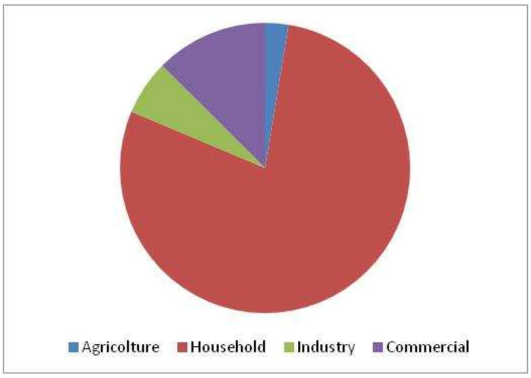


Figure 67: Number of installation per final user category, 2015 (Data: GSE)

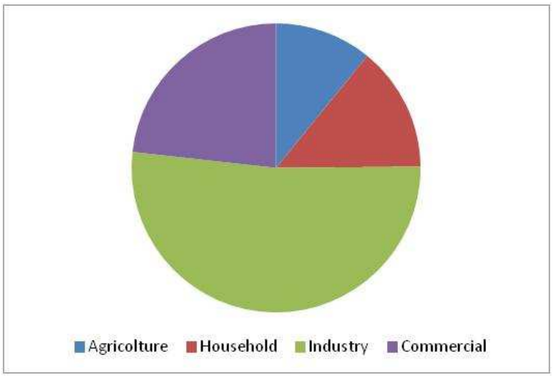


Figure 68: Capacity of installation per final user category, 2015 (Data: GSE)

According to electricity market rules, though, the installation of a PV system on multi apartment buildings may only be used for supplying common services selling any excess of electricity to the grid and not for supplying individual apartments in the block. An additional complication, stems from the fiscal rules since any annual income exceeding 36,000 € has to be included in the tax declaration, thus creating an extra difficulty in case of common PV systems.

Under current provisions, a large portion of the population has no access to national incentives. This may be due to lack of financial access in order to install the system in the first place or to other constrains of administrative type. Usually people living in large buildings with several flats, people renting houses, or simply people with an inappropriate roof e.g. due to shadowing, may not benefit from PV incentive.

In order to overtake some of these difficulties a number of cooperatives were inaugurated with the purpose of installing common PV systems. The principle was simply to share the costs and the opportunities offered by the incentive schemes in order to install a PV system. According to the electricity market rules, direct selling of the electricity to more than a single consumer is not allowed. Some RES cooperatives have been working in conjunction with the public administration. In such cases public administration bodies, e.g. municipalities, that are unable to finance the installation of a PV system, cooperate with private individuals that are eager to invest in the PV sector but have no possibility to install a system due to unavailability of space. In this case, the cooperative finances the installation of a PV system onto a public building, e.g. an office or a school, receiving the relevant FiT and the public institutions pays a bill to the cooperative for the electricity consumed. The model has been limited to few cases at national level, given the complex administrative arrangements needed to complete the agreement.

4.4 Netherlands

Total installed PV capacity in the Netherlands is currently ca. 1.5GW[119], far greater than the technology's trajectory according to the NREAP[120] (Figure 69). Capacity expansion shows a more conservative yet steady growth unlike most of the MS. This is due to the fact that the sector mainly depends on small scale residential and commercial installations (see Figure 5 above) rather than utility scale systems and a steady enabling framework is established. Surprisingly, data on the actual breakdown of PV systems in various categories does not exist, and according to IEA-PVPS report,

[119] Data on PV capacity for the Netherlands differ. According to EUrobserver total capacity in 2015 was 1405MW, while the National Bureau for Statistics (CBS) provides a higher figure of 1.485MW.

[120]Available at https://ec.europa.eu/energy/en/topics/renewable-energy/national-action-plans

this is partly attributed to the high rate of non-registered small scale systems that are favoured by the net-metering scheme or used for self-consumption, due to the high level of electricity prices[121]. According to the annual report on RES from the National Bureau for Statistics (CBS)[122] there are estimations of some 220 thousand systems being installed in the Netherlands in 2014 with an average capacity of 4.7kW per installation. Information from the PV-Financing database refers to an average capacity of 3kW for residential systems[123].

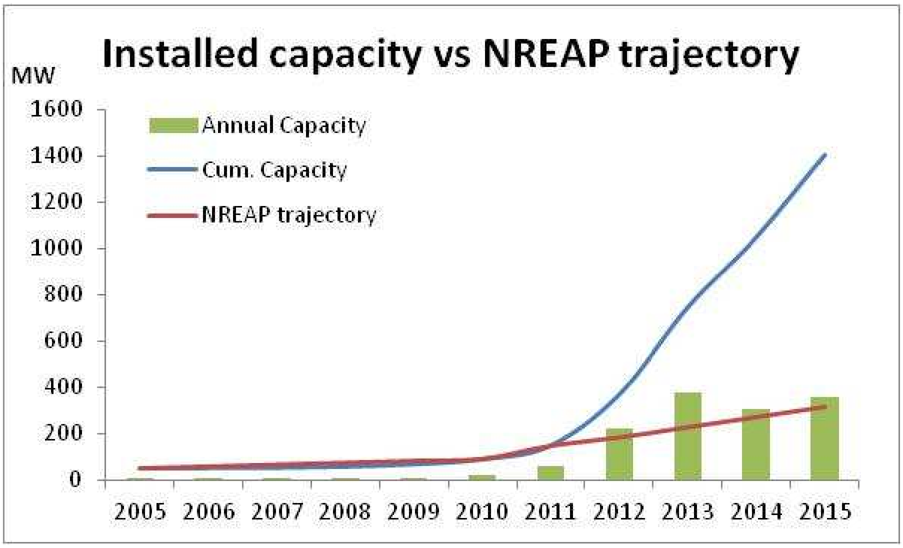


Figure 69: Capacity expansion of PV systems in the Netherlands (Data: EUROSTAT, EurObserver, Dutch NREAP)

4.4.1 Licensing

The installation of PV system on residential buildings, with the exception of the, so-called, listed buildings e.g. monumental ones, is generally a straightforward process that includes literally no permit, if certain planning rules are followed (panel elevation over roofs, tilt angle etc). For listed buildings, a regular environmental permit is required. Apart from the national planning law and guidelines[124], regional and local planning rules and guidelines exist for PV systems on listed buildings[125]. Two important technical guidelines, including electro-technical, as well as architectural aspects, have been published by the Building Services Research Institute (ISSO)[126].

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[121] IEA-PVPS, National Survey Report of PV Power Applications in the Netherlands-2013, http://iea-pvps.org/index.php?id=93

[122] CBS, Hernieuwbare energie in Nederland 2014, Mar 2105 https://www.cbs.nl/nl-nl/publicatie/2015/40/hernieuwbare-energie-in-nederland-2014 CBS, Hernieuwbare energie in Nederland 2014, Mar 2105 https://www.cbs.nl/nl-nl/publicatie/2015/40/hernieuwbare-energie-in-nederland-2014https://www.cbs.nl/nl-nl/publicatie/2015/40/hernieuwbare-energie-in-nederland-2014

[123] PVFinance project, factsheets for Netherlands on http://database.pv-financing.eu/en/database/pvgrid/netherlands/national-profile-9/residential-systems/2536/rooftop-pv-systems-on-non-listed-buildings-1.html .

[124] http://cultureelerfgoed.nl/sites/default/files/publications/ven_2015_zonne-energie-plannen_en_monumenten.pdf

[125] e.g.for Utrecht https://www.utrecht.nl/fileadmin/uploads/documenten/3.ruimtelijk-ontwikkeling/Erfgoed/Energie/Richtlijnen_plaatsing_zonnepanelen_op_beschermde-monumenten_en_in_beschermde_stads-_en_dorpsgezichten.pdf, for Groningen https://gemeente.groningen.nl/sites/default/files/54273-richtlijnen-voor-het-onroerend-erfgoed-groningen-2016-nummer--5556726.pdf

[126] http://kennisbank.isso.nl/docs/kleintje/zonne-energie/2016/13

All small-scale PV systems that inject power to the grid shall be registered at the grid operator. Medium sized commercial applications with capacity above 50kW that are supported under the Sustainable Energy Production Incentive (SDE) need to be registered at the certification authority[127]. Both registrations may be performed electronically.

According to information obtained by the Dutch Association for Solar Energy (Holland Solar) there are several local initiatives that act as PV systems' development facilitators.[128]

4.4.2 Grid connection

In general, installers of PV systems are certified by ISSO ensuring that all relevant works will be conducted in accordance with the applied rules and guidelines. For small systems, a registration form (notification or readiness) is submitted to the grid operator who then verifies the system's technical standards. For systems with larger rated capacity that might need to be connected at a distance from the building they are installed, the grid operator undertakes the necessary works.

4.4.3 Support mechanisms

The support system in the Netherlands was generally less ungrudging than those in other MS and followed a more carefully monitored path. Consequently, the Netherlands gained the benefits from the cost reduction of the technology without creating a heavy burden from large subsidies of the initial expensive phase of PV development. Hence, the growth in PV capacity has not sunk as in other MS, but continues to develop more or less steadily.

After an initial successful period of investment grants, followed by a period of small growth for PVs through the MEP and OVIMEP (Environmental Quality of Electricity) subsidy, a new scheme was introduced in 2008 (Sustainable Energy Production Incentive, SDE). The scheme consisted of an annually calculated FiT the level of which was dependent on the evolution of the natural gas prices; the higher the prices of natural gas the lower the FiT. An annual cap over the total support provided by technology was introduced that prevented the uncontrolled deployment of the still quite expensive PV systems. From 2012, onwards a technology neutral reverse auctioning scheme complemented the existed scheme renaming it to SDE+ and from 2014 onwards the FiT was substituted with a FiP. The cost reductions that had already been achieved enabled the deployment of PV systems through this mechanism.

The scheme is focused on SMEs and other legal entities and led to the installation of 48 MW in 2013, 137 MW in 2014 but only 1 MW (out of the 357MW) in 2015[65]. According to Holland Solar some 3000 PV projects have been qualified for SDE+ support in 2014, however as the majority (~80%) refers to projects below 500kW, there is a current bank financing difficulty with these projects, due to lower expected returns, resulting in a possible significant failure of the auction process.

[127] PVFinancing project, factsheets for the Netherlands at http://database.pv-financing.eu/en/database/pvgrid/-a909eac30e/national-profile-9/commercial-systems/2547/-1/-6/6.html#6

[128] http://www.hollandsolar.nl/home.html

In 2011, the net metering scheme was introduced that is until today the main support scheme for small size systems up to 15kW at grid connection limited to 80A and annual production up to 5000kWh. From 2014 onwards, the production limit was abolished, while common electricity consumption in multi-house buildings became eligible for netting (projects belonging to associations are however exempted from this provision). The scheme provides good returns mainly due to the high electricity rates and taxes[129] for domestic consumption that together are about 230€/MWh. The scheme is foreseen to be reviewed starting from 2017 but any modification will enter into force from 2020 onwards[39]. This long term commitment to the net metering scheme offers a steady environment for further development of building-PV systems.

In addition to the aforementioned schemes, support is also provided through tax exemptions and reductions. Currently PV system owners may reclaim the VAT imposed on the cost of the PV system (maximum allowable reclaim is 1,345€) and on the electricity injected to the grid following the provisions of the rules for SMEs.

In the case of cooperation or (home)owners' associations a tax discount, currently of the order of 10.7€/kWh (12.18€/MWh with VAT),[130] is also foreseen for the electricity injected to the grid and netted over the consumption of small final users within a certain territory (postcode cluster). With this provision, even individuals or legal bodies like SMEs without suitable space may be engaged in electricity production from a RES system, including PV systems. There is a total consumption cap for this scheme set at 10,000 kWh per user. Notably, a PV system owner who consumes more than the system's production may become part of a cooperative and benefit up to the rest of the consumption.

A tax rebate at a level of up to 58% of the investment cost is also available for companies that apply for the so-called Energy Investment Allowance (EIA). The long lasting scheme is applicable to projects of more than 25kW of installed capacity and for a maximum investment cost of 750 €/kW calculated for the part of the capacity above 25kW. While previously allowed, from 2014 onwards the EIA cannot be applied in combination with the SDE+ mechanism.

Other tax reduction opportunities may be applicable to PV system investments as well, e.g. related to the SMEs VAT exemption or to the removal of asbestos containing roofs.

4.4.4 Project financing

A series of capital cost subsidy schemes were introduced in the past allowing the PV market to emerge and grow. Currently only the tax rebate schemes described above are applied. If not totally provided by own sources the financing of a PV investment involves typically a bank loan. An interesting alternative would be for the PV developer to integrate the PV system costs in an existing mortgage in order to benefit from additional tax deduction of the interest.

[129] Apart from normal taxation electricity taxes in Netherlands also account for the funding of the RES support schemes.

[130]Hier Obgewekt, TOELICHTING Beslisboom Zonneparken, http://www.hieropgewekt.nl/sites/default/files/u20232/toelichting_beslisboom_zon_versie_2.0_-_datum_15_feb_2016.pdf Hier Obgewekt, TOELICHTING Beslisboom Zonneparken, http://www.hieropgewekt.nl/sites/default/files/u20232/toelichting_beslisboom_zon_versie_2.0_-_datum_15_feb_2016.pdfhttp://www.hieropgewekt.nl/sites/default/files/u20232/toelichting_beslisboom_zon_versie_2.0_-_datum_15_feb_2016.pdf

A number of provincial and municipal subsidy schemes are however available, facilitating the implementation of projects. For example in Gelderland a civic scheme has been established that offers up to 25% of the investment costs to cooperatives and associations with more than 50 participants for the realisation of RES projects[131].

Crowdfunding is also becoming a popular way of financing, especially for cooperatives. Almost 20% of the PV projects that have been realised by cooperatives have used this way of financing.

4.4.5 Ownership and business models

The owners or users of the buildings typically own most of the building-PV systems. However, other forms of ownership and business models are being developed e.g. leasing of PV systems or direct selling to local users.

Cooperatives have traditionally been active in the Netherlands in developing RES projects, especially wind energy ones, hence this institution is well established. According to the Local Energy Monitor for 2015, published by the knowledge platform for local sustainable energy initiatives (HIER opgewekt), some 220 cooperatives exist in the Netherlands, of which 201 are local cooperatives and 35 project related cooperatives. The members of these cooperatives are estimated at nearly 40,000. Since 2013 the number of local and project related cooperatives has increased due to the favourable framework and have substantially contributed to the development of PV projects acting either as initiator, developer, administrator, financier and/ or owner. At least 98 collective PV projects have been realised totalling some 6.7 MWp of installed capacity.

4.5 UK

PV installed capacity in the UK is currently over 11 GW[132] far beyond the NREAP target for 2020 (Figure 70). The UK market was the leading market for PV deployment in the EU and within the top markets worldwide for the last three consecutive years driven by a very favourable framework. The once anaemic PV market boosted after the introduction of FiTs in 2010 and fully expanded after the introduction of a comprehensive strategy for PV deployment in 2013 that improved further the overall framework. The extraordinary growth that followed and the consequent increase of the costs for support led to the undertaking of preventive measures that included significant reduction of the FiT.

Nearly 900,000 systems were installed in the UK as of August 2016, the vast majority of which consists of small-scale domestic installations up to 4 kW. In terms of capacity however larger commercial or utility scale systems dominate (See Figure 71). The average capacity per installation is 12.4 kW.

[131]HIER Opgewelt, Lokale Energie Monitor 2015, https://www.hieropgewekt.nl/sites/default/files/u20232/lokale_energie_monitor_2015_-_uitgave_januari_2016.pdf HIER Opgewelt, Lokale Energie Monitor 2015, https://www.hieropgewekt.nl/sites/default/files/u20232/lokale_energie_monitor_2015_-_uitgave_januari_2016.pdfhttps://www.hieropgewekt.nl/sites/default/files/u20232/lokale_energie_monitor_2015_-_uitgave_januari_2016.pdf

[132] Aug 2016, data from DECC https://www.gov.uk/government/statistics/solar-photovoltaics-deployment

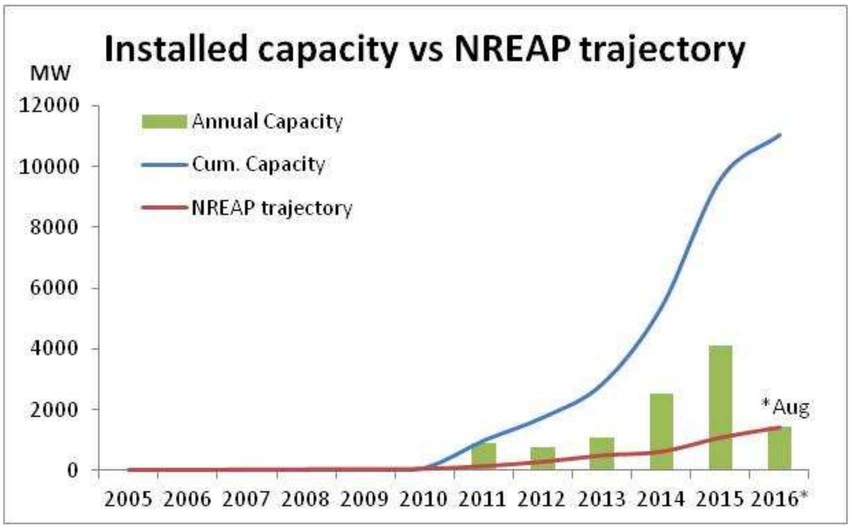

Figure 70: Capacity expansion of PV systems in the UK (Data: EUROSTAT, DECC, UK NREAP[133])

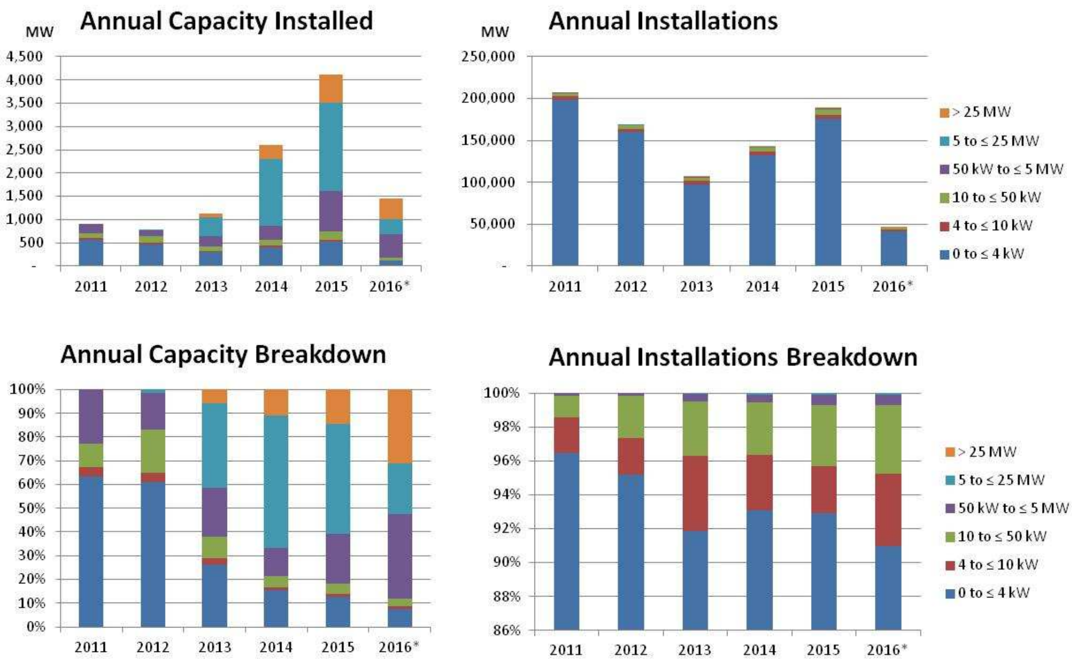

Figure 71: Annual capacity and number of installations breakdown in UK (Data: DECC[134])

Figure 72 shows the breakdown of annual installed capacity and numbers of installations. After the inauguration of the PV strategy in 2013 and the announcement of the termination of FiT for medium and large-scale installations as of 2016, there was a tremendous growth of such systems in terms of capacity. Small-scale installation were predominant, nevertheless their share declined in the last five years.

[133] https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/47871/25-nat-ren-energy-action-plan.pdf
[134] https://www.gov.uk/government/statistics/monthly-small-scale-renewable-deployment

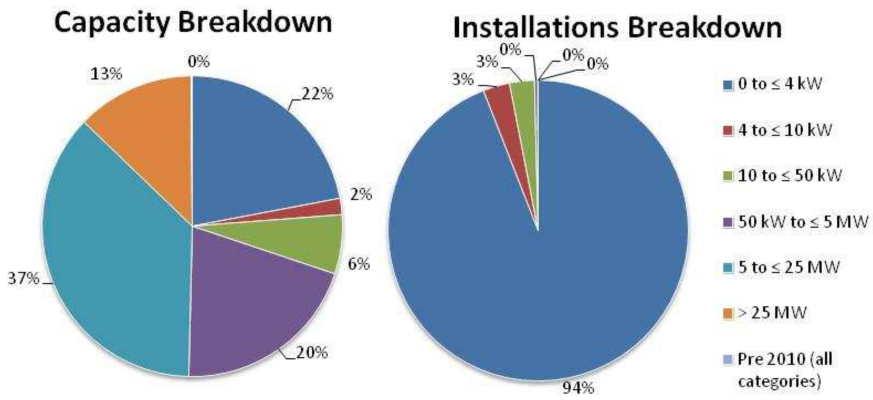

Figure 72: Capacity and installations' number breakdown in the UK as of Aug 2016 (Source: DECC)

4.5.1 Licensing

A generation license is necessary for units exceeding 100 MW and exception is given to units between 50 -100 MW. Evidently, no generation license is required for building-PVs that are generally much smaller than the aforementioned levels. The largest rooftop system in the UK is rated at 6 MW[135].

The installation of PVs on buildings is considered as "permitted development" under the Town and Country Planning Act[136] and no license is generally required, provided that certain provisions apply, i.e.:

- The installed capacity is below 1 MW
- The installation does not exceed more than 0.2 metres beyond the plane of the roof slope
- The installation is not higher than 1 metre above the highest part of a flat roof (excluding chimneys)
- The installation is not installed within 1 metre of the external edge of a flat roof
- If the building is in a protected (i.e. conservation area, Area of Outstanding Natural Beauty, National Park, the Broads or a World Heritage Site) the system is not installed on a roof slope which faces a highway
- The installation is not installed on a site designated as a scheduled monument or on a listed building or on a building near a listed building
- The installation is designed in such a way so as to minimise the effect on the external appearance of the building and the amenity of the area

It is, however, generally recommended[137,138] that planners submit an application to the local authorities in order to ensure that their project complies with the criteria for being characterised as permitted development since local planning ruled may apply.

[135] BRE (2016) Solar PV on commercial buildings: a guide for owners and developers, (K. Arora, S. Diu, J. Roper and G. Hartnell) http://www.solar-trade.org.uk/wp-content/uploads/2016/10/123160_nsc_solar_roofs_good_practice_guide_web.pdf

[136] The Town and Country Planning (General Permitted Development) (England) Order 2015 (SI 2015 No. 596) http://www.legislation.gov.uk/uksi/2015/596/pdfs/ uksi_20150596_en.pdf.

[137] BRE (2016) Solar PV on commercial buildings: a guide for owners and developers, (K. Arora, S. Diu, J. Roper and G. Hartnell)

[138] PV-Finance, project's database http://database.pv-financing.eu/en/database/pvgrid/united-kingdom/national-profile-11/residential-systems/2624/residential-pv-systems-1.html

In case the project does not fall into the previous category then an ordinary planning permission by the local planning authority is required. The application, which may include locally specific provisions, needs to be supplemented by a "design and access statement" explaining the project's response to the site and its setting. For building-PV installations, an Environmental Impact Assessment is normally not required unless requested by the planning authority. The procedure for issuing the planning permission typically takes up to ten weeks.

Notably, a permission by local authorities shall be given for any pruning of trees that is considered necessary (e.g. due to shading) in case of the installation being planned within a conservation area or if a Tree Preservation Order is in force.

As the installation of PVs on building must comply with the Building Regulations compliance can be proven by getting an approval by the local authority or an approved inspector. This is not necessary in case the system is designed and installed by a person/company that is registered to the Competent Person Scheme. A notification of the completion of (electrical) works to the local authorities is also needed.

4.5.2 Grid connection

The grid connection process generally follows the Distributed Generation Grid Connection Guides by the Energy Networks Association[139]. Procedures differ depending on the size and type of the system. Small scale domestic systems up to 3.68kW for single phase connections and 11.04 kW for three phase connections follow the "fit and inform" process, i.e. the DNO is informed by the installed within 28 days after the installation is completed (including connection works). DNOs may ask for correction/adaptation of the carried works and in this case an application is needed, followed by a quotation for the additional costs by the DNO.

For projects up to 50 kW for three phase connections or 17 kW for single-phase connections that include appropriately tested inverters a simplified process is foreseen. After an initial consultation with the DNO during the planning phase, an application is submitted in order to get approval and receive a connection quotation, identifying any necessary costs. Once the quotation is accepted, the installation and connection works may be performed in parallel. Inspection of the commissioned installation by the DNO may be requested.

The procedure is more or less the same for larger systems, however, rules and conditions are stricter hence the application step is more demanding. The necessary works are divided into non-contestable works, i.e. those conducted by the DNO and contestable ones that may be carried out by independent companies called independent connection providers. In many cases, local network conditions lead to the necessity of reinforcement works that increase the costs significantly.

Since April 2015 a provision allows two FiT projects to share a common grid connection if at least one is a community owned system.[140]

4.5.3 Support mechanisms

[139] http://www.energynetworks.org/electricity/engineering/distributed-generation/dg-connection-guides.html

[140] http://www.energynetworks.org/assets/files/DGCG%20G83%20Multiple%20Summary%20April%202016%20CESv1.pdf

There are three major support schemes currently in place in the UK. Renewable Obligation (RO) is the oldest one, initially introduced in 2002 and planned to last until the 31st of March 2017. It is based on an obligation imposed to suppliers to procure a specific share of the electricity sold from RES. Each MWh of RES-e receives a number of Renewable Obligation Certificates from Ofgem (1,3 ROCs/MWh for PVs currently). ROCs are traded on the market thus creating an additional value for the producer apart from the price of electricity.

On April 2010 a FiT scheme was introduced in order to promote the deployment of small and medium size RES units up to 5MW. The scheme provides a fixed generation tariff for the electricity produced and a retail price indexed export tariff for surplus electricity exported to the local grid. Additional savings could be achieved from onsite self-generation. The self-generation level is fixed at 50%for small scale systems up to 30 kW, while larger systems need to have appropriate metering equipment. Systems that have received grants are not eligible for FiT.

In order to be able to benefit from the FiT scheme, owners of small scale PV systems up to 30 kW need to ensure that the systems is installed by an installer certified by the Microgeneration Certification Scheme (MCS) and that MCS certified equipment is used. For larger systems a so called ROO-FIT accreditation by Ofgem shall be granted. A preliminary accreditation is foreseen, in order to assure the prospective producer of the level of the tariff and facilitate financing of the project. The preliminary accreditation has a certain validity period (6 months for PV systems and 12 months for community owned PV systems) within which the project needs to be commissioned. A tariff guarantee period of one year exists for community and school applications bellow 50 kW through a pre-registration process.

For building-PV systems the generation tariff depends also on the energy efficiency rating of the building, with the higher tariff being attributed to the more efficient ones (Energy Performance Certificate (EPC) rating of level D or above). Since December 2012 a relaxation of the energy efficiency requirement to community owned systems and schools has been provided[141]. For generators that own or receive FiT payments from more than 25 installations up to a total capacity of 250 kW special provisions apply that reduce the applicable generation tariff.

The tariffs' level is reviewed annually by Ofgem. The latest generation tariff rates are presented in Table 14 while the export tariff for the period April 2016 to March 2019 is set at 4,91 p£/kWh.

The FIT scheme was paused from 15 January 2016 to 7 February 2016 and was reinitiated incorporating a quarterly degression depending on the level of deployment of the technology that reduces the generation tariff as annual interim capacity caps are reached. Due to persisting cost considerations there are plans to terminate the provision of the generation tariff for new installations from 2019 onwards, leaving only the export tariff as additional support to the savings from self-consumption.

$p£_{2016}$/kWh		Apr Jun 2016	Jul Sep 2016	Oct Dec 2016	Jan Mar 2017	Apr Jun 2017	Jul Sep 2017	Oct Dec 2017	Jan Mar 2018	Apr Jun 2018	Jul Sep 2018	Oct Dec 2018	Jan Mar 2019
P< 10 kW	**H**	4,32	4,25	4,18	4,11	4,04	3,97	3,90	3,83	3,76	3,69	3,62	3,55
	M	3,89	3,83	3,76	3,70	3,64	3,57	3,51	3,45	3,38	3,32	3,26	3,20
	L	0,74	0,61	0,57	0,52	0,47	0,42	0,37	0,33	0,29	0,23	0,19	0,14
10 kW< P < 50kW	**H**	4,53	4,46	4,39	4,32	4,25	4,19	4,12	4,05	3,98	3,91	3,85	3,78
	M	4,08	4,01	3,95	3,89	3,83	3,77	3,71	3,65	3,58	3,52	3,47	3,40
	L	0,74	0,61	0,57	0,52	0,47	0,42	0,37	0,33	0,29	0,23	0,19	0,14

[141] https://www.ofgem.gov.uk/system/files/docs/2016/04/fit_community_and_schools_guidance_v3.pdf

50 kW< P < 250kW	**H**	2,38	2,09	2,03	1,99	1,94	1,89	1,84	1,78	1,74	1,68	1,64	1,58
	M	2,14	1,88	1,83	1,79	1,75	1,70	1,66	1,60	1,57	1,51	1,48	1,42
	L	0,74	0,61	0,57	0,52	0,47	0,42	0,37	0,33	0,29	0,23	0,19	0,14
250 kW< P < 1MW		1,99	1,75	1,69	1,65	1,59	1,55	1,50	1,44	1,40	1,34	1,30	1,25
P > 1MW		0,74	0,61	0,57	0,52	0,47	0,42	0,37	0,33	0,29	0,23	0,19	0,14
Stand-alone solar photovoltaic		0,74	0,61	0,51	0,47	0,42	0,38	0,33	0,30	0,26	0,21	0,17	0,13

Table 14: Latest FiT levels for PV installations in the UK (Data: Ofgem[142])

Since 2014 large scale PV systems over 5MW either ground mounted or on buildings may receive support only through a Contract for Difference (CFD), which is similar to a Feed in Premium scheme. A producer that is under a CfD with the government-owned Low Carbon Contracts Company (LCCC) receives the difference between a predefined strike price and the reference market price. The strike price is defined though an auction. In the first auction that took place in February 2015 five PV projects with cumulative capacity of 72 MW were successful and the average strike price was 67.53 £/MWh[143].

The following Figure 73 shows the breakdown of PVs into the different support schemed in terms of capacity and in terms of the number of installations.

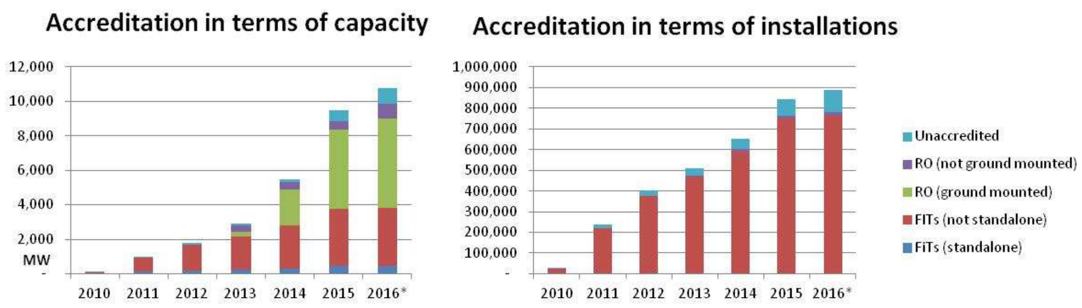

Figure 73 Breakdown of accreditation of PV installations in the UK (Data: DECC[144])

Finally, an exemption from the Climate Change Levy was provided to renewable energy generators that did not opt for a FiT until August 2015. This was done through the issuing of Levy Exemption Certificates by Ofgem for the electricity generated.

4.5.4 Project financing

After the introduction of the FiT there are no grants available specifically for PV systems in the UK. Until recently the Green Deal energy saving programme was a way to get support for building attached PV systems as part of an energy efficiency renovation, however the programme has been terminated.[145]

Ordinary financing ways e.g. through banks are the usual practice and loan conditions depend on the credit worthiness of the applicant as well as the system's technical and economical

[142] https://www.ofgem.gov.uk/publications-and-updates/feed-tariff-fit-generation-export-payment-rate-table-01-october-31-december-2016

[143] https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/407059/Contracts_for_Difference_-_Auction_Results_-_Official_Statistics.pdf

[144] https://www.gov.uk/government/statistics/monthly-small-scale-renewable-deployment

[145] https://www.gov.uk/green-deal-energy-saving-measures

characteristics. The revenue streams, e.g. through a FiT, a supply contract or simply through savings of the electricity bill, is also important.

Third party financing e.g. through leasing is also another way of installing a PV system. Some variations exist, e.g. an Energy Services Company (ESCO) may install the system on a school and be compensated through monthly instalments equal to the cost reductions due to own consumption[146].

For community organisations and schools funding through RES-coops, community or crowd funding and donations may also be possible. Community solar projects are also eligible for inclusion in ISAs (Individual Savings Account),[147] which provides a tax-free savings allowance for individuals investing in peer-to-peer finance. There is also evidence of debt-financing through bond offers, for community solar projects[148].

4.5.5 Ownership and business models

Since the issue of the solar PV strategy in 2013, a lot of emphasis has been given to community owned schemes. The strategy announced an initiative to install 1GW of PV systems on governmental buildings and schools. For this reason, a number of measures to facilitate the installation of PV systems for community organisations and schools have been taken. These included easier administrative procedures and longer PV guarantee periods for FiT but no direct financial incentives. However, out of the 1580 preliminary accreditations granted until Aug 2016, only 177 cases have received full accreditation.

The operation of solar PV systems through PPAs seems to be mature in the UK especially for large commercial projects[149]. Via the PV-Financing project a number of variations of PPA models have been identified and their characteristics are presented in the following table[150]. The PPA may be signed between the producer and a supplier of electricity or between the installer and the owner/user of the building (similar to a leasing contract).

BUSINESS MODEL	REVENUES	CAPEX	OPEX	COST OF CAPITAL	SCALE	PROFITABILITY
Wholesale PPA	Low: Wholesale market price	Historically high due to policy-led "rushes"	Can be high due to access issues with landowner	Dependant on wholesale electricity projections and how volatile or accurate these are	Plenty of scale possible as all that is need is land, grid and an off-taker	Was profitable with ROCs and high price forecasts, now not profitable
Sleeved PPA	Medium: competing with retail prices, but including grid costs	Same as above, although transactional costs high due to complicated legal structure	Same as above	Dependant on credit-worthiness of corporate consumer, which has proven challenging	Similar to above, but transactional costs quite high, so not suited to smaller projects	Was profitable with ROCs, now may not be profitable
Onsite direct wire (Private wire)	High: competing with commercial retail prices, avoiding grid costs	Potential reductions through e.g. grid efficiencies, but potential challenges from geographical constraints	Same as above, although rental costs and access may differ on consumer-owned sites	Dependant on credit-worthiness of corporate consumer, which has proven challenging. Additional challenges from "stranded asset" risk	Limited market size, as challenging set of requirements	In theory profitable, but challenges remain making projects viable

Table 15: PPA models and their characteristics (Source: BRE[88])

[146] https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/301472/Power_to_the_Pupils_leaflet_-_7_April_2014.pdf
[147] https://www.ofgem.gov.uk/system/files/docs/2016/04/fit_community_and_schools_guidance_v3.pdf
[148] http://www.pv-magazine.com/news/details/beitrag/uk-improves-attractiveness-of-community-solar-investment_100018039/#axzz4Pp3WVyqp
[149] BRE (2016) Solar PV on commercial buildings: a guide for owners and developers, (K. Arora, S. Diu, J. Roper and G. Hartnell)
[150] http://www.solar-trade.org.uk/wp-content/uploads/2016/11/Making-Solar-Pay-The-Future-of-the-UK-Solar-PPA-Market.pdf

4.6 Conclusions on the framework conditions of selected MSs

All five of the selected MS show a rather impressive deployment of the PV technology that exceeds their national targets as defined in their NREAPs. This fact proves the rather unexpected development of the technology leading to a steep cost reduction curve, but may also provide evidence of overwhelming support that overheated the market. With the exception of the Netherlands all other selected MS have experienced an abrupt decline in investments as a consequence of reductions in support levels. The Netherland on the other hand followed a more conservative approach towards supporting PV installations that still seems to provide steady growth possibilities.

In all cases the capacity expansion was backed up with a more or less clear licensing framework, often with fast track, one-stop-shop procedures. For small scale installations this seems to play an important role for the investment decision. Similarly grid connection rules and conditions are clearly set increasing transparency and developing more confidence to investors. Most DSOs have responded effectively in their new role and have acted as facilitators especially for small scale systems, developing the necessary technical specifications and administrative procedures.

The financing conditions vary between the different MS largely depicting the general economic conditions. In MS with a competitive economy like Germany, the Netherlands and the UK favourable credit lines for this low risk investment are still open, while on the other hand in Italy and most evidently in Greece financing is rather difficult.

The maturity of the technology and the market of PVs lead to the development of new business models especially in the northern MS. Cooperatives and community owned systems as well as long term PPA schemes have emerged enabling the continuation of the development of small scale PV systems.

	Germany	Greece	Italy	Netherlands	UK
2020 PV targets (MW)	51,753	2,200	8,000	722	2,680
PV capacity in 2015 (MW)	39,762	2,606	18,924	1,405	9,581
PV capacity per capita in 2015 (MW/inhab.)	490	242	311	83	138
Main support scheme for small scale rooftop-PVs	FiT	FiT, NM*	NM	NM	FiT

***NM: Net metering**

Table 16 Overview of PV deployment and support indicators for the selected MS.

5 Review of pilot programmes

As already mentioned in the previous chapter the deployment of roof-top PVs, especially in the early stages, became possible through the implementation of PV specific pilot programmes that provided an enabling framework through adequate financing and support. National-wide programmes proved quite successful in achieving a fast development of the first critical mass of projects and contributing to the maturity of the technology and the market through the learning by doing process. National programmes paved the way to regional or local initiatives that further facilitated the continuation of the deployment of customised PV installations according to local needs and targets. This section presents some characteristic examples of both national and local programmes providing an overview of the main features that will facilitate the design of appropriate programmes in the EPCs.

5.1 National programmes

5.1.1 Germany – the 100.000 roofs programme

The 100.000 roofs programme in Germany was initiated in 1999 and run up to 2003 as a major follow up of various support schemes during the previous years. The programme was initially designed as a zero interest credit line by KfW, covering the total cost of the investment and targeting individuals and SMEs. The results of the first year did not fulfil the expectations; out of a total of 3,922 applications, 3,522 were approved and nearly 9 MW of PV systems were installed. However, the introduction of a FiT for PV systems on April 2000, as high as 500 €/MWh for rooftop installations and guaranteed for 20 years together with the possibility to run in parallel with the KfW soft loan programmes, created a very favourable investment environment, which reinforced the interest for new installations. As a result the number of applications rose by more than four times to 17,090 in 2000 and continued at these levels peaking up at the last year of implementation to 21,423 applications.

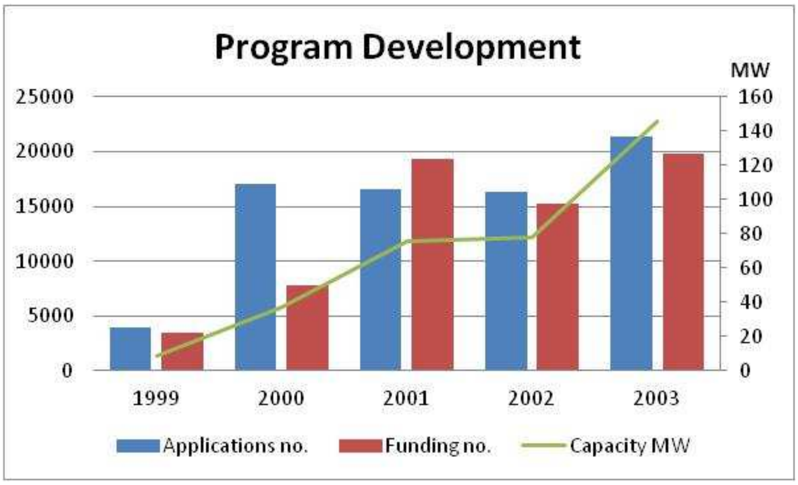

Figure 74: Development of applications and installed capacity for the 100.000 roof programme (Data: KfW[151])

Altogether the programme was considered successful as it resulted in the installation of 65,702 PV systems totalling some 346 MW of capacity. Total funding provided amounted to 1.7 billion € while total realised investments reached 2.4 billion €. The average installed capacity of systems rose from 2.5 kW in 1999 to 7.5 kW in 2003 with systems up to 100kW being installed on roofs[152]. This trend indicates the attractiveness of the programme in combination with the FiT scheme also for commercial applications. However, the biggest share, 79%, of installations was attributed to systems below 6 kW with only 18% of the systems being above 20kW. The following chart (Figure 75) provides a breakdown of the systems in categories depending on the positioning characteristics. Evidently, the vast majority of the systems (93%) were installed on roofs.

[151] KfW, Perspektiven Erneuerbarer Energien: Das 100.000 Dächer-Solarstrom-Programm: Eine Schlussbilanz, in Mittelstands- und Strukturpolitik, Ausgabe 31, November 2004. https://www.kfw.de/Download-Center/Konzernthemen/Research/PDF-Dokumente-KfW-Beitr%C3%A4ge-zur-Mittelstands-und-Strukturpolitik/KfW_VW-Beitrag_Nr_031.pdfhttps://www.kfw.de/Download-Center/Konzernthemen/Research/PDF-Dokumente-KfW-Beitr%C3%A4ge-zur-Mittelstands-und-Strukturpolitik/KfW_VW-Beitrag_Nr_031.pdfhttps://www.kfw.de/Download-Center/Konzernthemen/Research/PDF-Dokumente-KfW-Beitr%C3%A4ge-zur-Mittelstands-und-Strukturpolitik/KfW_VW-Beitrag_Nr_031.pdf

[152] Teske S. and Hoffman U., A history of support for solar photovoltaics in Germany, in Mallon K., Renewable Energy Policy and Politics a handbook for decision making, Earthscan, London, Sterling VA, 2006

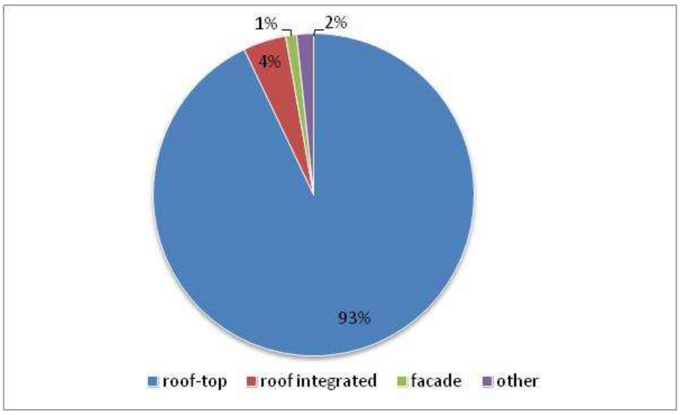

Figure 75: Breakdown of systems according to positioning characteristics (Data: KfW)

It is also worth mentioning that nearly 84% of the funding approvals referred to individuals, while 73% of the systems in terms of capacity were installed in the two southern States, namely Bayern and Baden-Wurttemberg.

Apart from the significant deployment of PVs during its duration the programme achieved significant collateral targets. The programme was partially driven by the country's industrial policy regarding the PV technology, which at the time was too expensive to be commercially deployed without significant support. Hence, by creating a significant internal market for PVs the programme triggered significant innovations and technological developments, which enabled the reduction of the cost of PVs. The later massive global uptake of the technology enabled the harvest of significant added value for the German industry. However, it is recognised that the achievements became possible only after the combination of the program's funding possibilities with the support provided by the FiT scheme[153].

5.1.2 Italy roof top PV initiatives

The Italian rooftop PV promotion initiatives have seen three different momentums:

- the 10,000 roof top programmes, a capital incentive lasted between 2001-2006;
- the five Conto Energia programmes including significant tariff premium for rooftop installations;
- the current 50/65% tax rebate mechanisms for households.

In addition, a number of facilitations has been introduced in order to enhance rooftop installations.

5.1.2.1 10,000 rooftop programme:

In early 2000 a specific initiative, promoted by the Ministry of Environment, was launched in order to incentivise small size PV grid connected installations up to 50kW. The so-called 10,000 rooftop programme was initiated in order to support installations in public buildings and private households. The programme was based on a capital incentive covering up to 75% of final costs of the PV system. The selection procedures took place at regional level and a merit order, based on lowest capital contribution request, was formulated in order to select the eligible requests. The programme was financed by the Ministry of Environment with limited resources (30 m.€ coming from the 1999 carbon tax on electricity production) and did not bring any significant result in terms of capacity. Focused on small size systems, the programme gave evidence of the complexity of regulation and administrative procedures connected with small-scale solar system.

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At the time, regional and municipal administration was not ready to implement PV incentive mechanisms at local level, while special planning and permit procedures did not exist in decentralised administration offices especially for small-scale RES systems. Moreover, banks were not ready to release loans for PV installations, estate managers had no experiences and there were no rules or guidelines in place regarding the installation of a PV system on apartment buildings' roofs belonging to more than one owner. In addition, DSOs had no experiences with such systems and there were no rules for third party network connection.

The programmes, however, served as an introductory experience to overview the small size PV sector and identified the relevant areas to work on, in order to design a successful national strategy. Thanks to the 10,000 PV programme the Electricity Authority moved on with introducing the net metering regulation.

5.1.2.2 Conto energia and the rooftop programme

Under this scheme the main incentive to rooftop PV system comes from the feed-in prices which were differentiated according to the size of the system. An example is given in the following table from the 3rd Conto Energia. All phases of the Conto Energia are designed under the same principles.

An intermediate incentive between the two values was introduced for PV mounted on structures not considered as roofs, such as greenhouse, verandas, etc. In addition, a premium was provided to PV technologies integrated in the structure of the building (roof or walls).

Installed capacity	Roof mounted	Ground mounted
1<3kW	0,402	0,362
3<20kW	0,377	0,339
20<200kW	0,358	0,321
200<1000kW	0,355	0,314
1000<5000kw	0,351	0,313
>5000kW	0,333	0,297

Table 17 Feed-in premium in €/kWh of 3rd Conto energia per size of plant and installation structure

Installed capacity	Premium tariff c€/kWh
1<20kW	44
20 <200kW	40
200<5000kW	37

Table 18: Feed-in premium for BIPV systems in Italy

Finally, a specific premium of an additional 10% was added if the PV rooftop installation was done in conjunction with the substitution of asbestos roofs while a 5% premium was available to installations of roof-top PV systems on public administration buildings in municipalities with less than 5,000 residents.

5.1.2.3 Tax rebate

The scheme refers to renovation works of private buildings and consists of a rebate of up to 50% of the amount spent over a period of 10 years through taxation. In case the restoration work results in the building reaching a specific high energy efficiency standard, the rebate can be extended up to 65% of total cost. Costs related to PV systems including installation and labour costs are eligible for a tax rebate.

The rebate consists of reduced tax payments for a period of 10 years. Each year taxes are reduced by 1/10 of the overall qualified (50% or 65%) PV installation cost. This is to say if the total installation cost is 10,000€, each year taxes are reduced by 500 € over a period of 10 years, 650€ in case of energy efficiency higher standards.

The scheme is included in the financial law and has to be confirmed by the national budget. For 2016 the maximum support provided under the scheme for all restoration works is set to 96,000 € and discussions for 2017 are currently ongoing. If not approved, the maximum applicable cost of restoration works for tax rebate will be reduced to 48,000 €.

The rebate is only accessible to individuals and companies are excluded. The procedure for the ordinary 50% rebate is simple; all payments have to be done through a specific form available in the associated banks. For the 65% rebate a more complex procedure is foreseen, involving certification of energy efficiency standards by the National Energy Agency (ENEA). Notably, the fiscal incentive may be transferred to a third party that may be the company installing the PV system.

The fiscal rebate has to be calculated together with the ratio of self-consumption in the household and the net metering quota to be exchanged with the grid. The fiscal rebate has the effect of reducing the size of the system in order to maximise the self-consumption quota, which is the most profitable for the final users. Self- consumed electricity has, in fact, a value of some 23c€/kWh whereas net metering is around 10c€/kWh.

In 2015, 94% of the overall installed PV capacity in the country was supported by FiT, compared to 97% in 2013. Evidently, the tax rebate system in the domestic sector is the main driver for new installations. However, the market has considerably slowed down.

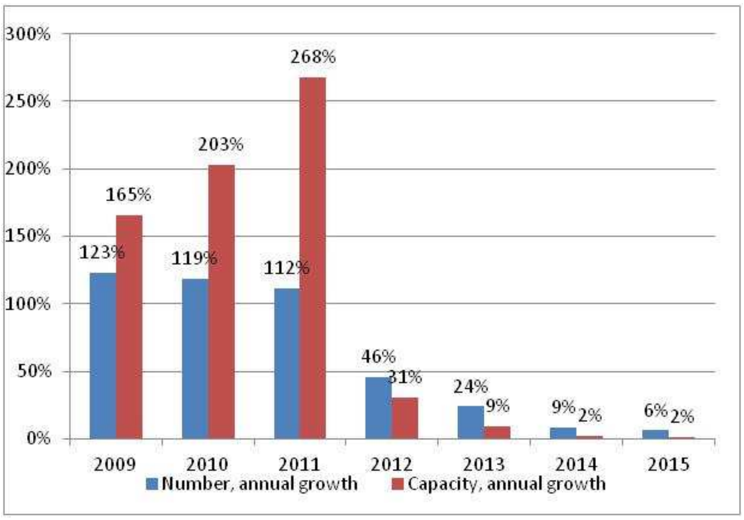

Figure 76: Annual growth of PV installations in Italy (Data: GSE)

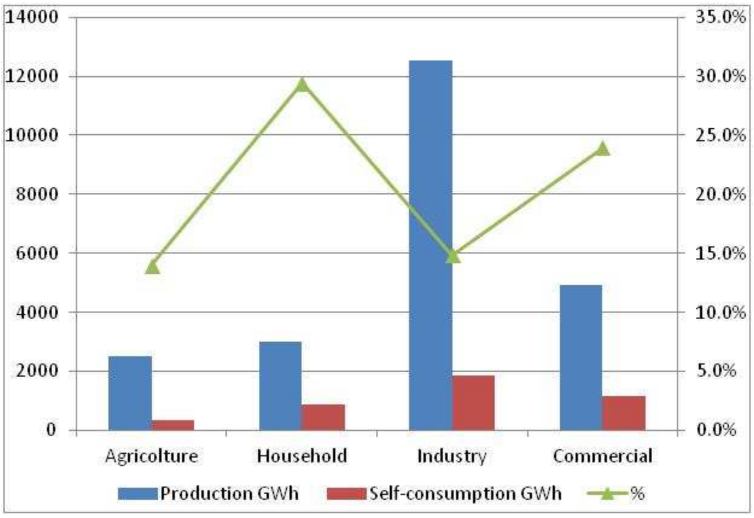

Figure 77: Production and self-consumption per final user category in Italy in 2015 (Data: GSE)

The household sector shows the highest percentage of self-consumption, 28%, over total annual production, commercial sector reaches 24%, industrial and agriculture sector shows a 14% of self-consumption. The average installation size in 2014-2015 has dropped well below 10kW, reaching 8.1kW and 7.1kW respectively, thus confirming the market prevalence of small scale household PV installations. A total number of 40,202 systems were installed in 2015, showing a 22% reduction from the 52,000 installation in 2014. Total installed capacity in 2015 was 298 MW as compared to 424 MW in 2014 (-30%).

The average size of the PV systems installed is reduced for all final user categories as a result of increasing self-consumption. Table 19 below, shows the average size of installed systems per sector (agriculture, household, industry, commercial) over cumulated capacity and the average size of installed systems in 2015. The significant deviation in 2015 from the national average is explained by the change of incentive support. Whereas in the past the FiT was favouring larger installation with smaller share of self-consumption, net metering and tax rebate result in systems of smaller size in all end users category in order to increase the share of self-consumption. During the feed-in mechanism, larger systems were installed in order to benefit from the incentive scheme.

	Average size (kW) of installed PV systems in 2015	
	over cumulative capacity in 2015	over installed capacity in 2015
Agriculture	114,8	23,8
Household	4,9	4,1
Industry	232,7	73,1
Commercial	51,4	23,2
Total	27,4	7,4

Table 19: Average size of system per end user category, total capacity and 2015 installation (Data: GSE)

5.1.2.4 Other mechanism to facilitate rooftop PV

In addition to the aforementioned mechanisms, important secondary regulation has been introduced to promote PVs in buildings like net-metering and fiscal measures that have already been discussed. Facilitated licensing and authorisation procedures, specific rules to approve roof mounted PV in multi-apartment buildings have already been described.

Moreover, an obligation to include renewable energy sources in new buildings was introduced in 2012. The obligation regards at least 50% of the new buildings' hot water demand to be provided by RES and a minimum of RES capacity per surface of the new building. More specifically, the obligation for 2013 was at least 1kW of electrical renewable capacity for each 80m^2 of building surface. The obligation has been adjusted since then, reducing the surface per kW to 65m^2 for the period 2014-2016 and to 50m^2 from 2017. For public buildings, the capacity obligation is increased by 10%. A premium on concession of building volumes up to 5% is provided to innovative buildings exceeding the obligation's minimum requirements by at least 30%. Although the present obligation scheme applies to all national territory, Regions are allowed to increase the minimum standards.

At regional and municipal scale special incentives for the integration of solar technologies in buildings are sometimes introduced within the authorisation procedures for restoration of buildings and for requests to increase of building's volume. For instance, a 15% increase in a building's volume can be granted if PV systems are installed and energy efficiency specific standards are met.

5.1.3 Special rooftop PV programme in Greece

The special programme for rooftop PVs in Greece was initiated in July 2009 in the mainland (Interconnected System, IS) and in January 2011 on the Non-Interconnected Islands (NII) and according to its initial planning will last until end of 2019. The programme foresees the payment of a FiT through net billing. The FiT is guaranteed for 25 years for the electricity produced and fed into the grid from PV systems up to 10kW for the IS and Crete island and up to 5kWp for the rest of the NII. The systems may be installed on the roofs, facades as well as on auxiliary spaces, such as warehouses. In any case, the rules and conditions of the New Building Code (2012) are applied.

Eligible to participate in the programme are individuals, SMEs, public bodies and non-profit organisations. The applicant shall be the owner of the building or the roof (e.g. in case of apartment buildings). In order for the net billing to be possible, an operating connection on the name of the system's owner shall exist at the building. In case of commonly owned/used space a single PV system may be installed provided that there is an agreement by all the owners.

An additional prerequisite in case of residential buildings is the use of solar thermal installations for the supply of at least part of the needs of the building for thermal water. Systems that benefit from other support schemes such as investment grants cannot benefit from this program.

The level of the FiT was initially set at 550€/MWh and was kept like this until 2012. This resulted in a very high remuneration for the conditions of Greece (average rooftop system annual production 1,400 kWh/kW) even at the relatively high cost of the PV systems at that time. Consequently, there was strong interest for installing such systems that was backed by the almost unconditional provision of loans from banks at a relatively high interest rate. However, the increase of the cost of the programme and the decrease in the cost of PV systems resulted in the reduction of the FiT from 2012 onwards through continuous ministerial decrees. On April 2014 a retroactive reduction took place, while from May 2013 onwards the tariffs were set at levels that are prohibitive for any such installation. The development of the installed capacity during the whole period of the programme is depicted in Figure 78 while Figure 79 shows the subsequent readjustment of the FiT.

The programme is currently on a de-facto hold due to the low tariffs, the loss of confidence from the continuous changes in the framework and the emerging of net metering that provides more benefits.

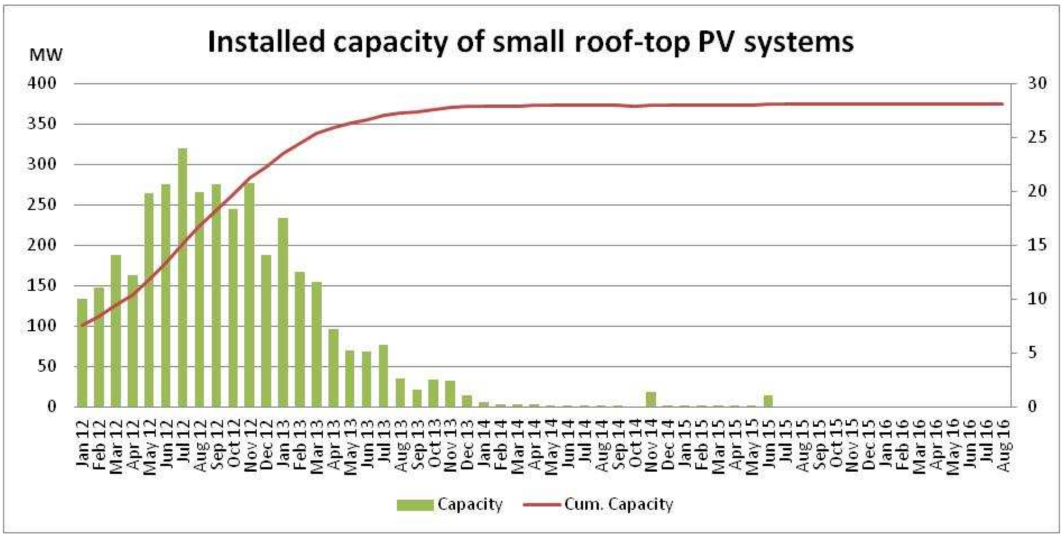

Figure 78: Evolution of the installed capacity of small roof-top PVs in Greece. (Data: HDSO[154], HMO[155])

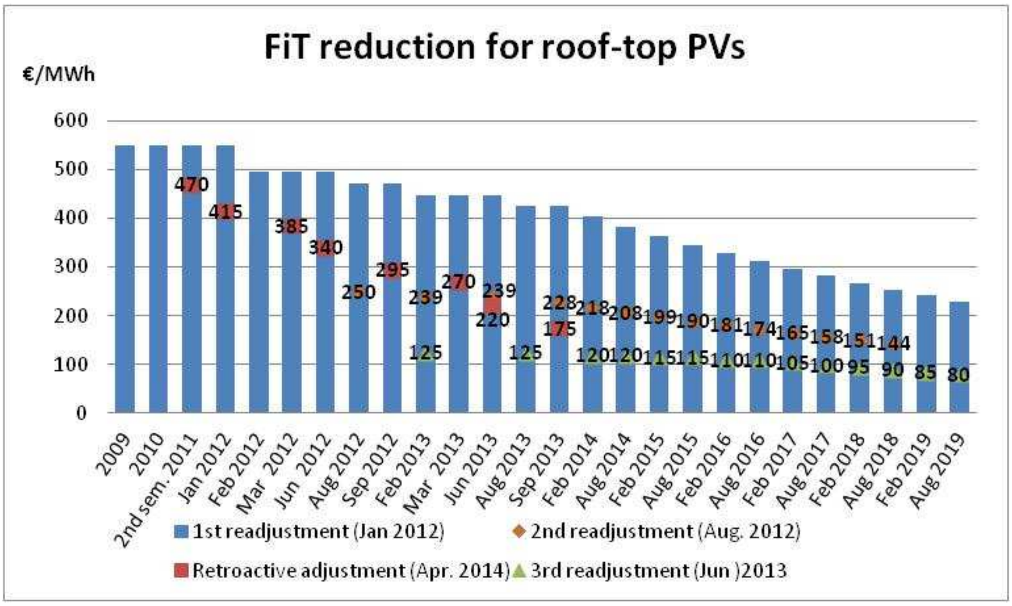

Figure 79: FiT reduction for PV systems of the Special Rooftop PV Programme in Greece (Data from national legislation)

5.2 Local programmes

While the rapid uptake of PVs was mainly supported through national support programs, there is currently an increasing role undertaken by municipalities and regional authorities. This role is enforced by the fact that the climate change and energy policy at European level is transferred from the central planning to regional and local level. The success of the European Covenant of Mayors and the merge with the similar global Compact of Mayors, following the Paris Climate Agreement is a clear sign of this global trend.

[154]http://www.deddie.gr/el/upiresies/fwtovoltaika-kai-alles-ape/fv-tou-eidikou-programmatos-stegwn

[155]http://www.lagie.gr/systima-eggyimenon-timon/ape-sithya/miniaia-deltia-eidikoy-logariasmoy-ape-sithya/

Based on a long tradition, a wide range of specialised local programmes for supporting the deployment of renewable energy are in place in the MS. These usually refer to the provision of grants or soft loans for citizens and local SMEs or the development of PV projects on public buildings as a part of a general energy strategy. A brief description of three characteristic programmes is given hereafter.

5.2.1 Bristol community energy fund

The Bristol City Council (BCC) is highly active in the field of energy and climate change policy and has already set a promising target to reduce carbon emissions from its buildings & operations by 40% by 2020 from 2005 levels[156]. The Energy Service department of the BCC, established as early as 1992 as an Energy Management Unit, is working towards these target through various project. Among other achievements, the Energy Service has been involved in the installation of PV on 46 schools and 32 domestic sites. At the same time, it is working on the design of a four-year framework towards the mobilisation of some £47m for investments in PV projects on public buildings and public space.

Currently the BCC is running the Community Energy Fund, established in 2015, that provides funding up to £10,000 to community energy groups, in the form of soft loans for RES projects (as of 2016) and grants for other energy related investments. Apart from facilitating investments, the fund is targeting in creating a "community energy movement" through the adoption of an inclusive approach towards achieving the City Council's sustainability targets. The fund gives priority to equalities-led groups or organisations, communities affected by energy issues such as fuel poverty, or groups who are underrepresented in the energy movement. More information about the Community Energy Fund can be found at: http://www.bristolcommunityenergy.co.uk/news/.

5.2.2 Stuttgard "intracting" programme (internal contracting scheme)

The City of Stuttgart has a long record of energy related activities that goes back to the energy crisis of the '70s. In its efforts to address energy saving issues under budgetary constraint, the Energy Management Department introduced the 'internal contracting (*intracting*)' model together with the City Treasury.

The model is based on the idea of the services provided by ESCOs, i.e. financing of projects through energy savings, but works completely within the city councils internal structures. Investments are financed by the Environment Department from a special budget item, to which the energy cost savings are later returned. The following figure graphically describes the "intracting" scheme. Although the scheme was mainly designed for energy efficiency and energy management projects, it may well be applied for small scale RES projects on public buildings. More on the intracting model may be found here: http://www.energy-cities.eu/db/stuttgart_136_en.pdf.

156 https://www.bristol.gov.uk/policies-plans-strategies/the-energy-service

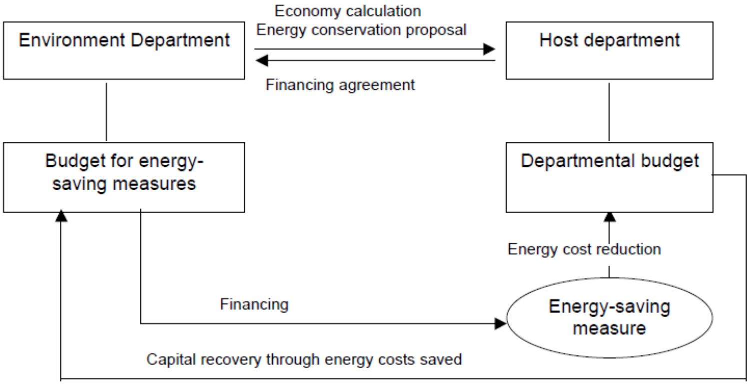

Figure 80: Graphic explanation of the intracting model (Source: Energy Cities[157])

5.2.3 Solar exchange – Lausanne

This programme started in 2000 in the City of Lausanne and is based on the willingness of electricity consumers to pay more for green electricity. The programmes, led by the local utility company (Lausanne's Utility Company), brought together these consumers with companies developing PV systems on private buildings. The later finance and complete the projects and sell the produced energy to the utility company that charges green electricity consumers accordingly. According to available data almost 4% of all electricity customers of Lausanne Utilities, had subscribed to the scheme until 2008.

[157] http://www.energy-cities.eu/

6 Conclusions and Recommendations

A wide range of policies and instruments have been used in the EU for the promotion of RES in general and building attached PVs specifically. In the initial phase of the commercialisation of the PV technology, specialised support programmes were common. As the technology reached a certain level of maturity, policy support mainly provided through the national schemes for RES. In many cases, complementary policy targets were used to further facilitate investments e.g. energy efficiency targets, building retrofitting or asbestos roof replacement. Assistive tools, such as tax regulations, overall investment enabling frameworks are also used.

National schemes are often coupled with regional and local initiatives either in the form of additional support, e.g. through grants, or in the form of a more enabling framework, e.g. simple administrative procedures or beneficial planning rules. As the focus of the EU climate change policy is moving from nationwide to regional and local scale, these kinds of initiatives, often supported by the mobilisation of cohesion funds, might increase.

Notably for PVs, MS set different targets regarding the characteristics of the systems to be promoted. Some MS focused on medium and large-scale investments thus succeeding in a fast deployment of the technology in terms of capacity, while others favoured small scale building attached systems. In this case, penetration in terms of capacity was evidently lower, however the uptake of the technology was based on a large number of distributed systems making it somehow a social acquis, since it involved more than the mobilisation of adequate funds. Building attached PVs show a persistent growth in comparison with large scale investments, which have been stalled in many cases after the reductions in the level of the support since companies active in utility scale projects opt for more favourable markets outside the EU.

Another interesting outcome is that the comparatively wide commercialisation of the technology has significantly reduced, and in certain cases eliminated, the need for economic support especially for small scale self-production systems. In some MS, especially in the “more productive” from a solar PV perspective Southern Europe such as Spain, Italy and Greece, the level of retail electricity tariffs is enough to encourage self-production of electricity through a proper enabling framework. Consequently, innovative tools and instruments such as leasing contracts, PPAs etc. have emerged in order to create sensible business models without the need of FiTs.

Evidently, the sector in the EU moves from a risk free, high rate of return on investment to a mature, low to medium risk business case that needs careful design and planning. This desirable transformation is, however, the outcome of many pitfalls and lessons learned in designing and especially monitoring the support mechanisms. These inefficiencies increased unreasonably the cost of the support beyond necessary levels. In MS with inadequate monitoring mechanisms and slower reactions such as Spain and Greece, retroactive contractual changes took place, creating regulatory instability that hurt the confidence of investors[158]. In such cases, the reactivation of the sector becomes more difficult even if the conditions remain economically favourable since the risk of repeating such radical measures is a preventive factor.

The early EU experience has also revealed that economic feasibility is a significant part of the decision process but not the only one. The overall framework is equally important in the domestic sector and for SMEs whose activity is not energy related. A clear, streamlined procedure for the implementation of such a project is necessary in order to increase confidence and reduce non-economic considerations. Adequate information on the technology and the economics of the investment, the concept of the one stop shop and the possibility for online electronic submission of applications are important facilitating factors.

[158] See Box 3 for a short description of the RES account deficit problem in Greece

Planning rules should be clearly defined and where possible in a common manner nationwide. A careful planning framework that takes into account building conditions and codes, has an appropriate level of detail and reduces exemptions to the minimum without neglecting environmental, cultural and architectural considerations has a decisive role in facilitating building attached PVs.

The involvement of the DSOs in the process is of outmost importance for small scale distributed generation systems like building attached PVs. Evidently, for such systems the DSOs act as the facilitator of the whole process in some MS. For example in Greece the DSO acts as one stop shop for most small scale roof-top installations bellow 100kW. The role of the DSO is also important in enabling the maximum uptake of distributed PV generation by ensuring at the same time networks safety and reliability. On the other hand, the EU framework on the electricity market and RES has set clear rules on the responsibilities of DSOs reducing the introduction of unjustifiable barriers regarding the connection of third parties to the grid, a prerequisite for distributed generation.

A certification process for installers and equipment has also been proven to be an important factor for enabling the implementation of projects as it increases the investors' confidence in the technology and eliminates possible risks. In certain cases, certification has enabled the further simplification of the process as the involvement of a certified installer is considered administratively adequate in order to reduce the need for certain permits. Such certification mechanisms however are reasonable and successful only in the case of a market of significant size as they imply some additional costs.

The aforementioned outcomes and lessons from the EU experience shall be taken into consideration for the design of meaningful and successful programmes for building attached PVs in the Eastern Partner Counties. It shall be noted, however, that the success, to a large extend, of the PV deployment in the MS is largely based on a strong EU policy towards a liberalised design and integration of electricity markets coupled with the EU RES policy and the relevant commitments of the individual MS.

BOX 5: Recommendations for the design of building-PV policies in the Eastern Partner Countries

Preliminary work

- Identify the current overall energy framework and the special policy framework on RES. Examine the evolution of electricity prices and tariffs, the existence of subsidies and issues like non-payment rates, electricity theft and energy poverty. Consider the use of electricity in each sector, the load profiles and the overall distribution network conditions.
- Examine the overall economic conditions especially regarding the income level of households and SMEs and the energy/electricity related expenditure share.
- Examine the technical and economic potential of PV systems
- Assess the quality of service: electricity network reliability and quality of electricity provision (disruptions, intermittency, curtailment etc)
- Examine the framework for licensing and operating small scale, distributed electricity generation systems
- Assess the status of development of the PV system components value chain in the country, including investment costs

Early design phase

- Identify the policy targets e.g. overall RES penetration, attract investments and create economic activity, industrial policy, demonstration and familiarization with the technology etc.
- Identify the target group – public buildings, domestic sector, commercial buildings, new-old-retrofitted buildings. This will enable to define the average size of the systems to be supported, the risks and special needs involved and the expected number of installations based on the budget. Link this selection with the policy target.

- Decide on the target area – nationwide or regional. If regional choose an appropriate region based on the outcomes of the preliminary work, taking into consideration administrative capacities and network conditions, regional initiatives (e.g. participation in the Covenant of Mayors) and having in mind the policy targets.
- Get stakeholders involvement at an early stage especially energy regulators, DSOs, regional-local authorities, financial institutions etc.

Design phase

- Set quantitative targets.
- Carefully study the economics. Ensure funding, possibly set economic targets and caps.
- Streamline the process, cover any existing licensing burden
- Design an appropriate communication strategy
- Design a monitoring mechanism