CONNECTING THE SUN

SOLAR PHOTOVOLTAICS ON THE ROAD TO LARGE-SCALE GRID INTEGRATION

FULL REPORT

SEPTEMBER 2012

European Photovoltaic Industry Association

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FOREWORD

THE NEXT STEP FOR PV: CONNECTING THE SUN

In 2011, EPIA published a landmark report showing that solar photovoltaic electricity will, under certain conditions, be competitive against conventional electricity sources across Europe in all market segments by the end of this decade. The study, "Solar Photovoltaics Competing in the Energy Sector: On the road to competitiveness", was conducted with objective input from external consultants and its message was clear: PV is cheaper than many people think.

That remarkable trend continues today. The price of all system components results in a levelised cost of PV electricity that makes this technology competitive even earlier than expected. During times of economic crisis, policy uncertainty and industry consolidation, solar PV has shown impressive market resilience, outperforming all growth forecasts. PV is no longer a niche product. It is an increasingly important source of electricity generation. This means we have to start thinking differently about it.

EPIA's new study, presented on the following pages, is all about taking the next step in the PV industry's evolution on its way to the high penetration levels needed for a 100% renewable energy world. As it becomes a mature and mainstream technology, PV will need to integrate seamlessly into the electricity grid. Yes, this will require some changes from grid operators, from policymakers and from the PV industry itself. But the challenges are not insurmountable. As this report shows, solutions to enable a high penetration of PV are achievable. Although not discussed in this study the mid- and long-term solutions for electricity storage on all levels – local, municipal and national/European – will help to reach our ultimate goals.

People want solar power. And even its harshest critics in the conventional energy sectors will ultimately have to agree that under all scenarios envisioned in the coming decades, solar PV will be a major part of Europe's (and the world's) electricity mix – thanks to its economic advantages.

This makes it crucial to consider the implications of a growing penetration of PV on the electricity grid. With this study, we look at those implications, present realistic options for addressing them, and make clear policy recommendations aimed at facilitating the process.

Solar PV has come a long way in a relatively short time. But now we must consider the steps that will allow us to take full advantage of its enormous potential. With so many stakeholders involved – the PV industry, grid operators, utilities, policymakers and, let's not forget, electricity customers – the discussion in the coming years will not always be easy.

EPIA, as the voice of the global PV industry in Europe, will be a leader in that debate, with accountability, credibility, facts and figures. We stand ready to make the strong case for PV's future.

After all, connecting the sun is not just an achievable goal – it's an essential one.

Dr. Winfried Hoffmann

President
European Photovoltaic Industry Association

EXECUTIVE SUMMARY

PV, A COMPETITIVE SOLUTION FOR THE DECARBONISATION OF EUROPE'S ENERGY SECTOR

The need to avoid irreversible climate change effects has led European Union (EU) countries to commit to reducing greenhouse gas emissions to 80-95% below 1990 levels by 2050. This implies an almost complete decarbonisation of Europe's energy sector by the middle of the century due to the difficulty of cutting emissions in other economic sectors. Achieving this goal will have important consequences for the continent's entire power system.

The Energy Roadmap 2050 presented by the European Commission (EC) in December 2011 and the October 2011 proposals for a renewed energy infrastructure policy offer a unique opportunity to **rethink the evolution of the European energy mix and of its electricity grids** as many investors consider their future plans in our continent.

With a more diversified, variable and presumably electricity-intensive energy mix, the future European electricity system will have to be **more interconnected, more flexible and more decentralised**. The enhancements of the grids, both at distribution and transmission level, will accompany the complete transformation of the electricity sector. They should in particular integrate the rise of distributed generation, including photovoltaic (PV) electricity, which will play a key role in Europe's electricity mix given its competitiveness trajectory. The experience of the last decade has shown that underestimating the full potential of PV leads to sub-optimal situations both from a capacity planning and a network operation point of view. Navigating through the transition towards a more sustainable energy future therefore requires tangible scenario-based forecasts.

This study prepared by the European Photovoltaic Industry Association (EPIA) aims to provide a **holistic vision of how solar electricity will be integrated in the electricity system**. It is based on new EPIA scenarios for the penetration of PV electricity in 2030:

- The **Baseline scenario** envisages a business-as-usual case with 4% of EU electricity demand provided by PV in 2020 and 10% in 2030
- The **Accelerated scenario,** with PV meeting 8% of the demand in 2020, is based on current market trends, and targets 15% of the demand in 2030
- The **Paradigm Shift scenario**, based on the assumption that all barriers are lifted and that specific boundary conditions are met, foresees PV supplying up to 12% of EU electricity demand by 2020 and 25% in 2030

These scenarios have been combined with corresponding wind penetration scenarios. From there, a detailed analysis of balancing needs has been conducted for all 27 EU Member States (based on intermediate scenarios) in order to **better understand system operation challenges**. At distribution level, the study analyses the main constraints associated with high shares of distributed generation. It also considers the effect that grid integration costs will have on the overall competitiveness of PV against other forms of electricity (which had previously been assessed in the EPIA study "Solar Photovoltaics Competing in the Energy Sector: On the road to competitiveness", published in September 2011).

This work involved interviewing several network operators, both at transmission and distribution level, so as to **identify best practices and build recommendations** on the basis of real-world experience. The identified challenges have been answered with existing and potential future solutions, making the best use of PV systems capabilities, which are today vastly underestimated.

PV, AN ACTIVE PART OF THE POWER SYSTEM IN EUROPE

The existing electricity system has been designed to connect large, centralised generating units to large consumers as well as to substations that deliver the power to smaller consumers and, finally, to households. At issue is whether the system can integrate a high number of distributed renewable generators, most of them PV and wind, without creating operational issues and affecting security of supply.

This study examines the electricity system's behaviour under normal as well as extreme conditions (peak electricity demand, minimum electricity demand) and reaches the following conclusions:

- **Large-scale PV integration in the European grid is technically feasible with a high level of security of supply**, even under the most extreme weather and load conditions. With the right measures and investments in place, system reliability can be ensured
- **Solutions exist to address the challenges linked to the increased integration of PV and wind** – their relative variability, their limited dispatchability, and the flexibility requirements they induce in the electricity system:
    - *Variability*: The electricity output of a large number of PV systems is less variable than the output of a single PV system; the larger the number of systems and the area considered, the smaller the variability of the power generated by PV systems in that area. PV forecasting already provides a measure of reliability but is a new tool for PV operators and for Transmission System Operators (TSOs) and needs to be further developed; it will in any case be more precise if large numbers of PV systems are aggregated

    - *Dispatchability*: PV peak production takes place around midday, which is the time when demand also reaches one of its daily peaks; this is an important strength of PV technology. In order to increase PV's contribution to meeting the evening consumption peak, two solutions exist: 1) Shift part of PV electricity in-feed from the day to the evening with the help of storage facilities; or 2) Shift part of the evening consumption to earlier hours of the day with Demand Side Management (DSM) measures. On a seasonal basis, the complementary output of PV and wind can reduce the need for back-up generation. Finally, PV's unique ability to produce electricity close to where it is consumed alleviates the need for additional massive investment in new transmission lines
    - *Flexibility*: To ensure adequate system flexibility in the future, a proper mix of assets (interconnections, storage, DSM, flexible generation) should be used. The capacity of currently installed flexible sources to ramp up and down with fluctuations in demand will be sufficient until 2020
- To fully benefit from carbon-free electricity sources, **storage and DSM solutions should be implemented** soon and progressively, in order to avoid limiting the full exploitation of PV and wind electricity at the European level in 2030
- **Daily storage is well-suited for PV peak generation**

PV AND THE FUTURE OF THE DISTRIBUTION NETWORK

As an extension of the transmission network, distribution grids must be managed to maintain the voltage level within specified limits and deliver a high quality of power.

Current distribution grids have been designed to transport the required power from the higher voltage level to the connected demand. Consumer electrical appliances are able to work only within certain margins for frequency and voltage. To avoid their degradation, system operators have to ensure that every consumer has access to secure and quality electricity.

The distribution network – which comprises Low Voltage (LV), Medium Voltage (MV) and in some countries High Voltage (HV) levels – has been designed to connect with small consumers: households, Small and Medium Enterprises (SMEs) and small industrial sites. The rise of distributed generation, such as PV, in the distribution grid now means that electricity flows in two directions: from the transformer to the consumer, but also vice-versa.

After assessing the technical feasibility of cost-optimal solutions to integrating high amounts of variable renewable electricity at the distribution level, this study finds that:

- Already today, several Distribution System Operators (DSOs) are managing significant penetrations of distributed generation in Europe; **there are today no technical limits to large-scale PV integration in the distribution networks**
- Nevertheless, to avoid the need for costly interventions in the future, **DSOs should implement "smart solutions"** allowing for even more and smarter PV participation in system operation, including: grid monitoring, self-regulated or controlled distribution transformers and decentralised storage
- These solutions should **build on a better assessment and on a simulation of the impact on the grid of a rising share of distributed generation** that should be conducted on a regular basis
- This will require modifying today's distribution grid design and management; when distributed electricity cannot be locally consumed, there is a risk that the flow can be reversed

- **PV can already provide significant grid support capabilities, including active power reduction, Fault Ride-Through (FRT), and voltage support**; these capabilities are currently vastly underrated
- Curtailment should not be considered the silver-bullet solution for increasing the hosting capacity of the distribution grid, given that PV systems can also provide voltage support at virtually no cost
- **Enabling a higher level of self-consumption will also reduce system congestion**
- To reduce peak production and/or consumption, strategies will have to be implemented using DSM or storage at the household or local level. Standards for inverters and for communication infrastructure (including smart meters) will enhance PV system capabilities and ensure a cost-effective grid integration of PV

IMPACT OF GRID INTEGRATION ON PV COMPETITIVENESS

Until now, the PV market has been helped in its development by financial support schemes such as Feed-in Tariffs, but these will be progressively phased out. EPIA's 2011 report, "Solar Photovoltaics Competing in the Energy Sector: On the road to competitiveness", showed that a certain level of **competitiveness of PV is approaching in many European markets**. Since the publication of that study, production overcapacity on the PV market has driven prices down faster than expected, bringing some market segments in specific countries close to the first level of competitiveness already. But the question about the future remains: How will grid integration challenges affect PV competitiveness?

The study reaches the following conclusions:

- The costs associated with increased PV participation in system operation will, depending on the measures involved, have an impact on PV competitiveness
- The costs of widespread deployment of state-of-the-art capabilities in PV inverters will be negligible
- However, curtailment would have a negative impact on the revenue stream of PV system owners, even when the cuts are limited; it should therefore be used only in extreme grid situations and after all other technically more efficient options have been executed
- If PV system owners were required to pay grid costs and taxes even when self-consuming electricity, PV competitiveness would be delayed by a certain number of years depending on the market segment and on the country
- The increasing competitiveness of PV systems will also allow for more room to invest in storage; the combination of PV and storage will become more and more economically attractive as the electricity savings from storage will exceed the revenues from the electricity sold on the wholesale market
- A combined PV/heat pump system today represents one of the best ways to optimise self-consumption and therefore the competitiveness of PV

POLICY RECOMMENDATIONS

There are virtually no technical limits to a 15% level of PV integration into the system. But **integrating large shares of distributed generation in the electricity system requires a series of complementary measures**. Not all of them are of a technical nature. A lot has to be done also to ensure a closer collaboration among TSOs, DSOs, and conventional and renewable players in order to identify cost-optimal solutions. PV in itself will be one of these solutions, through the provision of grid services and, in extreme cases, contracted curtailment.

System operation will become more complex, since PV and wind together will exceed occasionally the absorption capacity of the network. To maintain system security, it will be crucial to fully exploit and develop system flexibility. Here again, PV will be part of the solution, in combination with storage and DSM.

As Europe plans investments in new energy infrastructure, these evolutions should form the pillars of an integrated approach in which modification of the electricity system and development of the infrastructure are seen together.

Such an approach requires achieving four key policy goals:

- Create a continuum among TSOs, DSOs and distributed generation
- Increase overall system flexibility
- Implement a new approach to overcome bottlenecks in the distribution grid
- Ensure a fair financing of all parties

ON THE ROAD TO LARGE-SCALE GRID INTEGRATION

The increasing role played by variable Renewable Energy Sources (RES), including PV, in Europe's electricity system presents challenges for grid operators. However, in many ways, PV is already providing solutions – meeting a growing share of electricity demand at increasingly competitive cost without creating undue strain on the power system.

Even though it is not by nature dispatchable, PV electricity is decentralised and can be produced close to where it is consumed. Furthermore, it has a strong seasonal match with wind (since PV is able to meet more peak demand in summer, while wind is more productive in winter) and an average daily match (since PV produces during the day with a peak around midday, while wind produces more during less sunny hours); these two energy sources together can provide up to 45% of Europe's electricity needs in 2030. When viewed together (and when considered from a Europe-wide perspective rather than a local or national one), they provide realistic solutions to the technical challenges involved in integrating this large share of renewable electricity. In any case, these solutions are achievable, especially when combined with tools to increase the flexibility of the electricity system – such as storage and DSM.

Europe's electricity demand is increasing. In the context of Europe's decarbonisation goals, this power will have to come from more variable RES. **As European policymakers consider their options for investing in new and more efficient grid infrastructure, they should take into account the benefits that PV is already producing and, more importantly, plan for the greater benefits it is capable of producing in the future.**

In that way, **PV can deliver on its promise as a major contributor to meeting Europe's energy, environmental and economic goals for the coming decades.**

1

PV, A COMPETITIVE SOLUTION FOR THE DECARBONISATION OF EUROPE'S ENERGY SECTOR

1.1. Introduction

The need to avoid irreversible climate change effects has led EU countries to commit to reducing greenhouse gas emissions to 80-95% below 1990 levels by 2050 (in the context of necessary reductions by developed countries as a group). This implies an almost complete decarbonisation of Europe's energy sector by the middle of the century due to the difficulty of cutting emissions in other economic sectors. Achieving this goal will have important consequences for the continent's power system.

The Energy Roadmap 2050[1] presented by the EC in December 2011 and the October 2011 proposals[2, 3] for a renewed energy infrastructure policy offer a unique opportunity to **rethink, as Europe considers these major new investments, the evolution of the energy mix and of the electricity grids**.

These enhancements, both at distribution and transmission level, will accompany the complete transformation of the electricity sector to a smarter, more efficient and reliable power system. They should in particular integrate the rise of distributed generation and of PV electricity, which will play a key role in Europe's electricity mix given its competitive trajectory.

This study aims to provide a **holistic vision of how solar electricity will be integrated in the electricity system**. It is based on new 2020 and 2030 EPIA scenarios, which have been combined with corresponding wind penetration scenarios[4]. From there, a detailed analysis of balancing needs has been conducted for all 27 EU Member States in order to better understand system operation challenges. At distribution level, the study analyses the main constraints associated with high shares of distributed generation. It also considers the effect that grid integration costs will have on the overall competitiveness of PV against other forms of electricity (which had previously been assessed in the EPIA study "Solar Photovoltaics Competing in the Energy Sector: On the road to competitiveness", in September 2011).

This work involved interviewing several network operators, both at transmission and distribution level, so as to identify best practices and build recommendations on the basis of real-world experience. The identified challenges have been answered with existing or potential future solutions, making the best use of PV systems capabilities, which are today vastly underestimated.

1.2. Evolution of the European energy mix: Where are we going?

Several scenarios for decarbonising the European energy sector – in line with the EU's long-term emission reduction target – have been published in recent years by a wide range of stakeholders. A recent "Metastudy analysis"[5] on 2050 energy scenarios indicates that all of them present some similarities for the electricity sector. Among them, three structural evolutions will have a direct impact on Europe's electricity grids: There will be a greater demand for electricity, a greater contribution of variable renewable technologies, and more reliance on distributed generation.

- **More electricity:** The modelling exercise conducted by the EC in its Energy Roadmap 2050 shows that electricity will double its share in final energy demand from current levels to 36-39% in 2050. This reflects the increasing use of electricity in transport and to cover heating and cooling needs, especially in the building sector
- **More variability:** This greater reliance on electricity will be supported by a massive contribution of variable RES, in particular PV and wind, to the new electricity mix: up to 65% by 2050 according to the EC's Energy Roadmap and potentially even more. Generally speaking, RES play a major role in all identified pathways, representing at least 55% of the gross final energy consumption and between 59% and 86% of electricity generation in 2050
- **More distributed generation:** Along with the classical "top-down" way of producing electricity through centralised power stations, an increasingly important share of renewable electricity will be provided by distributed generation. PV technology, being modular and scalable, will bring a substantial contribution to the overall EU power production

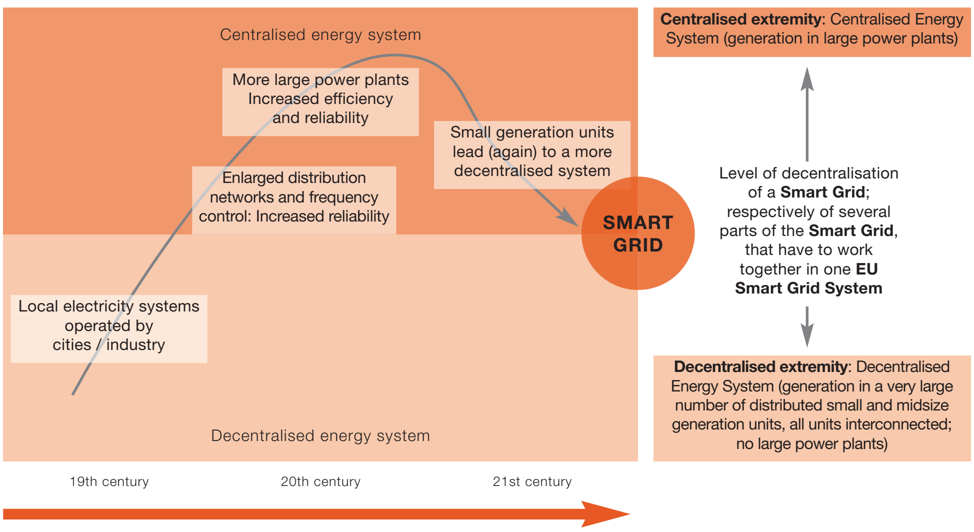
1.3. Adapting the electricity system to a new paradigm

All the evolutions described above will have profound consequences for the way the electricity system is developed and managed. The future system will have to be more interconnected, more flexible, and more decentralised.

- **More interconnected:** A real European single energy market is a key to realising this new paradigm. It will provide consumers and businesses with more and better products and services, more competition, and more security of energy supply. Several initiatives already under way at European level aim at enhancing the integration of national power systems and completing the internal electricity market by 2014 (such as network codes and coordination of TSOs via Ten Year Network Development Plans). In addition, EU decision makers are now discussing new ways to facilitate grid investments. Common rules for streamlined permitting procedures and dedicated EU financial support for non-commercially viable projects will support such expenditures. These evolutions are necessary to achieve a more interconnected European power system. But they will have to be part of an integrated view on transmission and distribution, in order to respond to the second feature of the future electricity system: flexibility

- **More flexible:** Integrating the increasing shares of PV and wind in the EU electricity mix requires enhanced system flexibility to compensate for their variable output throughout the day and the year. As recently acknowledged by the International Energy Agency (IEA)[6], flexibility is not a new requirement caused by the rise in variable renewable capacities. Europe's existing electricity system is already able to cope with flexibility, but these assets will need to be more effectively exploited and further developed
- **More decentralised:** Today's largely centralised electricity system developed over the past century as the result of a number of conditions. Originally it was decentralised, with plants feeding power into local grids operated by cities or industries. Later, the availability of capital, coupled with technology improvements that allowed for large-scale frequency/voltage control, favoured the deployment of a system based on large power plants. But going forward the needs are different. Technological developments, the progressive rise of distributed generation and the increasing need to manage the system close to consumption points all require a shift towards a more decentralised electricity system (Figure 1). Therefore, decentralised and centralised generation can co-exist; smart grid development will enhance their complementarity

Figure 1 - Historical evolution of the electricity system in Europe



source: EPIA, based on Siemens analysis

In this transition, **a new figure will emerge: the "prosumer", producing and consuming his or her own electricity**. By covering on-site part of the final user's electricity needs, PV systems will generate new opportunities. Such decentralised electricity generation will have to be better incorporated in future strategies.

1.4. The importance of properly integrating the rise of PV

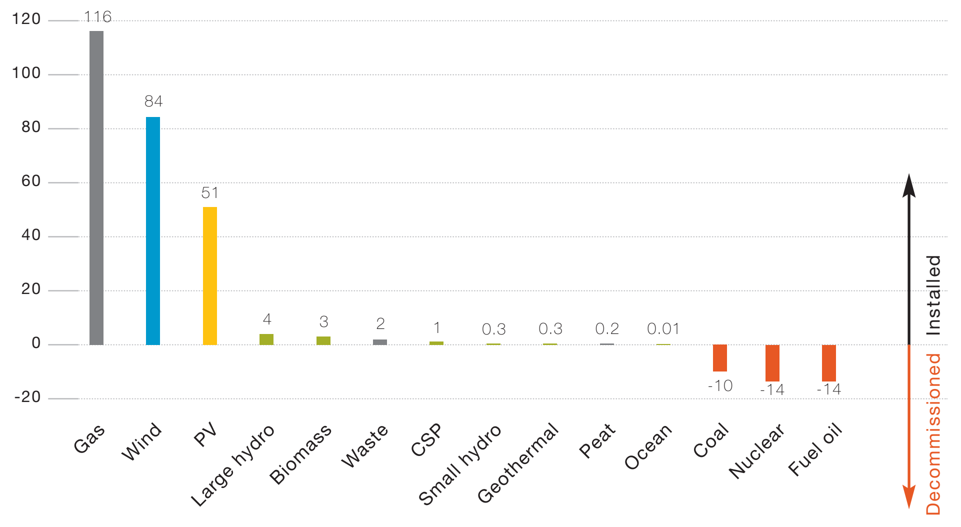
1.4.1. Time for a reality check

Support schemes put in place by visionary policymakers in several European countries, along with the fast price decline in PV panels, have spurred strong growth in PV markets over the past few years. From 2009 onwards, PV placed among the top three electricity technologies installed in Europe (Figure 2). In 2011, with 21.9 GW of new systems connected to the electricity grid, PV became the number-one electricity technology installed in Europe, ahead of wind and gas. **PV cumulative installed capacity in Europe at the end of 2011 corresponded to 51.7 GW, producing enough electricity to supply over 15 million European households**. Solar PV now provides a significant share of Europe's electricity mix, covering 2% of the demand and roughly 4% of the peak demand.

Did you know?

In Italy, at the end of 2011, PV already covered 5% of the electricity demand, and more than 10% of the peak demand. In Bavaria, a federal state in southern Germany, the PV installed capacity amounts to 600 W per inhabitant, or three panels per capita. In around 15 regions in the EU, PV covers on a yearly basis close to 10% of the electricity demand; in Extremadura, a region of Spain, this amounts to more than 18%.

Figure 2 - Net generation capacity added in the EU 27 in 2000-2011 (GW)



source: Based on EPIA and EWEA figures, 2012

This rapid PV market deployment has taken many stakeholders by surprise. Indeed, PV deployment potential has been consistently underestimated in recent years in Europe.

Such underestimation or lack of anticipation is also reflected in the National Renewable Energy Action Plans (NREAPs) developed by the Member States in the context of the Renewable Energy Directive (2009/28/EC). Already today, six Member States have reached their 2020 target for PV, and seven others are expected to reach it by 2015. According to EPIA calculations, **the potential for 2020 is at least twice as high as the levels foreseen in the NREAPs, pushing towards 200 GW capacities or even more in Europe**.

This lack of foresight can lead to sub-optimal situations in network operation. For example, in Germany the settings for over-frequency disconnection in case of extreme events were reduced in 2005 from 50.5 Hz to 50.2 Hz in order to ease distribution network operation. This decision reflected the belief that PV installed capacity would remain marginal and could be disconnected without any impact on the system. But the rapid growth of PV installed capacity in Germany showed that this approach was not sustainable, and has triggered a costly retrofitting of several hundred thousand existing installations.

The message is clear: A forward-looking policy is needed to ensure that Europe's decarbonisation strategies will be supported by a corresponding vision of grid evolution. **It is therefore crucial that policymakers and network operators properly consider the real potential of PV in the medium to long term**. Regular updates will help stakeholders to navigate through the transition.

1.4.2. Assessment of PV's competitiveness

Future deployment of PV is closely linked to its competitiveness. While the PV market has developed until now with the help of direct financial support schemes, no one expects this situation to last forever. While in the medium to long term we are likely to see a return to the normal price experience curve, in the short term, production overcapacity on the PV market has driven prices down faster than expected. This is bringing some market segments in some countries close to a certain level of competitiveness.

The gap in competitiveness between PV and conventional energy sources is closing quickly. This will lead to a progressive phasing out of the direct financial incentives that have helped compensate for it.

1.4.2.a What is competitiveness?

Competitiveness is analysed here either as "dynamic grid parity", when comparing PV's generation cost (the Levelised Cost of Electricity, or LCOE) with PV revenues (earnings and savings); or as "generation value competitiveness", when comparing PV's generation cost to that of other electricity sources (for complete details on the methodology used, consult EPIA's study "Solar Photovoltaics Competing in the Energy Sector: On the road to competitiveness", September 2011 and Annex A of this report).

Two perspectives should be distinguished when analysing competitiveness:

- **For the residential, commercial and industrial segments** – involving the local consumption of PV electricity, when a user goes from being a consumer to a "prosumer" – **dynamic grid parity is considered**
- **For large industrial and ground-mounted segments** – involving the generation of PV electricity for grid injection – **generation value competitiveness is used**; this involves comparing the generation costs of PV and a standard generation technology (in this case Combined Cycle Gas Turbine (CCGT) power plants). "Wholesale competitiveness", which compares PV's LCOE with wholesale electricity prices, requires examining much more complex boundary conditions (such as market design) that are not considered in the framework of this study

1.4.2.b Dynamic elements of competitiveness

PV's competitiveness is evolving depending on different dynamic parameters that can affect either the generation cost of or the revenue stream from PV. Since our September 2011 report, some of the values of these parameters have changed, including:

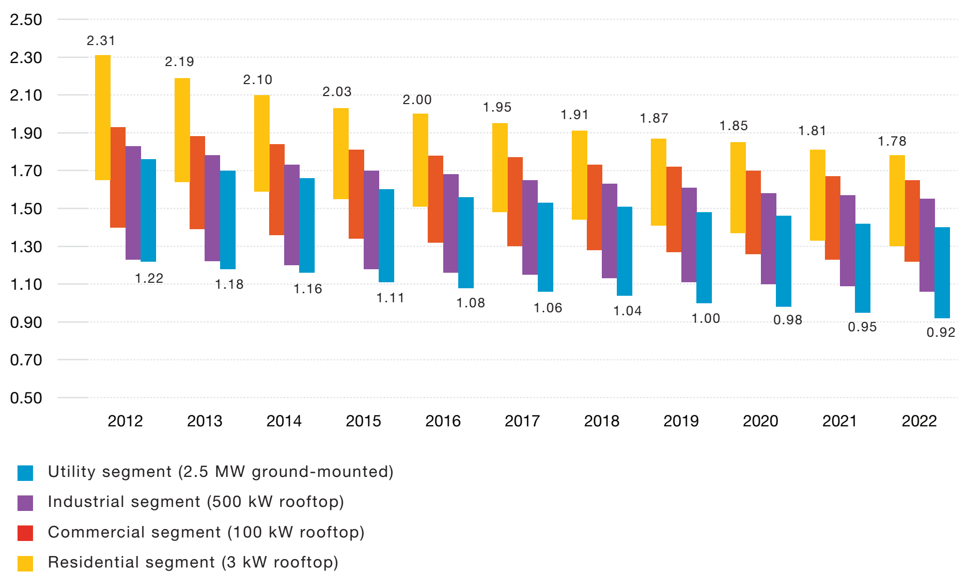
Dynamic elements affecting PV's LCOE

- System price evolution: Since 2011, system prices have decreased dramatically due mainly to a drop in module prices; this is expected to affect the evolution of PV system prices (Figure 3) in the medium to long term, and thus PV's competitiveness. Two scenarios were considered, one with expected low prices and one with higher prices. Increased participation of PV in power system management will require additional features that can have an impact on the price of a system. This will be evaluated in greater detail in Chapter 4
- Cost of capital evolution: Europe's financial crisis is having a severe impact on the cost of financing PV projects. This must be taken into consideration, given that the cost of capital is one of the important factors affecting PV's LCOE. Two assumptions have been taken into account: a low Weighted Average Cost of Capital (WACC) remaining between 4.4% and 8.2% depending on the segment, and a high WACC ranging from 7% to 11%

Dynamic components affecting PV revenues

With a higher penetration of PV, self-consumed electricity might be exposed to increased grid costs and taxes. This would affect the revenue stream and thus the competitiveness of the system. This impact will be analysed in more detail in Chapter 4.

Figure 3 - Scenarios for future PV system prices evolution (€/W)



source: EPIA, 2012

The difference in solar irradiation from north to south in a particular country also has an effect on competitiveness, but it is not an element that changes over time.

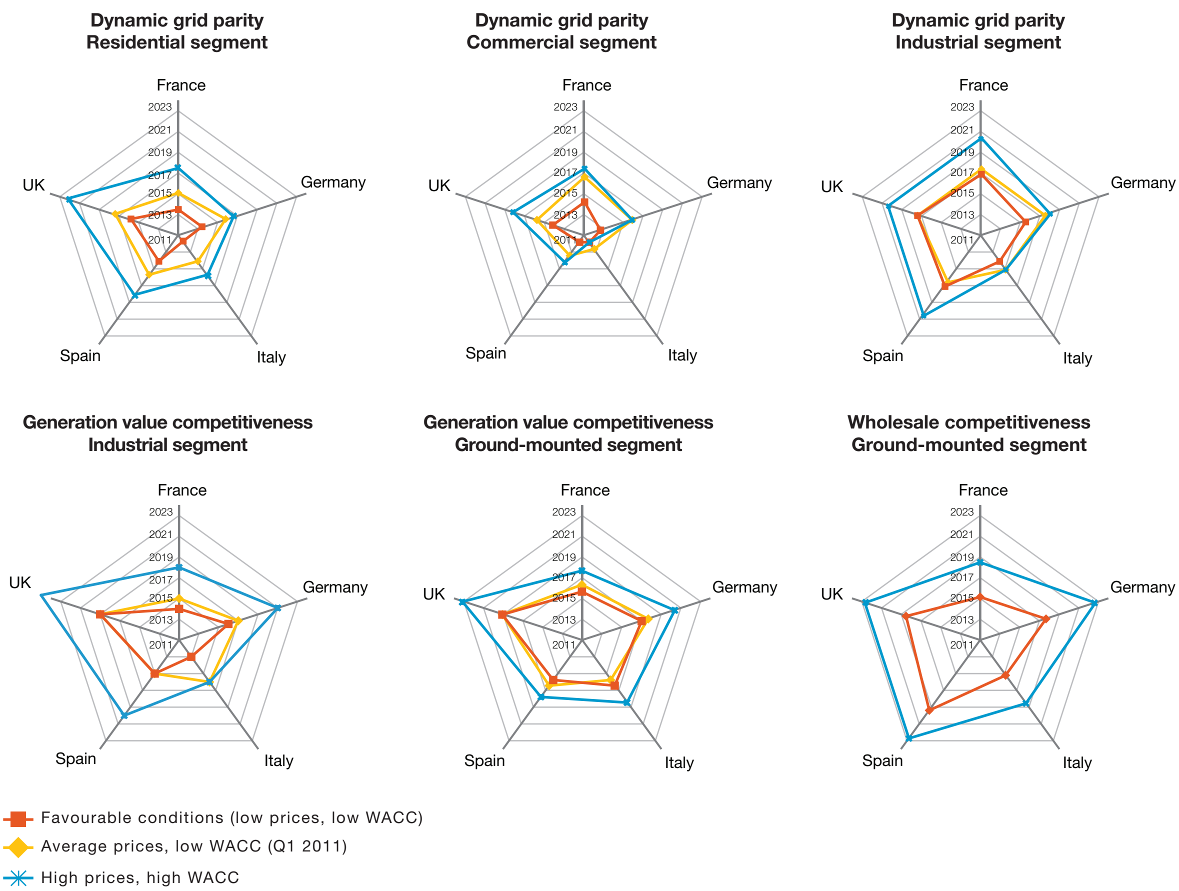
1.4.2.c Status of PV competitiveness in 2012

Before analysing the impact of grid costs on PV competitiveness, it is essential to assess the status of PV's competitiveness as of today. A thorough analysis was conducted in 2011; due to important changes since then, some values have evolved much more quickly compared to original assumptions.

Annex A.3 includes a detailed analysis of the potential impact of each parameter on PV's competitiveness in the medium to long term. This involves assessing the impact of the cost of capital evolution and the decline of system prices. Figure 4 below shows the impact on competitiveness of considering a high or low cost of capital scenario and/or using the high or low price scenarios. These results are compared to those of EPIA's 2011 analysis. It also shows that a higher cost of capital can delay competitiveness significantly.

The evolution of these dynamic parameters confirms the findings from 2011: **PV can be competitive in each segment in Europe by 2020, but will be competitive much earlier in some segments in specific countries**. Such a competitiveness trajectory provides additional guidance for medium- to long-term scenarios.

Figure 4 - Impact on competitiveness dates of dynamic parameters (cost of capital and system prices)



source: EPIA, Solar Photovoltaics Competing in the Energy Sector, September 2011 and EPIA, 2012

1.4.3. Forecasts and scenarios

EPIA's "SET For 2020" study, published in 2009, showed that PV could – under certain conditions – cover from 4% to 12% of Europe's electricity demand in 2020.

Three years later, PV market development in Europe has confirmed that the range of these scenarios was in line with the reality of the market. EPIA has built its own forecasts and scenarios on these real market data, as collected every year in the EPIA Global Market Outlook analysis.

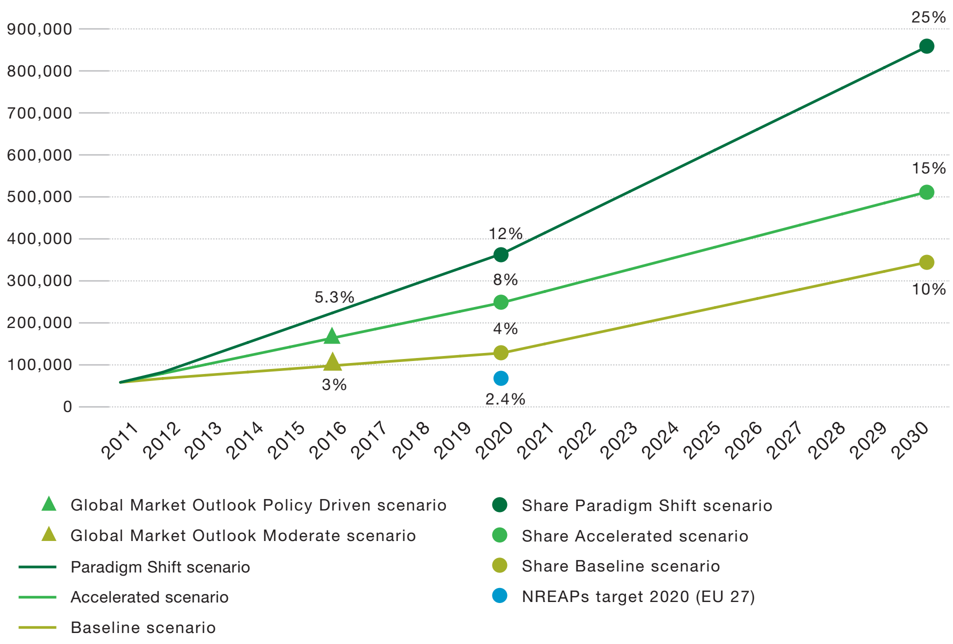
Scenarios for 2020 and 2030

Taking into account recent market developments, EPIA updated the "SET For 2020" scenarios and developed possible 2030 targets, as described below (Figure 5 and Annex B, table 7):

- The **Baseline scenario** envisages a business-as-usual case with 4% of the electricity demand in the EU provided by PV in 2020 and 10% in 2030
- The **Accelerated scenario** with PV meeting 8% of the demand in 2020, is based on current market trends, and targets 15% of the demand in 2030
- A third case, based on the assumption that all barriers are lifted and that specific boundary conditions are met, is called the **Paradigm Shift scenario**. This foresees PV supplying up to 12% of EU electricity demand by 2020 and 25% in 2030

This study focuses on the "Accelerated" 15%-by-2030 scenario.

Figure 5 - Projected penetration of PV in Europe* until 2030 (MW)



source: EPIA, 2012
* Europe includes here the EU 27, Turkey, Norway and Switzerland

Highlighting the true potential of PV in Europe

PV technology has shown an impressive resilience to harsh market conditions in 2011 and 2012. Thanks to its decentralised nature and its ability to lower prices due to its modularity, PV continues to outperform all growth forecasts.

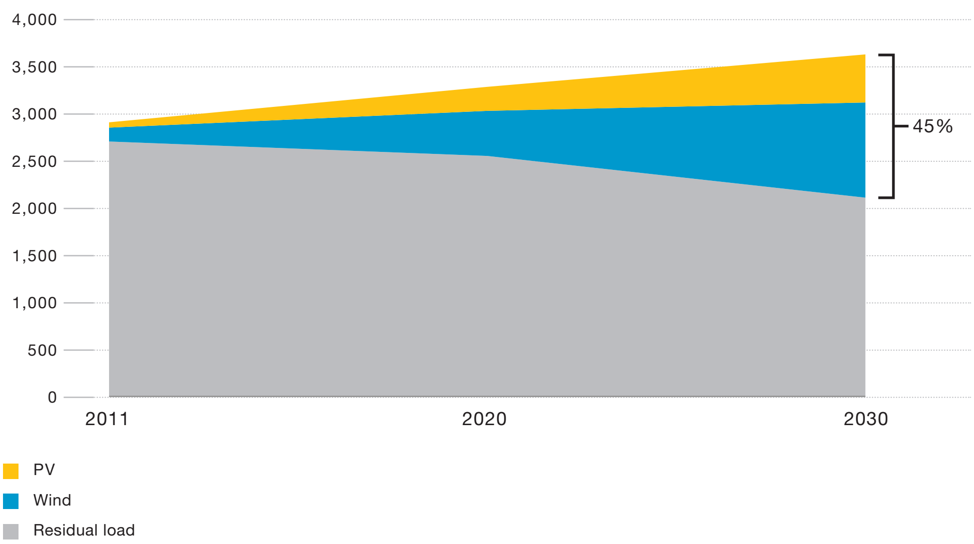
The 15% penetration scenario (Accelerated scenario) considered in this study represents a very realistic view of market development in Europe until 2030. It assumes roughly that the same absolute market conditions observed in Europe in 2011 will be sustained through the coming two decades.

The "SET For 2020" study published by EPIA in 2009 estimated that PV could reach up to 12% of Europe's electricity demand by 2020. This high-growth, Paradigm Shift scenario highlighted at that time the complex conditions required to reach such a goal. From 2008 to 2010, market growth in Europe reached levels compatible with such a high scenario. As a result, this Paradigm Shift scenario remains a possible future for PV until 2020. What makes this scenario useful is that the set of preconditions necessary to reach 12% are similar regardless of the date at which this level of penetration is reached. In particular, deploying grid integration solutions as described in this study will unleash the real potential of PV and make the 25% penetration scenario a realistic one.

While this study "Connecting the Sun: Solar photovoltaics on the road to large-scale grid integration" focuses on the 15% scenario in 2030, this level of penetration does not represent a final goal but rather a milestone towards higher levels. The question is: When can a 25% penetration be reached? In 2030 or later?

Considering the wider context of the evolution of the EU electricity mix, this report also takes into account the contribution of the two major variable renewables in its scenarios: PV and wind, which can work together effectively to meet a significant share of Europe's electricity demand (Figure 6). The assumption of 30% wind penetration comes from the European Wind Energy Association's figures (Annex B, table 8). This exercise will help to understand better certain needs of the future power system.

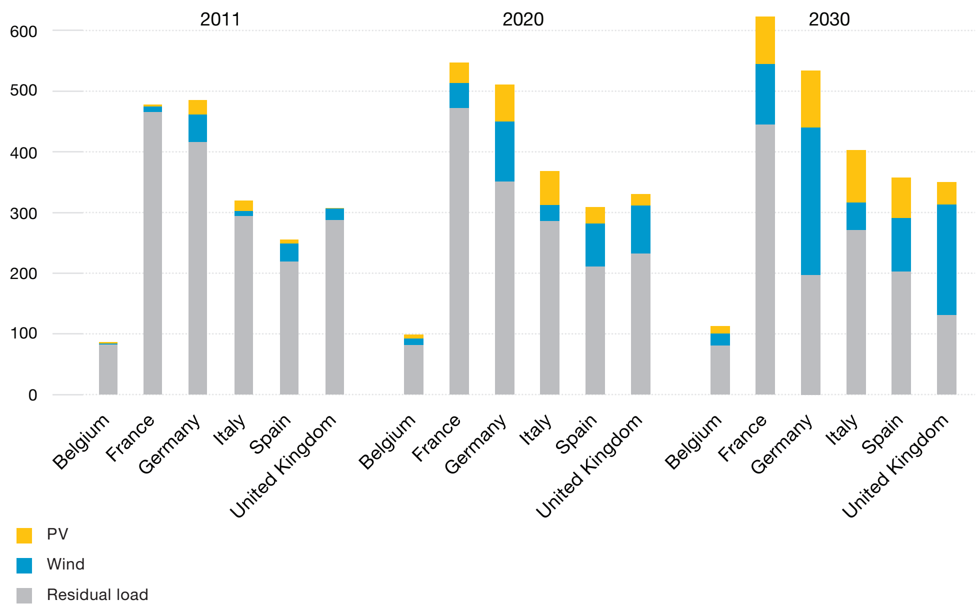
Figure 6 - Projected PV and wind contribution to final EU 27 electricity demand until 2030 (TWh)



source: Based on EPIA, EWEA and Primes Model figures, 2012

Scenarios were developed for all 27 EU Member States. However, this paper will focus on six key countries: Belgium, France, Germany, Italy, Spain and the United Kingdom (Figure 7). These countries are among the largest electricity markets in Europe, with various combinations of solar irradiance and different market conditions.

Figure 7 - Projected PV and wind contribution to final electricity demand in 6 key countries until 2030 (TWh)



source: Based on EPIA, EWEA and Primes Model figures, 2012

These updated 2020 and 2030 scenarios are intended to guide electricity stakeholders and policymakers towards a high penetration of PV in Europe's evolving electricity mix. They have served as the basis for identifying grid integration challenges, both at transmission and distribution levels.

1.5. Conclusions

Scenarios on the market share of PV that were defined some years ago, such as the NREAPs, need to be updated by more realistic forecasts. **PV will represent a significant share of Europe's future electricity mix, and its imminent competitiveness will contribute to making it a mass-market solution in the mid-term future.**

A cost-optimal grid development process (both at distribution and transmission level) must therefore be based on a proper assessment of PV's characteristics and real potential.

The next chapters of this report outline the most cost-effective solutions for integrating PV in the electricity network.

2

PV, AN ACTIVE PART OF THE POWER SYSTEM IN EUROPE

2.1. Introduction

The expected increase of solar PV in the European energy mix, as described in Chapter 1, is one of many factors that will require modifications in the electricity system at national and European levels. This chapter assesses whether the integration of high amounts of variable RES and PV in particular can be achieved while maintaining the stability of the electricity system and examines how the system behaves under extreme conditions (peak electricity demand, minimum electricity demand).

The existing electricity system has been designed to connect large, centralised generating units to large consumers as well as to substations that deliver the power to smaller consumers and, finally, to households. At issue is whether the system can integrate a high number of distributed renewable generators, most of them PV and wind, without creating operational issues and affecting security of supply.

All results presented in this chapter are based on a numerical model assessing at national and European level the behaviour of the future electricity system with a high share of VRE. Further details on the methodology and the assumptions can be found in Annex C. The results allow an assessment of the challenges facing management of the transmission grid as well as existing solutions that can be implemented.

The primary task of a TSO is to ensure the stability of the electricity system in the control zone it manages. This control zone can be a large region or a country. System-wide the TSOs are obliged to respect the balancing requirements of other TSOs and coordinate in order to have a balanced, interconnected system.

The stability requirement is the cornerstone of electricity system development and will continue to be so in the coming years and decades. The current system, based mainly on fossil fuels, nuclear power and large hydro, has slowly adapted and reached the high level of reliability that is evident today. The increasingly high shares of PV and wind electricity have raised questions about what has to be done to maintain it.

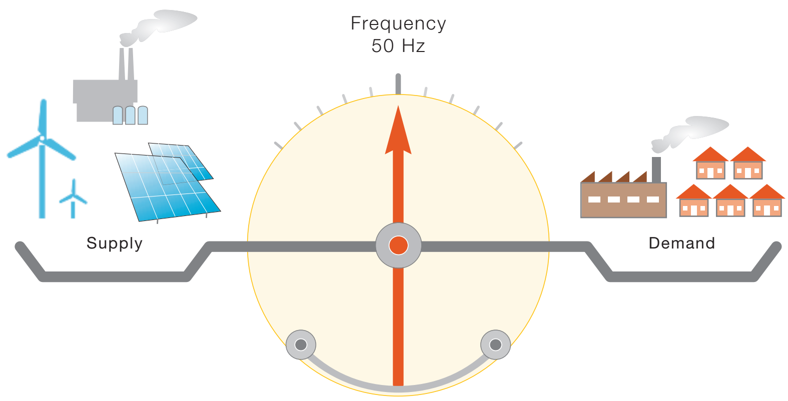
In order to ensure safe grid operation and high power quality, the electricity frequency must be maintained close to its nominal value, which in Europe is 50 Hz. The frequency is determined by the balance of demand and generation. An imbalance immediately results in a deviation from the target value: The frequency decreases when demand exceeds generation and increases when generation is higher than the demand. Therefore supply and demand must be balanced at all times (Figure 8).

The frequency is permanently monitored by the system operator, who contracts reserve energy and calls for balancing power in case of imbalances. This balancing power can be positive and negative depending on what imbalance is seen. The need to constantly balance the system is not new. It has always been the case that high variability of demand, unplanned outages of conventional power plants or wrongly forecast demand levels could result in a demand-supply imbalance. This challenge, however, has become more important with the integration of decentralised or weather-dependent renewable generators.

Until the massive penetration of Variable Renewable Energies (VRE), such as PV or wind, electricity generators were dispatchable, meaning their power output could be adjusted according to demand. They were controlled by the TSO on a permanent basis to meet demand and maintain the stability of the entire electricity system. However, VRE by nature are not dispatchable since they cannot always produce on demand. Moreover, actively managing power output of PV and other small generators requires the ability to control them, something not currently possible. Finally, while VRE can technically provide some flexibility, **the need to develop a more sustainable energy mix requires maximising the injection of renewable electricity**.

These concerns have been relatively minor with a low penetration of PV in the past; today and especially tomorrow they must be reconsidered as high levels of penetration are reached. This chapter addresses these issues, and shows that **tools are available to allow a stable operation of the electricity system and to ensure security of energy supply even with a high penetration of VRE**. It also looks at what mitigation measures will be required to accommodate PV development, and shows how the current level of reliability in Europe's electricity network can be maintained.

Figure 8 - Balancing demand and supply at any point around 50Hz



source: EPIA, 2012

2.2. Turning variable into predictable: integrating PV in the electricity mix

2.2.1. What is variability

Although at the system level a PV power plant is one of the simplest generation units (no fuel, no heavy rotating machines), the variability of PV electricity is often highly misunderstood. The unique generation characteristics of PV electricity include the variable nature of solar resources and the overall weather conditions that could affect PV production (snow cover, temperature, etc.).

Variability usually implies uncertainty, which can raise concerns for many stakeholders. However, tools already exist that can sufficiently reduce the uncertainty associated with PV production. This helps to enable the reliable integration of large amounts of variable RES such as PV.

While the production of a single PV unit can go up and down quickly under certain weather conditions, this has an insignificant effect on the overall electricity system. For this reason, **PV should be considered as a variable source of electricity rather than an intermittent one**.

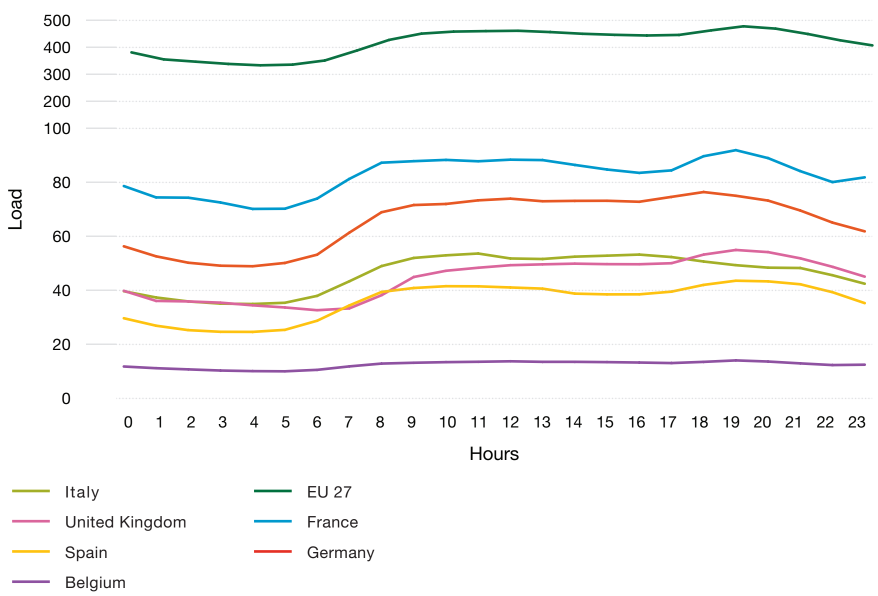
Understanding the distinctive production characteristics of PV power plants and their interaction with the rest of the power system is essential to integrating a large amount of PV into the grid.

2.2.2. Managing variability is not a new concept

Variability at the consumer level has long been a challenge for the power system. Electricity demand varies considerably within minutes, hours, days, weeks, seasons and years. It is also highly dependent on weather conditions, daylight conditions, customs, holidays, events, and so on.

Figure 9 represents the daily aggregated load per key country. The load per region or per neighbourhood is typically much more variable. This challenge has been addressed so far by aggregating the load and by using dispatchable power plants to ensure system operation.

Figure 9 - Typical daily electricity demand profile in 6 key countries and the EU 27 (GW)



source: EPIA, 2012

Did you know?

Load can vary for strange reasons. During the World Cup football semi-final in 1990, England's national grid experienced a sudden surge of 2.8 GW in demand within less than half an hour between the end of extra time and the penalty kicks. The reason: people were switching on their tea kettles.

2.2.2.a Impact of the variability of PV electricity production

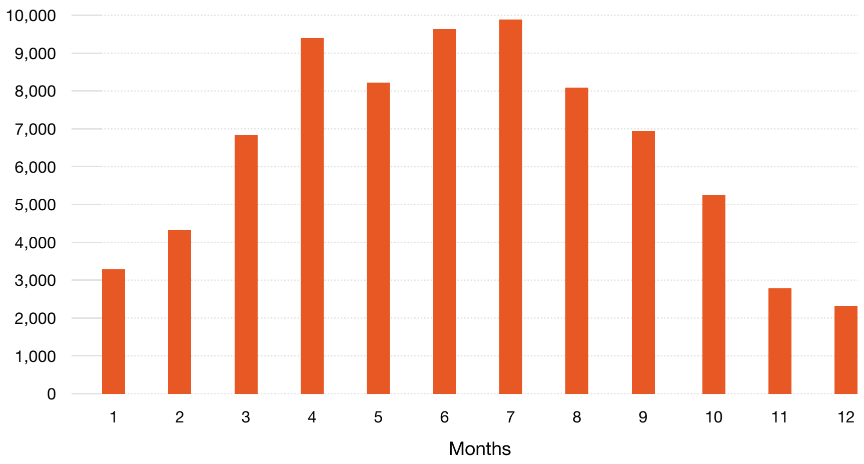
Variability can be measured based on time horizons and/or spatial dimensions. The impact on system operation can be quite different, requiring different approaches, tools and relevant costs.

For reliable PV grid integration, short-term variability is the factor that raises the most concern for the network operation. Potential rapid changes of PV production – whether measured in seconds, minutes or hours – need to be taken into account to secure the supply and maintain a balanced system at 50 Hz. In those cases the network operator has to be able to balance the demand by having sufficient reserves from dispatchable power plants (ancillary services).

Long-term variability (seasonal) as seen in Figure 10 also has an impact on unit commitment and scheduling. Grid operators should be able to find the lowest-cost dispatch of available generation resources (conventional units and aggregated variable sources) to meet the demand. **Long-term variability of PV does not challenge system operation since the network operator can prepare in advance the generation adequacy and the balancing needs**.

When it comes to the spatial dimension, variability can have consequences very locally (on a single line, for example) or on a regional scale (the balance of consumption and production in a particular area). But predictability increases as the area considered increases, so it can be helpful for system operators to emphasise this in considering their balancing needs.

Figure 10 - 2011 monthly average PV production in the EU 27 (MW)



source: EPIA, 2012

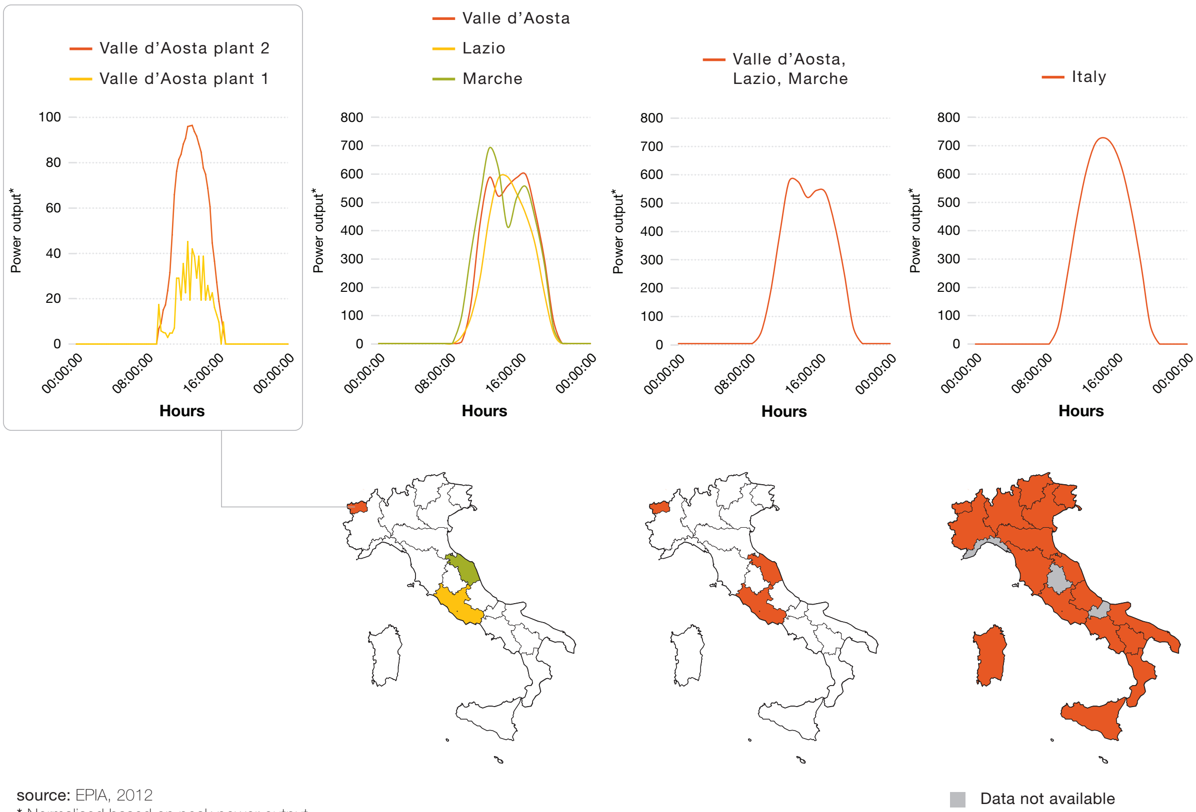
2.2.2.b Smoothing effect in large balancing areas

Enlarging balancing areas and aggregating the dispersed PV output of hundreds and thousands of different PV units has proven effective at reducing uncertainty and therefore facilitating the balancing requirement.

Figure 11 shows how PV output is smoother and more predictable when observed over larger areas – in this case in Italy. While the PV generation for two identical units installed in the same region (Valle d'Aosta) shows a large variability due to cloud effects (around 60% difference), aggregating the PV output of the whole region has a significant smoothing effect, as clouds do not pass over all sites at the same time. In this case again there is a strong dip at about 14:00; however, this dip diminishes when the overall output of three regions is considered. The output of all PV systems in Italy resembles a smooth, and therefore predictable, "bell curve".

The same effect can be seen for all European countries and it is independent of the local weather conditions or the differences in weather patterns between south and north. For this reason it is also **easier to forecast PV generation over a region or a whole country with a significantly higher accuracy than to forecast the PV generation of smaller fleets**. The smoothing effect will be even greater when considering a strong interconnected European area.

Figure 11 - Comparison of daily PV variability (plant, region and country level) - Example of Italy (kW)



source: EPIA, 2012
* Normalised based on peak power output

2.2.2.c Smoothing effect in different time horizons

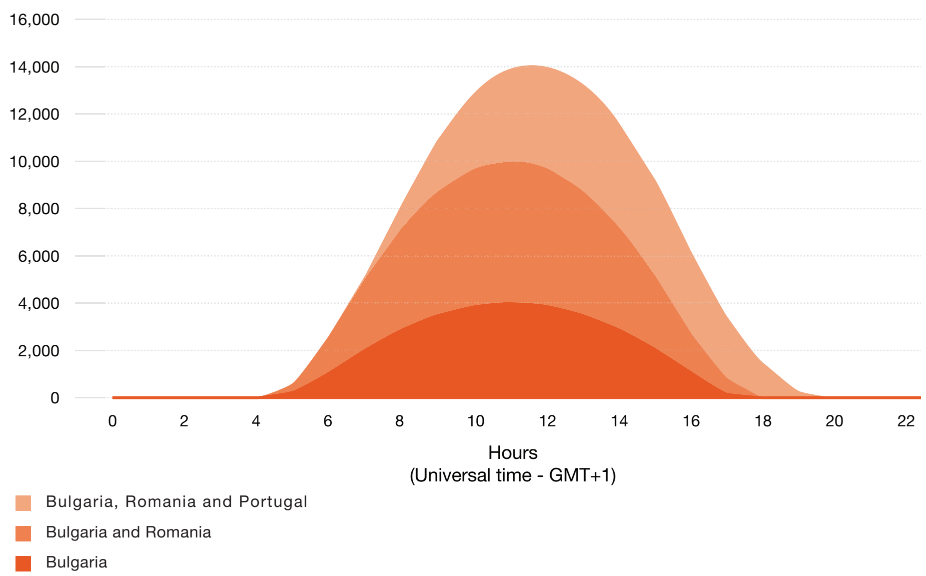
Electricity demand varies continuously. Because small imbalances would occur relatively quickly in intolerable frequency deviations, the electricity system has been designed in such a way that it can cope with relatively high variability, mainly by production following demand variability.

On a regional scale, hourly variability plays a role during region-wide power ramps (when demand increases or decreases), especially in the morning and evening (easy to forecast), but also during special events, such as a storm front (more or less predictable), or vanishing fog affecting a large area (currently difficult to predict).

Morning and evening ramps are mostly tackled in the day-ahead and long-term markets (because they are predictable). **PV ramps often occur as demand ramps in the same direction**, which is an advantage; but sometimes there is a time shift in both ramps. As a result, flexible plants need to compensate for this brief discrepancy in countries with high PV penetration. In winter, this can occur in the evening; in the summer, it typically happens in the morning.

Over the long term, this effect will be less pronounced on a European scale than on a regional one, thanks to the time-zone difference between the far east (Romania, Bulgaria) and the far west (Portugal) prolonging the overall EU PV generation. This is illustrated in Figure 12 for a typical summer day under the EPIA 2030 scenario. At the EU level, east-west distribution of PV systems enlarges the PV production timeframe during the day.

Figure 12 - 2030 EU East-West PV production on a typical summer day (MW)



source: EPIA,2012

2.2.2.d Forecasting PV production and visibility

As the contribution of PV to the electricity supply increases, predicting PV generation becomes more important. An accurate forecast enables reliability and reduces costs by allowing more efficient and secure management of electricity grids and solar energy trading.

The prediction of PV generation is carried out for different time horizons using different forecasting methods (as described in Annex D):

- 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

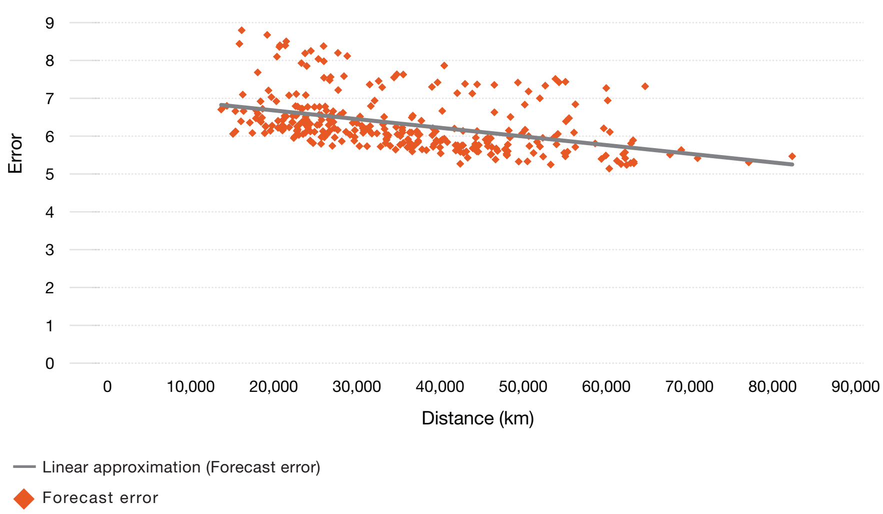
The accuracy of forecasting improves when wider geographic regions and larger amounts of PV systems are considered (Figure 13).

Integrated forecasts combine several methods and inputs to provide the most accurate forecast possible. **Today the best forecasting achieves errors (Root Mean Square Error, RMSE) of 8% to 11% for day-ahead predictions of single plants[7]. For larger portfolios and total regional production this number is much lower (4% to 5.5%)**.

Forecasting PV on a regional scale is relatively new (in Germany and Spain since 2010). Commercial PV forecasting on a single-plant scale is very new (only since the beginning of 2012). As a result, there is still a high potential for improvement. Increased accuracy is also expected to result from continuous improvement of weather predictions.

Forecasting a single plant or a portfolio of plants could help market valorisation of PV electricity, whether from day-ahead market bidding or intraday market bidding. Accurate forecasting of regional production could significantly increase the returns from spot market trading. Importantly, accurate forecasting will lead to lower system operation costs.

Figure 13 - Forecast errors example of the production of a PV portfolio (%)



source: EPIA, 2012

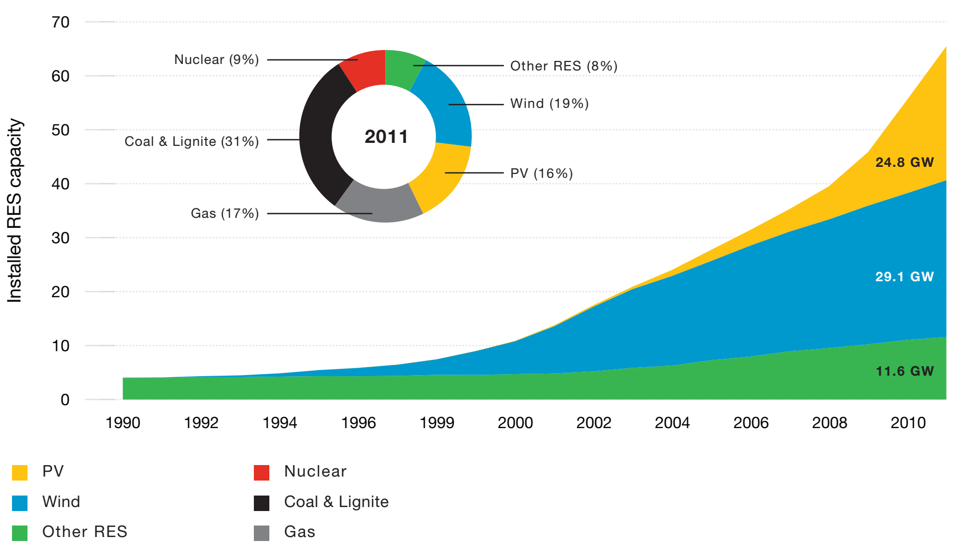
2.3. Security of supply – not at risk

2.3.1. What is security of supply?

Security of supply refers to the capability of the power system as a whole to provide electricity to end-users in all circumstances. From a broader and long-term view, security of supply comprises access to primary fuels, system adequacy, generation adequacy, network adequacy and finally market adequacy[8]. Simply focusing on the short-term security of supply and generation adequacy fails to take into consideration possible shortages and system faults that can occur no matter the type of generation. Instead, PV should be seen in light of how much generating capacity it can provide and when.

Already today in some countries the installed capacity of PV meets a significant share of the overall installed generation capacity. In Germany for instance, at the end of 2011, 24.8 GW of PV capacity coexisted with 29.1 GW of wind capacity – representing together more than 35% of the total installed generation capacity (Figure 14).

Figure 14 - Evolution of installed capacity and 2011 electricity mix in Germany (GW)



source: Based on Fraunhofer IWES and EPIA figures, 2012

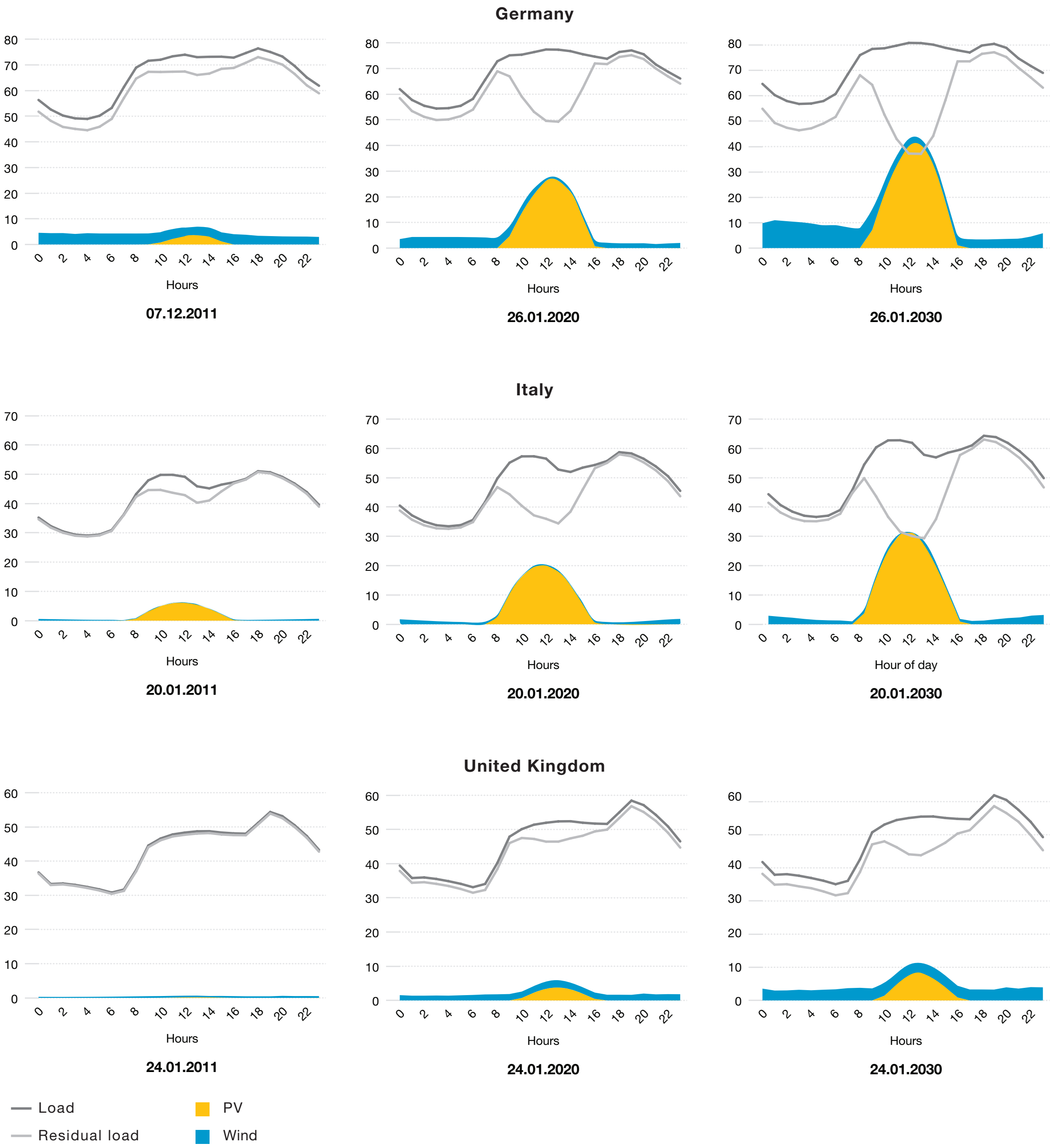
2.3.2. Securing generation adequacy

As previously described, PV and wind produce electricity when the sun and wind are available. Additional "back-up" sources (renewable, conventional and storage) may be needed to achieve generation adequacy and ensure the security of supply both in base-load and peak periods.

Peak residual load refers to the day of the year on which PV and wind generation requires the most "back-up" sources.

In Figure 15 the day of the year with the peak residual load is seen for three countries: Italy (with high electricity share from PV and lower share from wind), United Kingdom (with high share from wind and lower from PV) and Germany (with high electricity share both from PV and wind). In these three countries, that day occurs during winter.

Figure 15 - Peak residual load in Italy, Germany and United Kingdom for 2011, 2020 and 2030 (GW)



source: EPIA, 2012

Figure 15 reflects some elements that are important for the operation of the power system. First of all, it can be seen that at least by 2020 and to a greater extent by 2030 PV generation always contributes to the reduction of the high load at noon hours (including in the United Kingdom). Even during the winter, PV can meet a significant part of the midday peak demand in countries such as Germany and Italy.

Did you know?

On 9 February 2012, during a particularly cold European winter, France imported nearly 10 GW of electricity from Germany to meet demand from electric heaters. Nearly a third of this imported electricity came from PV.

However, PV does not contribute to the reduction of the evening peak that occurs in almost all countries around Europe. This does not represent an issue today given the conventional capacity available in the system. But with increasing penetration of PV, the power system will have to be secured at all times, even during the "worst day" scenario presented in Figure 15. In order to reduce the need for conventional power running on a standby mode, additional solutions will be required that compensate for the time when PV is not producing, or that shift part of the PV production from midday to the evening peak, or that shift demand. These could include short-term storage, DSM, and energy efficiency measures. Capacity credit and complementary contributions of PV and wind can play a significant role in achieving this.

2.3.2.a Capacity credit

Capacity credit (%) – also referred to as firm capacity (GW) – is an assessment of how much PV and wind can contribute to meeting peak consumption.

In most countries in Europe the peak load occurs in winter during evening hours (Figure 15).

In some particular cases such as Italy, the peak load occurs during summer at noon when PV generation is high. Simulation results from this study have shown that **in Italy PV can reduce the summer peak by about 5.8 GW, with an annual net reduction of almost 1.6 GW.**

2.3.2.b Thinking system-wide: PV and wind working together

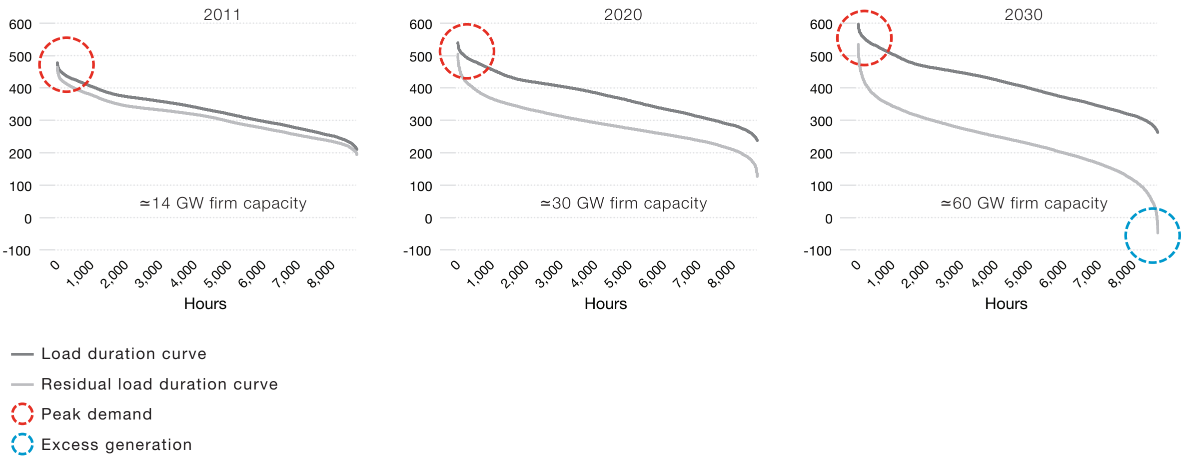
Capacity credit at EU level: PV and wind contributing to peak demand

Capacity credit can be increased by considering the combined capacity credit of PV and wind at the EU level, assuming stronger interconnections among countries and grid reinforcements.

Figure 16 shows the load duration curve in the European electricity system from 2011 to 2030 with an additional focus on the residual load duration curve (demand minus PV and wind production). **The combination of PV and wind together clearly reduces the demand to be met by other generators during most of the year at EU level**.

The few hours when the highest demand occurs (red circles in Figure 16) have an impact on the combined capacity credit of both technologies. It is assumed that targeted energy efficiency policies and demand side strategies (shifting back consumption from the night-time to daytime) could have a positive impact on capacity credit acting during a limited number of hours to reduce the peak load demand. During a limited number of hours a combination of large PV and wind production exceeds low demand (blue circle in Figure 16). This issue will be analysed later in this chapter.

Figure 16 - Annual residual load duration curve in the EU 27 – PV and wind capacity (GW)



source: EPIA, 2012

Storage can change the picture and increase substantially the capacity credit of PV and wind. Storage impact will be also dealt with later in this chapter.

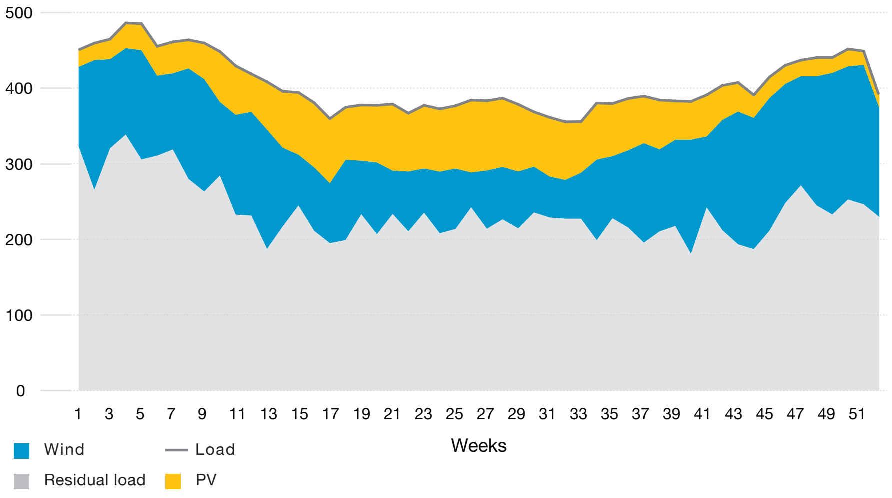
Load and residual load variation – PV and wind flattening the curve

On average, the number of sunny hours, and thus PV generation, shows hardly any variations from one day to the next. When looking at longer term averages a seasonal difference between the electricity generation in the summer and winter months can be observed.

Wind generation can vary significantly from one day or one week to the next. And just like PV, wind exhibits a strong seasonal variation. However, generation is higher in winter and lower in summer. **The seasonal variation of PV and wind is therefore perfectly complementary**. Both generation profiles add up to a rather consistent PV and wind generation profile.

Comparing the average weekly demand and supply curves (Figure 17) clearly shows that **supply variations from variable RES often match load variations**. The result is a rather flat residual load curve. This significantly decreases the need for generation adequacy, thereby reducing the average need for backup sources during the year.

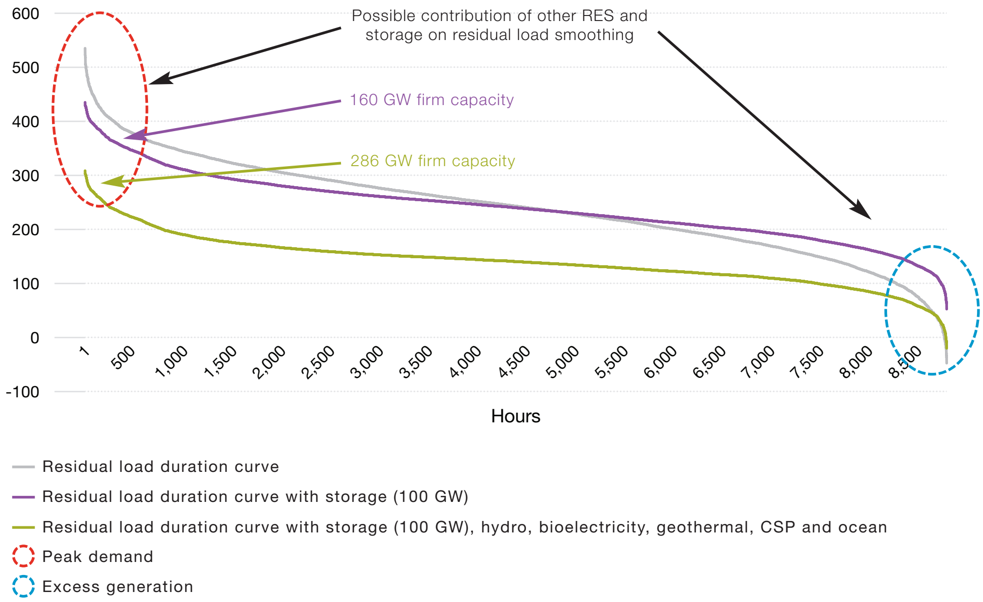
Figure 17 - Variations of weekly averages in the EU 27 -
Flat profile of PV and wind in Europe (GW)



source: EPIA, 2012

Other RES can also contribute significantly to reducing the peaks of the residual load. Figure 18 presents the results of a qualitative analysis of a possible impact of RES and storage capacity scenarios on the residual load: **A flexible "green" power system in conjunction with storage solutions could flatten the duration curve even more.**

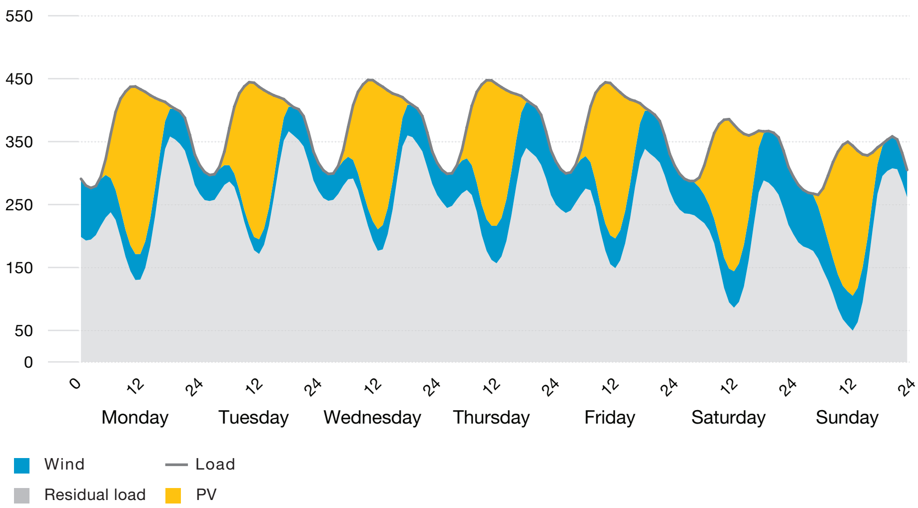
Figure 18 - Impact of other RES and storage on the residual load curve in 2030 (GW)



source: Based on EPIA, EWEA and EREC figures, 2012

This can be explained by looking at daily demand variations. For instance, the average daily load in Europe varies by about 100 GW between weekdays and Sundays. The residual load variation, on the other hand, could go up to 150 GW (Figure 19). This stresses the need to address this issue on a daily basis, using for instance storage or DSM.

Figure 19 - 2030 hourly variations over 1 week in August in the EU 27 (GW)



source: EPIA, 2012

2.3.3. Securing network adequacy

Networks must evolve according to generation capacity evolution, so as to facilitate electricity flows at the EU level. This is called network adequacy. The network infrastructure should ensure that every consumer has access to a secure electricity supply.

Congestion of important transmission lines may isolate parts of the grid, separating VRE power plants and flexible resources and reducing opportunities to share those flexible resources with another part of the grid[6]. Therefore to overcome these bottlenecks additional transfer capacity will be needed if even further advance operation techniques would first apply.

The addition of transfer capacity will require reducing long permitting procedures, overcoming public opposition to new power lines, and allocating costs more effectively. There is a clear need to streamline administrative procedures, while taking into account the possibility of increasing the capacity of the existing lines and of connecting large-scale storage.

Today, PV systems are mainly installed at distribution level and their production can usually be consumed within the same distribution area. As a result, there is currently very little impact at the transmission level, except from areas which are already coping with large-scale PV penetration.

In the future, decision makers will be faced with a number of deployment strategies in order to reach a 15% PV penetration scenario: PV generation could either be consumed within the distribution area or transferred to dense consumption areas. Whichever strategy prevails, large-scale PV deployment will imply a greater use of transmission lines. However, as shown in Figures 20, 21, 22 (corresponding data presented in Annex E), **if PV systems are installed close to consumption areas and where the grid is robust, the use of the transmission network will be limited; focusing on dense consumption areas would require only 10% more installed PV capacity compared to an EU irradiation-driven strategy, but would reduce by almost 75% the need to transfer the excess generation**. With the increasing competitiveness of PV in all major European electricity markets, shaping future grids around a single parameter – irradiation – would simply ignore this reality. Therefore, **any investment planning at the transmission level in line with the 2050 decarbonisation target should take into account the foreseen large-scale PV penetration and its capabilities to provide electricity close to where it is needed**.

Figure 20 - 2030 maximum excess PV capacity for an irradiation-driven deployment scenario (MW)

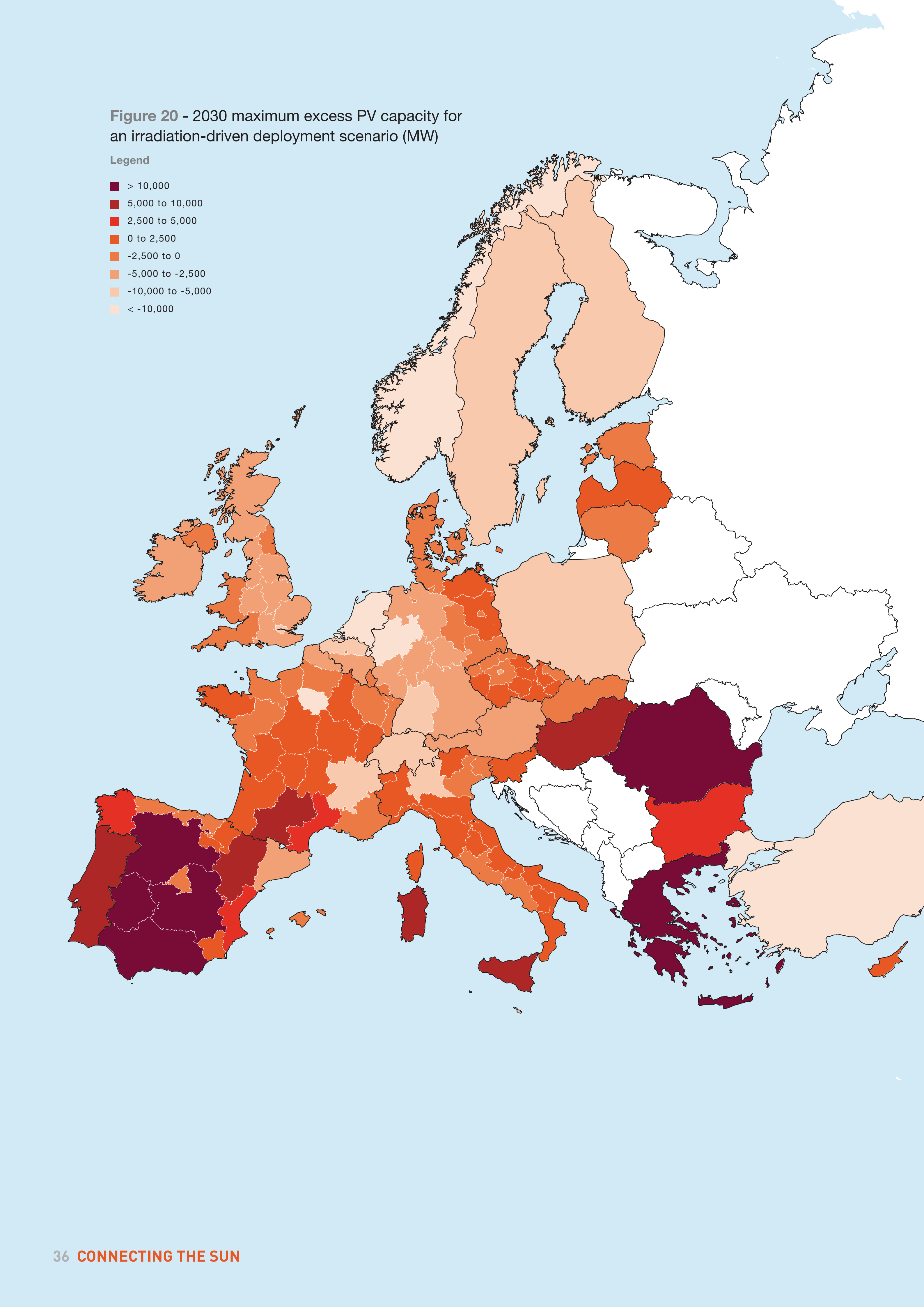


Figure 21 - 2030 maximum excess PV capacity for a consumption-driven deployment scenario (MW)

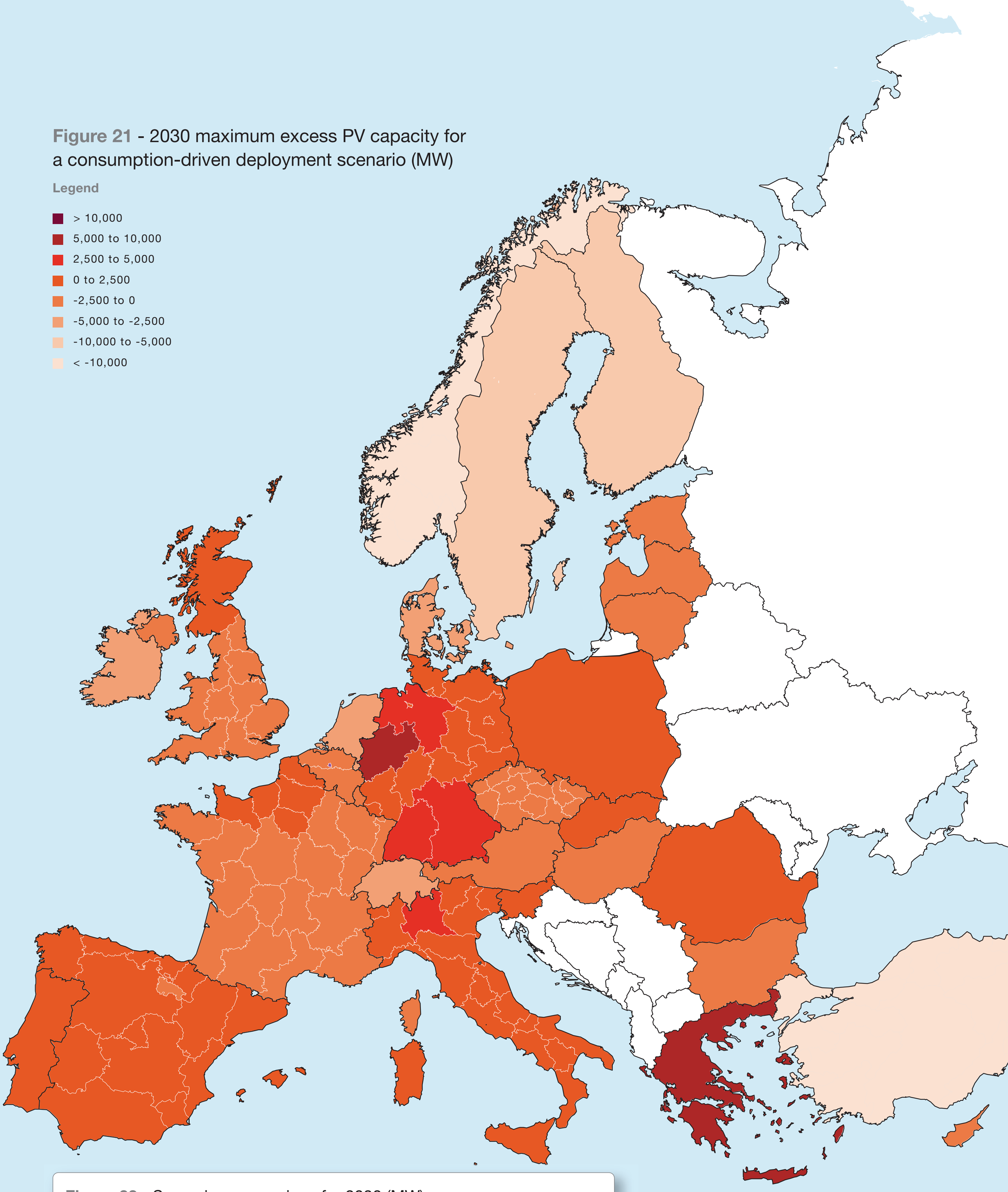
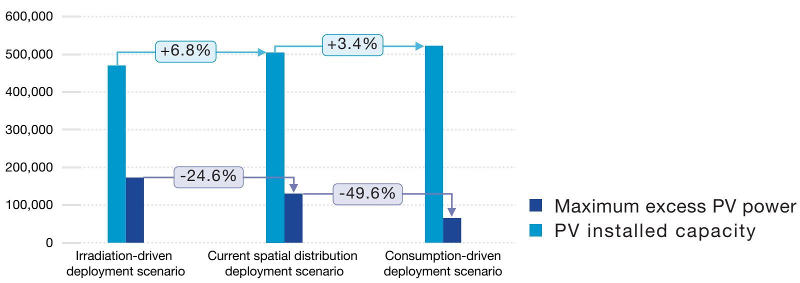


Figure 22 - Scenarios comparison for 2030 (MW)



source: EPIA,2012

2.4. Ensuring flexibility with more variable sources

2.4.1. What is flexibility?

Flexibility is the key requirement for planning and operating the power system with a large share of variable RES connected to it. It expresses the capability of the power system to maintain security of supply when rapid changes occur in production or/and demand.

In general, operational flexibility comprises[9]:

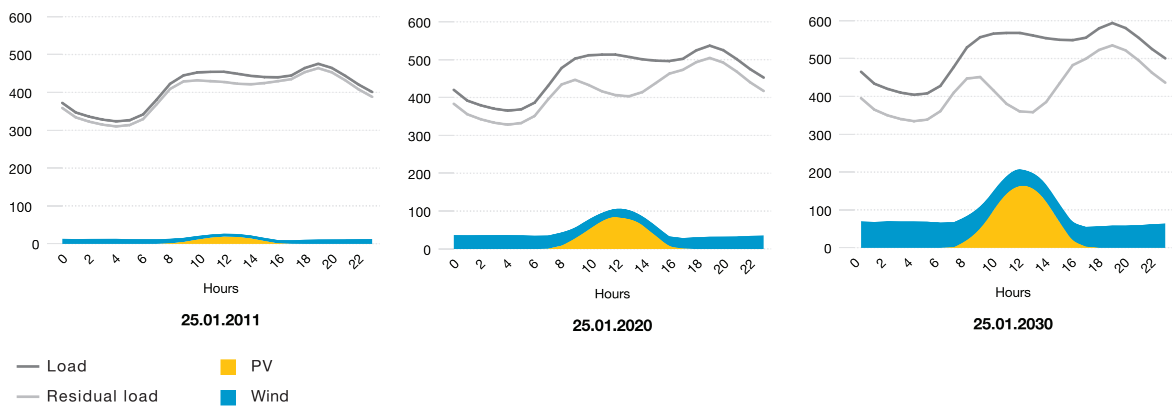
- Fast start-up and shutdown of the generator
- Fast load changes and ramps
- Start-up reliability and load predictability
- Frequency control and ancillary services

The International Energy Agency (IEA) has recently emphasised that **flexibility will be the key parameter of the future power system[6]. Flexibility can be provided by four types of assets: interconnections, storage, DSM and flexible generation**.

Only a proper mix of these assets will limit the costs of the transition. For example, if only flexible generation were implemented, high costs would incur for maintaining the full power fleet on-line while operating them during a limited time. On the other hand, there is a risk of under-investment in flexible generation due to market uncertainties for plant operators. This may lead to a situation in which generation adequacy is not sufficient to offset the combined effect of low PV and wind generation.

Figure 23 shows that European PV and wind generation match each other and, due to smoothing effects across wide areas, the maximum residual load can be reduced in comparison to the peak load of the system. Interconnections allow the sharing of flexibility to address the variability of single areas/countries. This can be understood by comparing Figure 23 with Figure 15, where the impact of PV and wind on the peak load is shown at the national level. Extending and strengthening the existing interconnection capacity between countries and regions will provide further flexibility to a certain extent. However, the investment in new infrastructure should be planned based on cost-benefit analysis in the particular region and in comparison with other flexible resources.

Figure 23 - Peak residual load in the EU 27 (GW)



source: EPIA, 2012

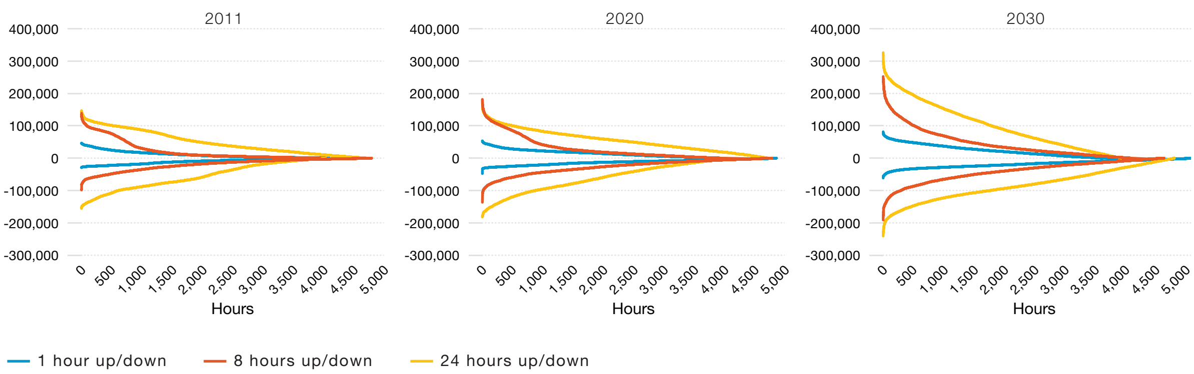
Additional flexibility resources can be obtained by:

- Better exploiting the potential of existing and proven storage capacities like pumped storage plants
- Focusing on the improvement of existing cost-efficient storage capacities (repowering) and on the development of new short- and long-term storage; heating storage could be a short-term solution while for the longer term Electrical Vehicles (EVs) should be introduced
- Tapping the demand-shifting potential in order to move potentially flexible demand in line with PV and wind generation
- Improving the forecasting of generation and demand

2.4.2. Ramping challenge due to VRE – a groundless argument

The generation adequacy faces an additional technical challenge: the need to follow residual load ramps. In order to evaluate how much up and down ramping will be required from other flexible sources, an analysis was carried out to identify the variability of the residual load. For this purpose the residual load difference within 1, 8 and 24 hours was analysed (Figure 24). The duration curves for EU 27 countries show how many hours of the year certain ramps are required to cover the residual load difference within the analysed time intervals.

Figure 24 - 2011, 2020 and 2030 ramping requirements in the EU 27 (MW)



source: EPIA, 2012

The 1 hour ramp curves show how much PV and wind affect the variability of the residual load and therefore how much flexibility will be required within an hour (vertical axis) and for how long (horizontal axis).

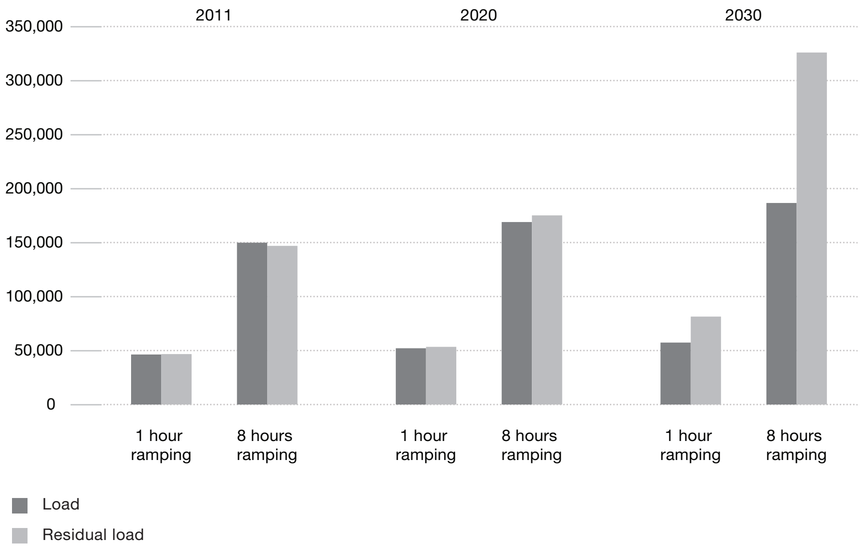
Table 1 - Maximum and average ramping (1 hour duration) in the 6 key countries and in the EU 27 until 2030 (MW)

	2011		2020		2030	
Country	**Maximum ramping**	**Average ramping**	**Maximum ramping**	**Average ramping**	**Maximum ramping**	**Average ramping**
Germany	10,300	5,000	14,500	7,000	23,200	9,000
Italy	7,200	4,000	12,400	5,000	18,500	8,000
France	8,800	4,000	10,000	5,000	17,400	8,000
Spain	6,100	3,000	9,000	5,000	14,500	7,000
United Kingdom	8,100	2,500	9,000	3,000	12,100	5,000
Belgium	1,500	500	2,100	900	4,700	2,000
EU 27*	46,800	21,000	53,000	25,000	81,400	41,000

source: EPIA, 2012
*: The maximum ramping for the EU 27 is not the sum of the maximum ramping of each individual Member State, as the demand profile is different from one country to another.

Table 1 shows the maximum and average ramping (1 hour) of all the key countries in 2011, 2020 and 2030. For example in Italy, a country with high share of PV and low share of wind, today the maximum need for flexibility is 7.2 GW, while in 2020 and 2030 the adequacy capacity needed will be around 12.4 GW and 18.5 GW respectively for at least 1 hour per year.

Figure 25 - Impact of PV and wind on the 1 hour and 8 hours ramping requirement in the EU 27 (MW)



source: EPIA, 2012

The ramping requirement increase will still be driven by the load until 2020 (Figure 25). During this time, PV and wind are not affecting the power system flexibility. Beyond 2020, additional flexibility will be needed.

While fast but rather small fluctuations can be easily balanced, the real challenge is posed by the steep and high ramps that in the worst-case scenario require additional flexible sources.

This in particular raises the question whether it is possible for the conventional power fleet to follow these high ramps, considering that a cold start of conventional power can require up to 16 hours. Table 2 shows representative conventional power plants start-up times and ramping.

Table 2 - Conventional plants start-up times and ramping

	Gas-Fired power plants (OCGT*/CCGT)	Steam power plants	Nuclear power plants	New coal power plants
Hot start (<8 h)	30-60 min (few minutes for OCGT)	60-480 min	120 min	150 min
Warm/Cold start (>8 h/>48 h)	60/200 min	>480 min	180/1,000 min	200/600 min
Ramping (MW/min)	5-30 MW/min (30 MW for OCGT in specific places)	3-5 MW/min	0-5 MW/min	3,5-12 MW/min
Flexibility (% capacity)/1 h	50% (100% for OCGT)	40%	16%-30%	50%

source: EPIA, based on Siemens and IEA figures, 2008-2011
***OCGT:** Open Cycle Gas Turbine

In fact **these ramps can be easily met and such variations can be easily followed by currently installed flexible sources until 2020**. Arguments that very steep ramps cannot be met are groundless. **To achieve VRE penetration foreseen in 2030, additional flexibility will be required** so as to reduce the periods during which part of the conventional power fleet will have to be operated in standby mode to respond quickly to any balancing needs. Additional flexibility will increasingly be provided by a combination of dispatchable RES (hydro, biomass, geothermal, etc.) as well as innovative storage options and DSM. Since PV and wind production can be easily forecast, **coordinated actions can be planned for these few hours**.

2.5. Avoiding excess generation

2.5.1. A known challenge

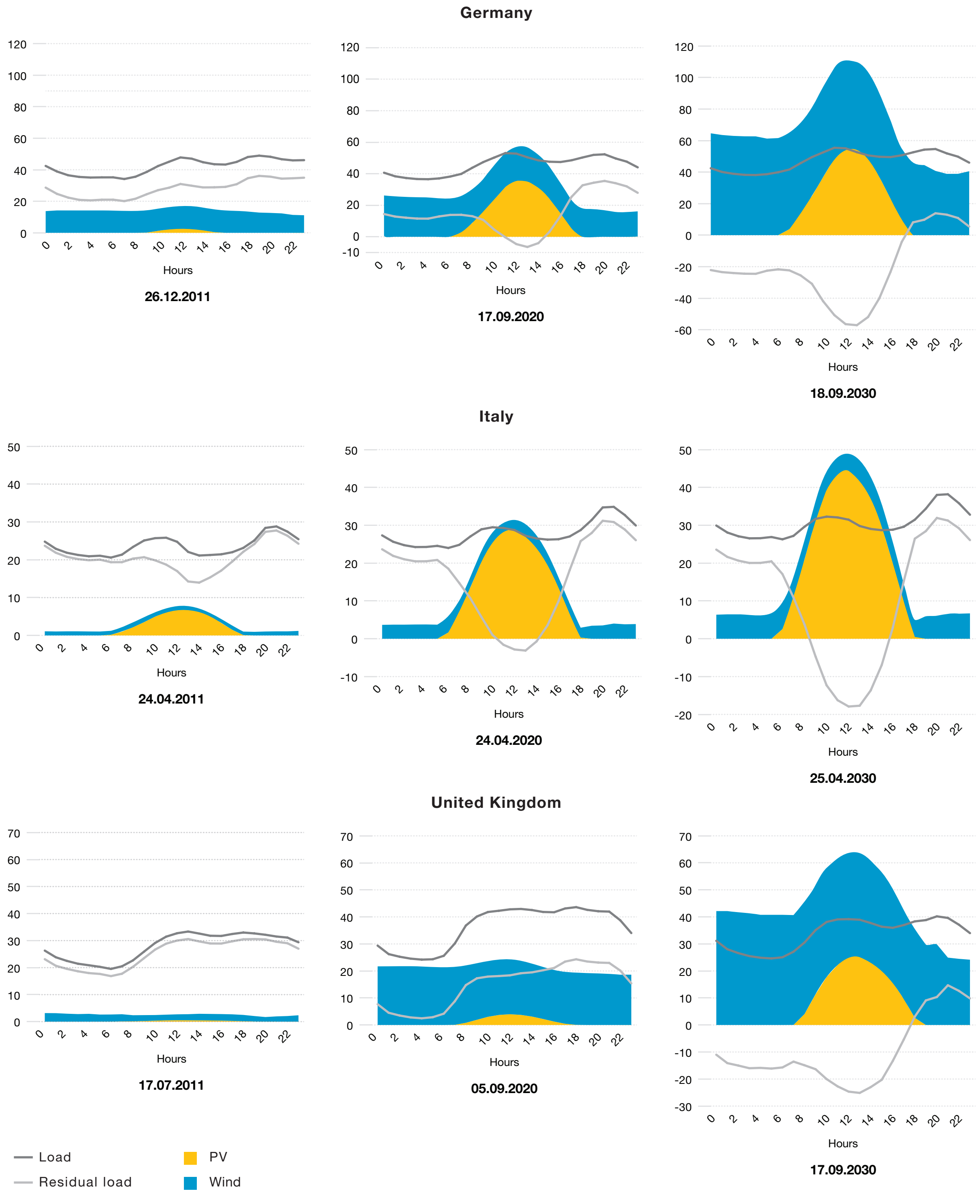
Possible excess of electricity generation needs to be considered when planning over the long term and assuming scenarios of high penetration of variable generation. Cases have been reported already in 2012 when at times of excess generation, electricity was sold at negative prices since demand at that moment was insufficient. The challenge arises at the times when PV and wind generation in Europe exceed the demand and export capacities. Then, when no storage capacities are available, generation has to be curtailed for security reasons. In these cases, electricity generated from climate-neutral sources would be lost.

For this study EPIA ran simulations to determine whether there would be excess generation from PV and wind during days with minimum load. Excess generation is considered from the point of view of the load on one side and PV and wind generation on the other. The assumptions are described in Annex C.1.

2.5.2. Risk of excess generation per country

Already by 2020 it can be expected that installed PV and wind capacities will be higher than the minimum load in some countries. The balancing simulation in 2030 shows that there is the possibility in extreme situations (when minimum load coincides with high PV and wind generation) to experience excess generation in some EU countries (Figure 26).

Figure 26 - Minimum load and high PV and wind production in Germany, Italy and United Kingdom (GW)



source: EPIA, 2012

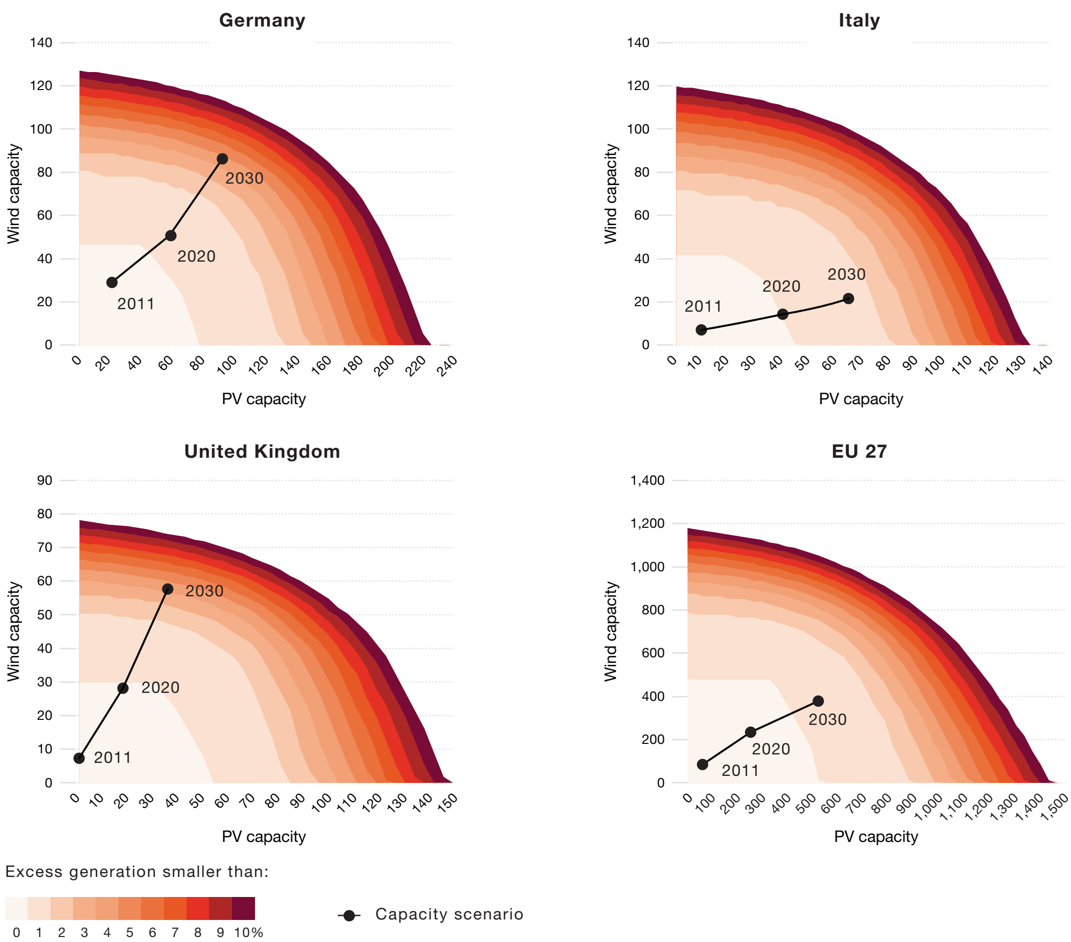
This stresses the challenge of excess generation in some countries (Germany and Italy) by 2020. In 2030 almost all the key countries are likely to see excess electricity generation at certain times during the year. In countries with a high share of PV, excess generation can take place at noon when there is high PV generation (Figure 26). Knowing that, **storage solutions could be applied that would shave the peak PV production and shift it to evening hours, or DSM solutions could be used to shift demand to noon, when the highest production occurs. A combination of both could be the optimal result**.

The time when there is excess generation is very small compared to the electricity generation throughout the whole day; over the course of a year it is even smaller.

Figure 27 presents a way to estimate the percentage of excess generation in Germany, Italy, United Kingdom (UK) and the EU 27 will experience when feeding more PV and wind power to the existing power system without any storage or without considering priority dispatch from other power plants. The estimate follows the capacity scenario and is based on the overall annual demand of each country.

On one hand the data show that certain solutions will be needed to cope with excess capacity. But on the other hand, in certain countries there is room for more installations of either PV or wind without exceeding the generation due to complementarities. For instance in Italy more wind can be installed without crossing the 2% excess-generation line (about 23 GW). With PV this point is reached earlier (about 10 GW) if no solutions are implemented. In the UK the opposite phenomenon is shown.

Figure 27 - Estimation of the percentage of excess generation based on PV and wind capacity scenario (GW)

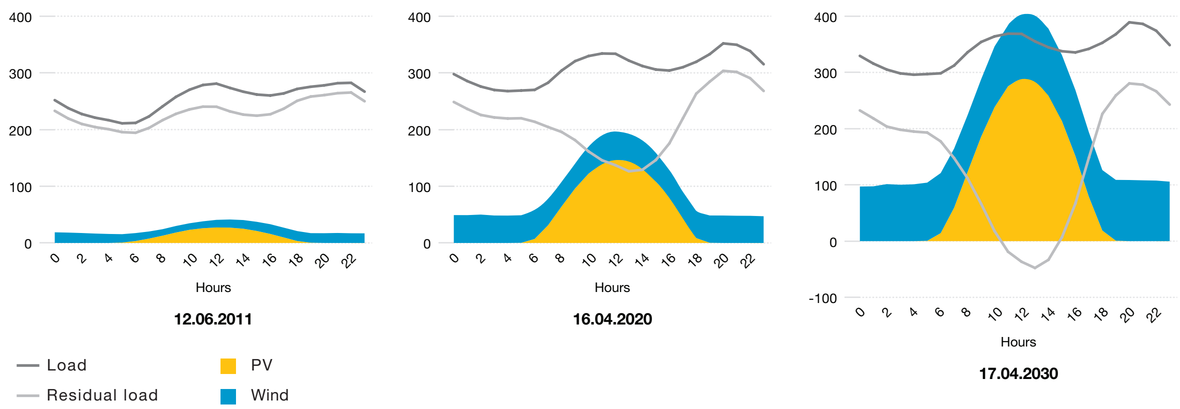


source: EPIA, 2012

2.5.3. Risk of excess generation at EU level

Obviously, excess generation per country would lead to several possible consequences of both a technical and market nature. But given that excess generation should be considered on a continent-wide scale, the netting effect of production and consumption can be increased (Figure 28). While some countries have a negative residual load already in 2020, this is not the case at the EU level, where the excess does not appear until 2030. In other words, **because excess PV and wind generation can be exported to neighbouring countries with the ability to absorb it, the challenge is not as acute at the EU level, assuming adequate interconnections.**

Figure 28 - Minimum load and high PV and wind production in the EU 27 (GW)



source: EPIA, 2012

In comparison with the 2030 situation, the current installed capacity of 135 GW of PV and wind does not appear close to producing excess generation at a European level. Considering that today the overall minimum load in the European system is about 200 GW and can even reach 280 GW during summer noon, when PV generation is high, even if all PV and wind plants were to generate at full power during these load minimums, the load would still be twice as high as the generation. Therefore **all PV and wind power generated in Europe could be fully consumed internally until 2020.**

However, a deeper analysis reveals that excess production might come sooner than expected:

- The current electricity grids in Europe still do not allow to net production and consumption flows through the whole continent; an excess of wind electricity in Denmark or PV electricity in Germany cannot result in emergency exports if the demand is not present
- PV and wind plants are not the only electricity generators to benefit from priority dispatch; other renewables and in some cases cogeneration units can inject their electricity with priority into the grid
- Part of the conventional park in Europe is considered as inflexible; some plants cannot reduce their output, mainly for financial reasons but also for the technical impact of such reductions; this means they have to feed in, leading to excess generation

These elements show that, **while VRE could easily be integrated until 2020, Europe must act now in order to prepare its electricity system to cope with large shares of RES.**

2.6. Shifting or storing: PV matching consumption

2.6.1. Demand Side Management

DSM is a resource that by definition can provide flexibility to the demand side (upwards or downwards) and has been mentioned extensively throughout this chapter as a solution for promoting large VRE integration by reducing possible unwanted effects such as excess generation and increased standby capacity due to ramps. DSM is a significant tool for network operators, who must plan and monitor their activities in order to produce load curves that can be met more efficiently by the generation adequacy. DSM is not a new idea. One method that has been used for years in many countries is the night-and-day electricity tariffs, which create an incentive to use electricity at night when there is an abundance of conventional generation. In other words, DSM has long been used by large industry, but with the aim of reducing the day peak rather than balancing the system – as it could be used today.

In general there are two components of DSM:

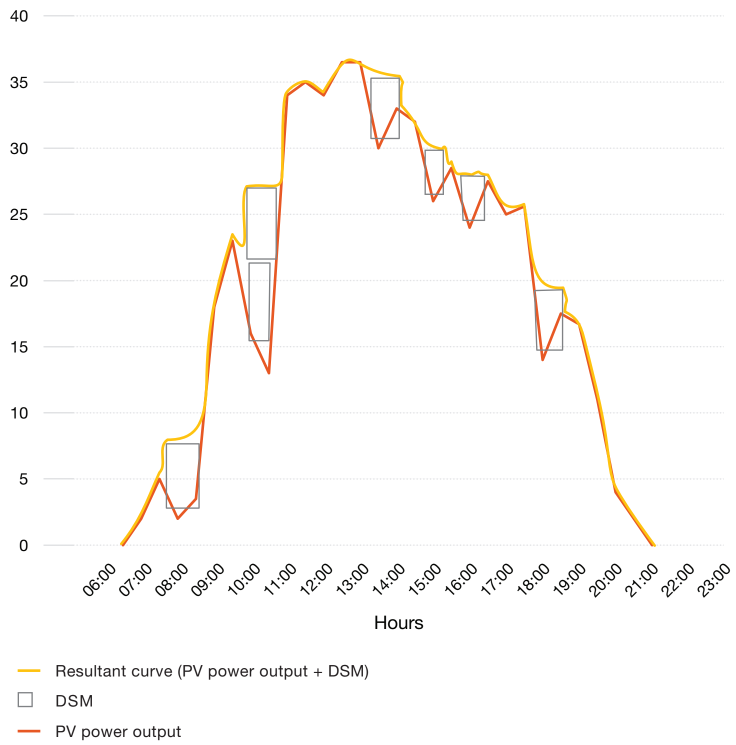
- Energy efficiency, in which utilities contract with customers to reduce electricity consumption for a specific amount and specific time (load curtailment)
- Demand response, which requires a change in on-site demand and is associated mostly with balancing needs (load signal) or electricity price signals

Both components can be an instant flexible resource by responding to a signal. Consumers then switch on or off, shifting the electricity demand from times of high electricity peaks to times of low electricity demand. With the introduction of more variable RES into the system this technique is of particular importance because it **provides the ability to shift the demand at times when VRE produce most**. For PV technology that would mean shifting the flexible part of the evening peak to noon, when there is the highest production. For this reason DSM is considered as a type of storage (load-storage or "negawatt" producer). This can be seen also in Figure 29, which shows the typical production of a small PV system and the potential smoothing effect of DSM use. In the right figure it is evident that the modulation of consumer demand helps fill the voids and smooth the curve.

Did you know?

Today's best examples of DSM are found in the industrial and commercial segment, where normally there is an available communication infrastructure. Therefore using cheap electricity at nighttime is currently easier and more cost-efficient compared to DSM techniques at the household level.

Figure 29 - Use of DSM to smoothen the PV power output (kW)



source: Based on Energy Pool and EPIA figures, 2012

There are various examples of successful implementation of DSM today (e.g. Energy Pool in France). In Germany the DSM potential in the industry and manufacturing sector has been estimated at around 9 GW (Entelios). Of course to successfully manage a significant amount of load, aggregation techniques should be applied. **Aggregators can play an important role technically and also in energy exchange and market-related issues since they offer an extra flexibility from the demand side to meet production in a cost-efficient way**.

Until now consumers participating in DSM have been large electricity consumers (industrial or commercial). This is because:

- The communication infrastructure was in most cases already in place, so there was no additional cost involved
- Large consumers pay separately for peak power and electricity consumed. Thus they always seek to minimise peak power demand to reduce costs

By aiming to decrease balancing needs in the future with high VRE deployment, large electricity consumers can more easily provide grid services through demand response. At the household level, DSM will require advanced monitoring and communication infrastructure; smart meters or internet-based demand response programmes (as has been seen in the U.S.) **can help to transfer price or energy information that can trigger the DSM**. Aggregators can play a role also at this level; however, industrial consumers are more likely to offer the service directly.

2.6.2. Energy efficiency in the electricity sector

Energy efficiency in the electricity sector comprises a range of technologies and techniques that have as an ultimate goal energy savings along the electricity value chain.

In **power generation** energy efficiency refers to measures that aim to improve the efficiency of existing power plants and to use all available efficient technologies to build new and cost-beneficial capacities.

On the **grid side** energy efficiency could refer to High Voltage Direct Current (HVDC) lines that reduce the transport losses and increase the capacity of existing power corridors. Furthermore, Dynamic Thermal Rating (DTR) can be part of the energy efficiency techniques, since it allows integrating more VRE (mostly wind) without compromising the reliability of the system.

On the **consumer side**, energy-efficient synergies (for instance PV and heat pump), smart metering to coordinate and display better the electricity used and other modern passive techniques can facilitate electricity savings.

Did you know?

DTR or Dynamic Line Rating (DLR) is a technique in which the temperature of the line is measured in real time and the actual capacity of the line is estimated. DTR of power transmission lines can usually provide a significant increase of transmission capacity (up to 50%) compared to static rating.

Using energy efficiency to improve system adequacy globally

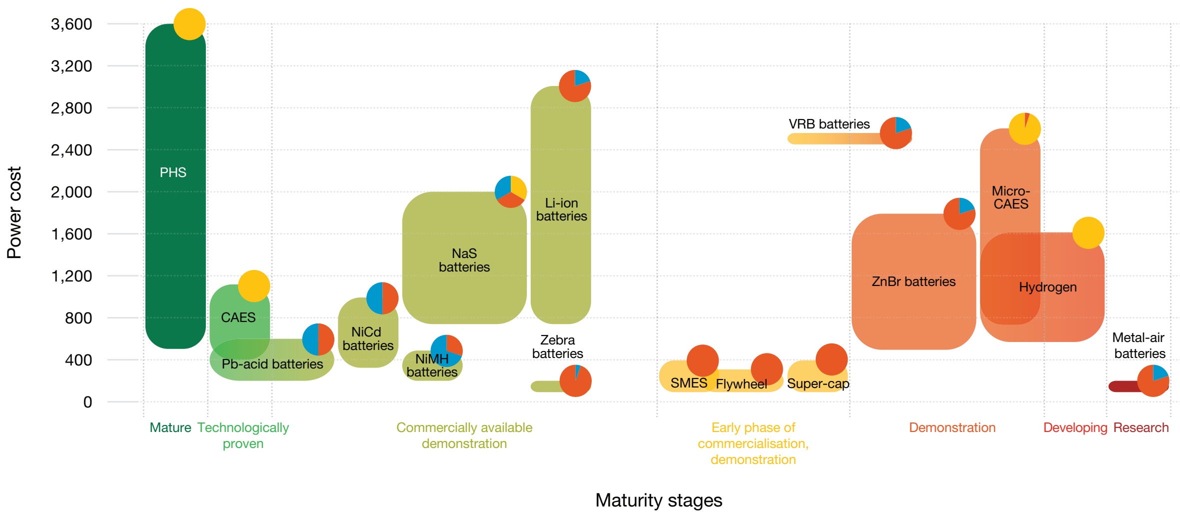
Comparing the residual load duration curve to the demand curve shows how much the combination of PV and wind can help decrease the residual electricity demand. But two points of interest remain to be studied more in depth: the hours of low demand and the hours of high demand. In both cases, the combination of PV and wind tend to increase or decrease the gap with residual demand and initial demand as seen in previous parts of this chapter. During a few dozen hours a year, the demand should be reduced in order to decrease dependence on standby plants. However, on some days demand is too small, even at the continental level, to absorb all the available electricity.

In both cases, energy efficiency measures (reducing peak demand) and DSM (reducing excess generation) could decrease overall system costs.

2.6.3. Energy storage

Within this study a set of simulations was performed to assess specifically the contribution of energy storage to a flexible future power system with high VRE penetration scenario. Figure 30 shows only part of the available storage technologies. The potential for much-needed improvement in the energy storage sector is great. **There is no single energy storage option to cover all requirements in all European regions. Applications, technological development and market evolution will define the share of centralised and decentralised storage solutions in the power system.**

Figure 30 - Available energy storage technologies (€/kW)



Storage technology application:

- End-user
- Transport and distribution
- Power generation

PHS: Pumped Hydroelectric Storage
CAES: Compressed Air Energy Storage
SMES: Superconducting Magnetic Energy Storage
VRB: Vanadium Redox Batteries

source: EPIA, based on JRC analysis, 2011

2.6.3.a A wide range of services

Energy storage can play many roles in the system, including[10,11]:

- As **energy management application:**
    - **Storage can act as a Distributed Energy Resource (DER)** by providing electricity and competing with other technologies based on cost and depending on application
    - **Energy shifting of VRE** increases the capacity factor of the system and the penetration of PV and wind by displacing excess production when there is high demand and low production, especially during peak consumption (e.g. evening hour-peak shaving)
    - **Storage can smooth load curves and enable the customer to shift its peak loads**. This is also known as arbitrage or load levelling and generally implies that the storage unit is being charged at off-peak times when the prices are low and discharged at peak times when prices are higher. In this case also the customer becomes more predictable for the grid operator who anticipates smoother load curves with no peaks and ramps ("ideal customer"). Both the utility and the customer could benefit from this service

Storage solutions with relatively high discharge duration and high capacity are best suited to these applications, e.g. pump hydro, Compressed Air Energy Storage (CAES).

- As **power application:**
  - **Storage can improve power quality**. Energy storage can provide ride-through capability ensuring frequency support until adequacy generation can be brought up to capacity. Storage can also provide black-start capability
  - **In cases of grid disturbances and faults storage can support the grid due to its fast response times and high flexibility**. In several critical grid situations those services in particular from pumped storage plants prevent black-outs and costly equipment damage; therefore such short storage applications can have a very rapid payback time

Short-term storages with fast discharge times at maximum power are needed for use as power applications, e.g. batteries, Vehicle to Grid (V2G) technologies, super-capacitors.

It is clear that **energy storage can enable a more efficient and flexible operation of the grid**. Today, cost is the most deterrent factor for large storage deployment. However, **if storage applications are installed to provide a combination of services then the solution becomes more cost beneficial**.

2.6.3.b Pumped hydro storage

Pumped hydro has proven to be one of the most readily available technologies for large-scale deployment. This is mainly due to its low price, which typically varies between 0.10 and 0.25 €/kWh (current average price of electricity from a pumped hydro plant, depending on the site). However, hydropower plants also become attractive because they can provide a number of services such as balancing reserve, voltage support and black-start capability.

The existing (51 GW) and future pumped hydro capacity in Europe can contribute significantly to the balancing needs and the total flexibility of the European system. Therefore it is needed to overcome existing hindrances (e.g. double grid fees and absence of a clear regulatory framework) to fully exploit the benefits of this technology.

2.6.3.c PV and daily storage

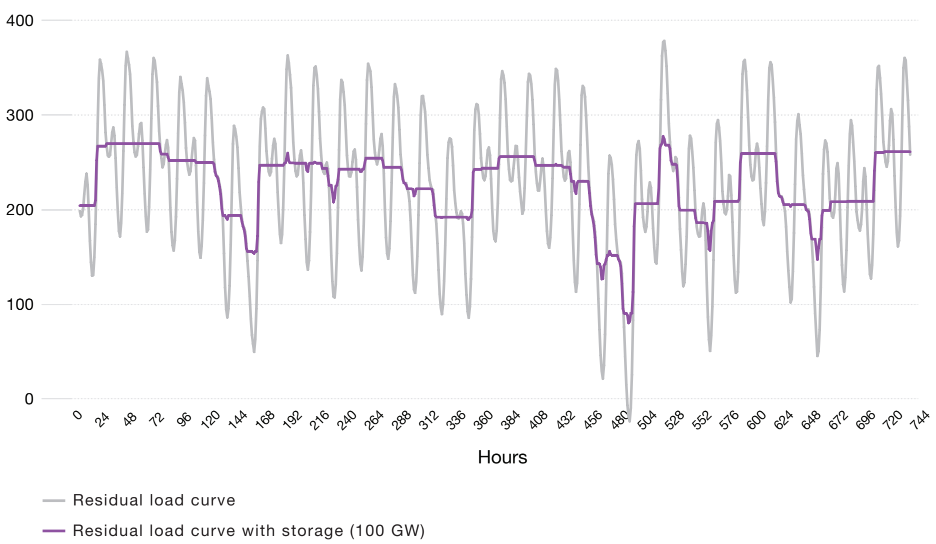
Daily storage is well-suited for PV peak generation. This is because it is guaranteed that PV generation (in a large region) is available every day with a perfectly predictable peak that always occurs around midday. As the peak demand in Europe occurs in the evening hours the time shift between peak PV generation and the peak demand never exceeds eight hours.

Did you know?

The term daily (mid-term) storage refers to the time in which storage can be charged or discharged at maximum power. Daily storage runs one storage cycle a day and has a capacity of roughly 8-12 full load hours, which is the typical capacity-power combination of a pumped storage plant.

Figure 31 presents simulation results for the 2030 Accelerated scenario that reflect this PV-storage compatibility for a summer month. A typical storage capacity of 100 GW with average storage use around 45% in spring and summer and 40% in autumn and winter time has been assumed to run the simulation. The key message here is that **daily storage complements PV, especially in summer, significantly flattening the residual load** (after storage). The same effect can also be seen on a winter day. However, the flattening of the load curve is less, due to larger variations of the load and less PV production.

Figure 31 - Impact of storage in August – Flattening the residual load curve (GW)



source: EPIA, 2012

Storage can flatten the residual load curve by significantly reducing the peak demand and avoiding excess generation (Figure 32). The former effect has a positive impact on the reduction of flexible standby capacity; the latter is a significant solution to excess generation (which wastes green energy) at the EU level that might be seen on some days in 2030.

Daily storage is already available today in the form of pumped storage plants and there is further potential for new capacity in Europe. This does not yet take into account Norwegian storage capacity that might be connected to the central European power system via an offshore grid. In total, existing, planned, licensed and Norwegian capacity can add up to about 80 GW[12]. When combined with DSM techniques, this could total 100 GW, the assumption used in this analysis.

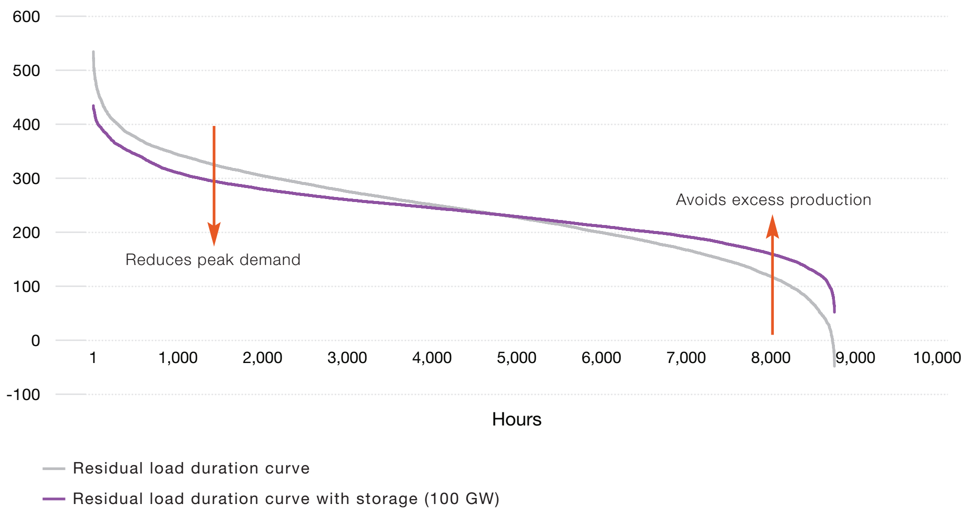
Further capacity might be built up by installing CAES storage capacities. Also batteries that run about two cycles a day, and therefore may shift the PV peak to demand peaks, might be used in the short or mid term, since their costs are decreasing. For these cost reasons the daily profile pattern of PV is a beneficial match. Finally, EVs can play a role here by being recharged during noon, for example at a company's charging point.

In conclusion the assumption used in this analysis – that storage and DSM techniques can offset 100 GW of peak PV production – is a realistic one even without taking into account possible deployment of decentralised storage. An optimisation analysis shows that beyond 150 GW there is no added value to increased daily storage capacity.

Weekly and seasonal storage capacities

It is often stated that there are enormous demands for seasonal storage capacities. However, there is an additional limited need for long-term storage capacities that balance the weekly variations. When intraday-spikes are removed with daily storage, flexible generation will be able to follow weekly load variations. PV and wind production are perfectly complementary, adding up to a rather flat monthly generation profile.

Figure 32 - Impact of storage on the residual load duration curve in 2030 (GW)



source: EPIA, 2012

2.6.4 PV systems providing frequency support

2.6.4.a Inertia

Inertia is an inherent characteristic of an electricity system based on rotating generators. System inertia is often considered as a vital system parameter upon which the system operation is based. It determines the immediate frequency response in case of power imbalances. The lower this system inertia, the more rapid the grid frequency reacts on abrupt changes in generation and load patterns.

PV systems and wind turbines are generally equipped with inverters which electrically decouple the generator from the grid. Therefore no inertial response is delivered during a frequency event.

When frequency changes due to an imbalance, inertia will initially dampen the effect. This phase is called inertial response. In a second phase, frequency is first stabilised and then restored to the nominal frequency by respectively the primary and secondary control. Additional measures, like automatic load shedding, can be taken in case of severe frequency deviations.

Both the inertial response as the primary and secondary control are highly influenced by the integration of RES. The effect of the penetration of RES will be most noticeable during low load situations, when the use of RES will require the conventional power fleet to be operated in standby mode, and consequently lower the overall grid inertia.

More research is needed on systems with low inertia and the impact of high penetration of PV, but in a future with a large-scale PV penetration, PV generators will have to participate in the frequency control. This could take the form of providing primary reserve or virtual inertia in combination with storage or other smart equipment (heat pumps, for example). Other concepts like load frequency support are also in the research phase.

It is clear that **when the power system has a very limited inertia, the whole frequency control methodology needs to be redefined. It will in this case be of crucial importance to take into account the inherent characteristics of each technology in order to define a cost-optimal approach**.

2.6.4.b Focus: 50.2 Hz issue

TSOs used to consider distributed generation only as negative load and therefore not relevant for electricity system operation. They required every installation to switch off automatically and instantly as soon as the frequency exceeded a defined range (depending on the country). These obligations are not a consequence of technical limits but are due to grid connection rules set by TSO/DSOs.

During the major system disturbance in Europe on 4 November 2006 (Figure 33), decentralised generation (mainly wind turbines) massively switched off after the disturbance happened (as they were required to do). This sudden loss of generation severely aggravated the situation and almost resulted in a major system blackout across Europe.

If the same extreme event were to occur at midday during the summer, more than 20 GW of PV systems would instantaneously disconnect from the grid at the EU level. Such a massive disconnection of PV systems would accelerate the possible cascading breakdown process.

But with a proper definition of the disconnection settings, **PV can easily support TSOs in the case of an extreme over-frequency event**. National grid codes have been revised in some of the key countries (Germany, Italy, Belgium and Spain) to integrate new frequency requirements (See Chapter 3). For the existing PV installed capacity, retrofit programmes are under analysis or already under way in countries like Germany and Italy.

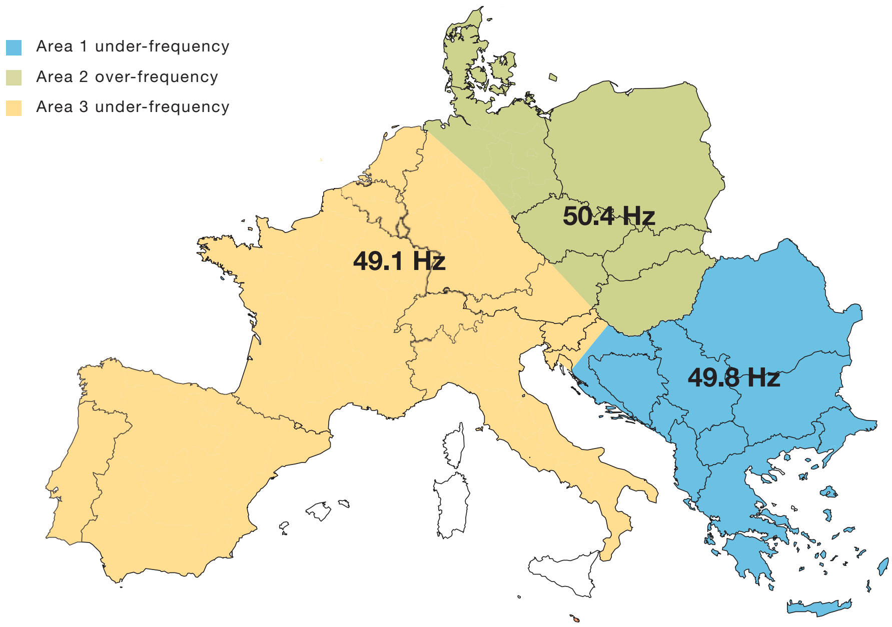
The so-called "50.2 Hz" issue has shown that **a proper collaboration among the PV industry, DSOs and TSOs is necessary to address the challenges of the future energy system**.

4 November 2006

The switching off of a transmission line in Germany caused an unexpected de-synchronisation event. The European transmission grid split into three independent parts for a period of two hours with too high or too low frequency.

The impact of this disconnection on the security of the network had not been properly assessed. 15 million households were left without power after a cascading breakdown.

Figure 33 - De-synchronisation in Europe (04.11.2006)



source: EPIA, based on UCTE analysis

2.7. Conclusions

The 2020 and 2030 scenarios described in Chapter 1 show that the European grid could have to host up to 45% (15% of PV, 30% of wind) and even 55% (25% of PV, 30% of wind) of variable electricity sources in 2030.

Based on these scenarios, the results from EPIA's analysis show that:

- **Large-scale PV integration in the European power system (8% by 2020 and 15% by 2030) is technically feasible with a high level of security of supply**, even under the most extreme weather and load conditions. With the right measures in place, system reliability can be ensured
- **PV generation is not intermittent but variable**. The belief that this variability implies a high level of unpredictability is misleading. Several efficient forecasting tools already exist; variability can be much more easily forecast when considering larger balancing areas. In fact a main advantage of PV is that **within a larger area it is guaranteed that PV electricity will be available and the profile and peak are perfectly predictable**
- **Flexibility is the key operational concept that has to be introduced to operation and planning schemes for the power system**. This flexibility can be provided by other RES and also flexible conventional sources
- The current electricity grids in Europe do not allow to net production and consumption flows through the whole continent. **Larger balancing areas and further interconnection will improve the power flow among the EU countries**, thus avoiding incidents of excess generation in extreme occasions and increasing the system's operation security
- **System-wide complementary approaches between PV and other RES** (especially wind) **will play a significant role in the reduction of the residual load**, but also in flattening the demand curve – facilitating the operation and planning of the power system. The strong seasonal complementarity reduces the need for costly long-term storage solutions
- Ramping needs can be technically met by existing flexible sources until 2020, making the ramping challenge a groundless argument. Beyond that additional flexibility will be needed. **Energy efficiency solutions can help flatten the demand throughout the year**
- **Cost-efficient daily storage**, which is already available at relatively large scale, **is perfectly well-suited to be combined with PV generation, as are DSM measures**. This is because it is guaranteed that PV generation is there every day and the pattern of PV production during the day can be predicted excellently. **Energy storage will increase the security of electricity supply, contribute to the avoidance of excess generation problems, reduce costly standby requirements and provide further ancillary services to the grid** (e.g. black-start). All storage options have to be considered depending on the application. Findings show that daily storage and DSM techniques can offset about 100 GW of peak PV production, without taking into account decentralised storage deployment. **While a beneficial level of daily storage and DSM can probably be set at 150 GW, no real added value of daily storage is brought to the system beyond that volume**
- **DSM of mainly large electricity consumers facilitates further VRE integration**. The need for DSM of smaller/household loads must be further assessed based on cost-benefit analysis. Most DSM flexibilities are restricted to shifts of a few hours and as such in the range of the time shift between noon peak PV production and evening demand peaks
- **PV system inverters can easily provide frequency support** if disconnection or other response settings are properly designed. In many cases a simple software update is sufficient

3

PV AND THE FUTURE OF THE DISTRIBUTION NETWORK

3.1. Introduction

Until now, the main role of the distribution grids has been to ensure the electricity supply to every final consumer. Distribution grids are the physical continuity of the transmission network and bridge the electrical connection to the users on lower voltage levels (households, SMEs and small industrial sites). The frequency as explained in Chapter 2 is the responsibility of the TSOs, but the DSOs must manage the second important aspect of power quality: the voltage level.

Consumer electrical appliances are able to work only within certain margins for frequency and voltage. Therefore, system operators have to ensure that every consumer has access to secure and quality electricity to avoid the degradation of these appliances.

Historically electricity was generated centrally in large power plants, with distribution grids designed to transport power in a unidirectional flow from the higher voltage levels to the end user on lower voltage levels. Today, more and more decentralised generation is connected to the distribution grid, as PV and wind behave more flexibly.

In this transformation process several questions arise: **Are there any limits to RES integration at distribution grid level? What will be the future role of the distribution grid and of the DSO in the power system? What technical and non-technical challenges will the future bring for distribution grid management?**

This chapter explores the technical feasibility of integrating high amounts of variable renewable electricity at the distribution level while helping to identify cost-optimal solutions.

3.1.1. Why will current distribution grid design have to evolve?

Electricity flows through the transmission grid, via transformers to the distribution grid and finally to the connection point of the consumer (LV and MV). The direction of the electricity flow is straight, from producer to consumer (Figure 34).

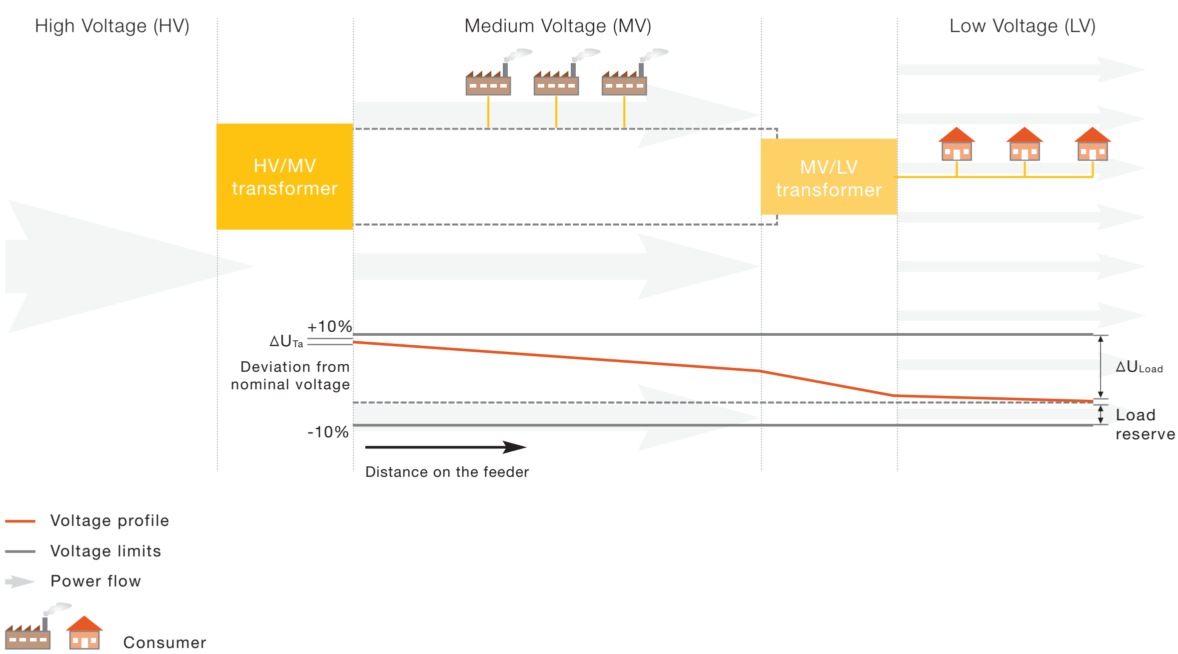
As a consequence line voltage always decreases relative to the distance (feeder length) and the level of consumption (electricity consumed on the same feeder - red line in Figure 34).

DSOs plan and manage the network in order to keep the voltage within certain margins for any connected consumer. This is necessary to ensure high power quality for safe operation of the end-users' applications. Power quality is described in international norms, used in national grid codes and technical guidelines, such as standard DIN EN 50160, which limits the voltage drop in low voltage grid to ±10%. The limits are represented by grey lines in Figure 34.

Transformers and lines are designed taking into account the most distant consumption point from the transformer. Usually transformers allow so-called tapping to set its voltage level (UTa). This allows controlling the voltage along the line in a certain bandwidth and ensures that the voltage of the final consumer is above the lower limit. Furthermore load reserve is usually kept for further consumption increase.

The arrival of distributed generation, such as PV, in the distribution grid has changed that. Electricity now flows in two directions: from the transformer to the consumer, and vice-versa.

Figure 34 - Voltage profile on an exemplary feeder without distributed generation



source: EPIA, based on AIT and E.ON Bavaria analysis, 2011

3.1.2. Rebalancing the roles: DSOs managing (distributed) generation

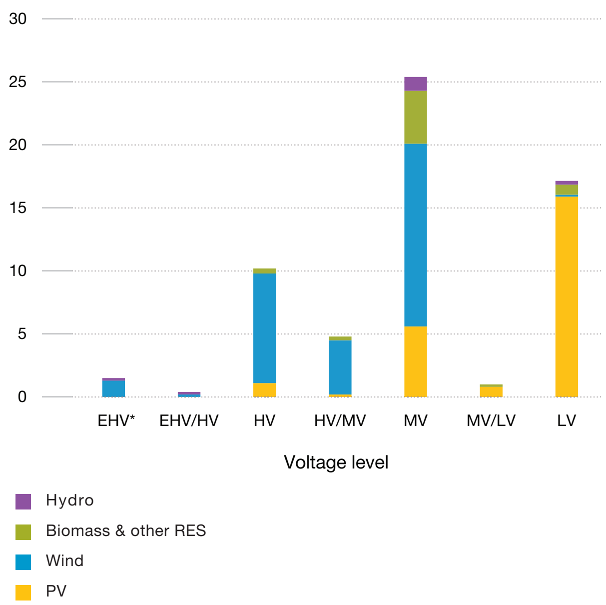
The transmission grid used to host almost all production capacity, but the arrival of distributed generation has changed the situation completely. Figure 35 shows the example of Germany, where there are generation capacities of PV, wind and biomass connected to the distribution grid. PV is representing the largest share on the low voltage network.

In Germany close to 70% of all PV installations are connected to the LV grid, usually with plants smaller than 100 kW in capacity. Another 25% of all PV plants are connected to the MV grid. These MV systems are normally higher than 100 kW. Large amounts of wind capacity are also installed on the MV.

Along with these high RES generation capacities on low and medium voltage levels come new challenges in the management of distribution grids as they maintain their high level of reliability at acceptable costs.

The main technical constraints distribution grids face these days are explored here, together with solutions that can be envisaged to achieve cost-efficient large-scale PV integration. This work is based on a series of interviews with DSOs. This chapter will also elaborate on best practices that have been identified together with network operators.

Figure 35 - 2012 installed RES capacity in Germany by voltage level (GW)



source: EPIA based on DGS figures, 2012
***EHV:** Extra-High Voltage

3.2. Challenges to integrating high shares of PV in the distribution grids

On a distribution line, when the power consumed is lower than the power produced, a reverse flow occurs. The electricity flows from the distributed generation to other consumers or to the higher voltage (Figure 36). As the distribution grid has not been built to host distributed generation, reverse power flows introduce some issues that must be tackled. The reverse flows may create grid bottlenecks that lead to:

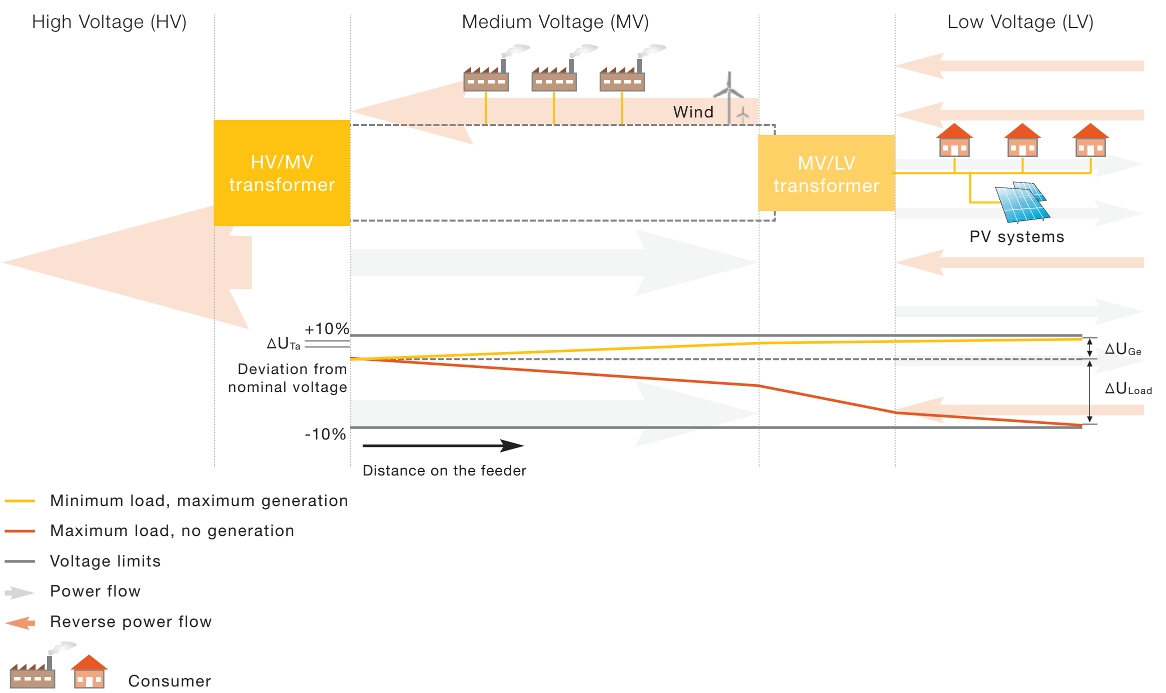
- First, voltage problems (voltage rise and possible excess of the upper voltage limit)
- Second, equipment overload (lines of transformers)

3.2.1. Voltage rise

Voltage rise represents one of the main impacts of distributed generation. In the case of weak or/and long networks, voltage rise is common in times of low consumption and high power feed-in by DER. Thus, voltage increases in particular occur when DERs are installed in regions with low consumption. In some cases, the electricity may even change direction and flow through the transformer to the higher voltage. Figure 36 illustrates the problem of maintaining proper voltage in the presence of reverse flows generated by the feed-in of DER.

For this reason, when connecting consumers and generators, DSOs ensure that the voltage will not exceed the limits under the worst-case scenario, meaning all expectable (also extreme) conditions, during the whole year and for every consumer connected to the same grid. They consider the worst-case scenario due to the absence of detailed data for the distribution network (for instance, measurement at the substation) and on the DER in their operation area.

Figure 36 - Voltage profile on an exemplary feeder with distributed generation



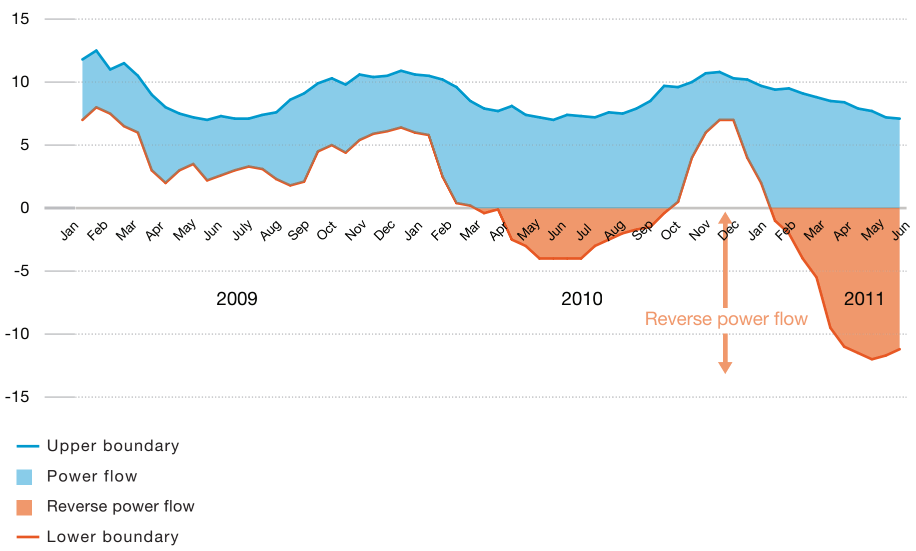
source: EPIA, based on AIT and E.ON Bavaria analysis, 2011

3.2.2. Overloaded grid components

Reverse power flows occur more often as the penetration of DER increases. As an example Figure 37 shows the power transferred on a German substation in an area with high penetration of PV since 2009. Reverse power flows can be even higher than the capacity of the transformer or the lines.

In case the above mentioned challenges (voltage rise or component overload) are identified, the conventional approach would be to connect the new generator to a stronger part of the grid, to limit temporarily the power that can be connected, or to reinforce the network. The first option is not always applicable, the second option contradicts policy objectives on the deployment of renewables, and the third requires sometimes costly investments.

Figure 37 - Reverse power flows at a German substation (MW)



source: EPIA, based on E.ON Bavaria figures, 2011

3.3. PV grid hosting capacity: status in Europe

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).

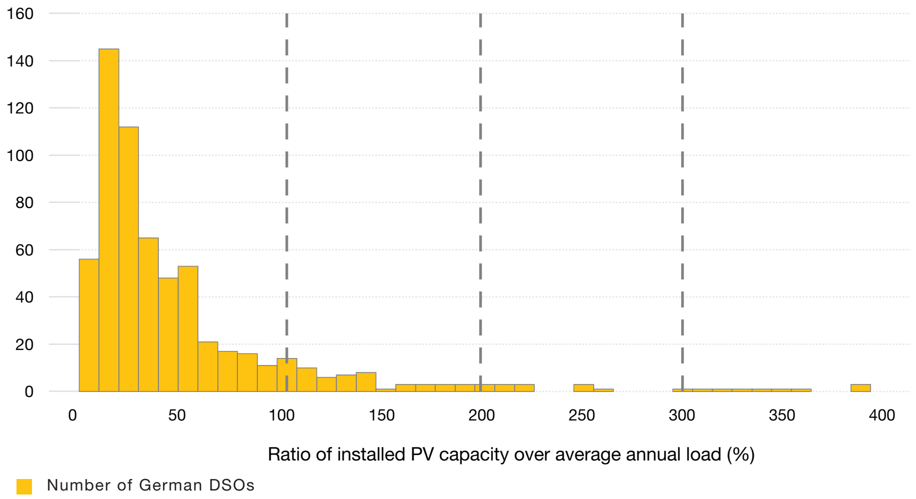
In practice, **there are two factors limiting the hosting capacity: the maximum loading current and the maximum operating voltage. The hosting capacity varies widely from one area to another depending on local characteristics of the distribution grid itself**.

It is common to classify distribution grids in two different categories: urban and rural. Urban grids supply many households in a small area; the transformer capacity and the number of consumers powered are high and the length of the line is short. Rural grids are characterised by much longer lines with lower transformer capacity and a lesser number of powered households.

The impact of DER deployment on distribution grids, the possible solutions to increase the hosting capacity and their cost-benefit ratio are different in urban grids and rural grids. For instance, overvoltage problems due to PV are virtually non-existent in urban networks (characterised by a greater load). In rural grids overvoltages are more probable due to the longer cable lengths.

Distribution grids can already take up significant amounts of PV electricity with little to no grid adjustments. As shown in Figure 38, some German DSOs host peak PV capacity which amounts to almost 400% of the average consumed power. And still there is room for further capacity increase.

Figure 38 - 2010 PV penetration in German distribution networks



source: EPIA, based on Fraunhofer IWES figures, 2011

One reason distribution grids can take up high levels of PV is the overloading capacity of distribution transformers. Distribution transformers are designed for a certain maximum continuous current, but can carry much more current during a limited amount of time. Also, the specific diurnal characteristic of PV feed-in results in distribution grid transformers being able to carry a peak PV capacity 50% higher than their rated power[13]. This does not even take into account local consumption, which further increases the PV installed capacity that can be connected before the transformer needs to be reinforced.

Generally the hosting capacity identified with worst-case assumptions for grid planning is lower than the real one. **Much more generation could be connected using better methodologies before voltage problems or reinforcement needs arise.**

3.4. Strategies to increase PV hosting capacity

The management and extension of the grid is becoming more and more challenging for DSOs, who are now managing an increasing number of DER.

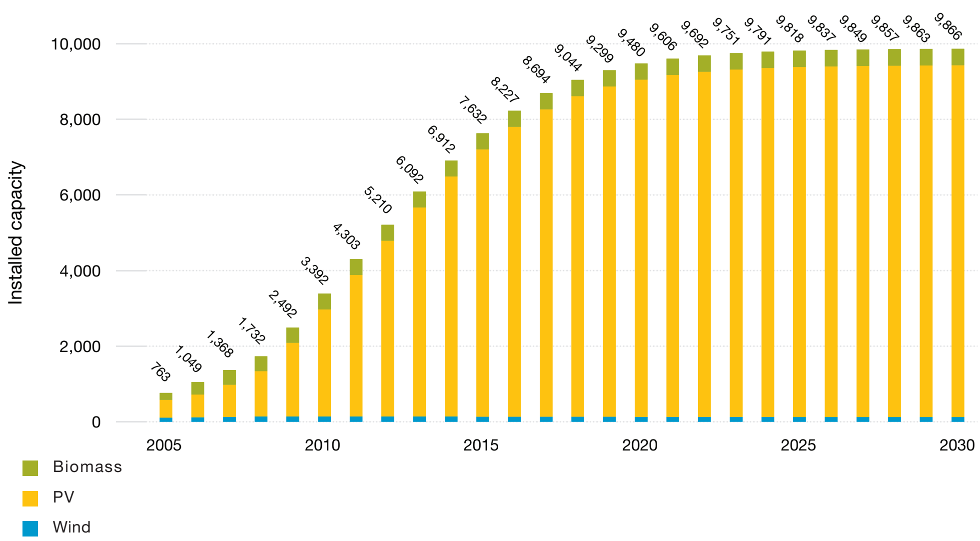
When the hosting capacity is reached in a certain distribution area, the "conventional" approach (connection to a stronger point, temporary limitation of the power that can be connected, or reinforcement of the network) is efficient but results in additional connection costs.

Moreover, it neglects to take into account new smart grid technologies. To apply these properly, long-term planning is needed. While DSOs analyse grid status before connecting larger units, this is not always the case for smaller (i.e. residential) units. Here the DSO often acts only after an issue is detected (for instance, by disconnecting PV systems in the case of over-voltages). **The absence of long-term grid planning for integration of small systems leads to bottlenecks that otherwise might have been avoided if measures were taken beforehand.**

To determine more precisely the local hosting capacity, a careful assessment of the grid is required, taking into account profiles of generation and consumption throughout the year by increasingly monitoring grids[14]. This will enable operators to develop cost-effective and innovative strategies to manage and improve their grids.

In order to better address the future challenges on their own grids, best practices observed in the field show that some visionary DSOs are today implementing more forward-looking strategies by running a prognosis exercise of the future installed DER (Figure 39). This is a new approach for most DSOs, who until now have been forecasting only the possible load increases and counteracting them only after the problems occur.

Figure 39 - Prognosis of the DER penetration on a specific part of a distribution grid (MW)



source: EPIA, based on E.ON Bavaria,"Future Grid" project figures, 2011

Experience or demo projects in regions where PV penetration is the highest in Europe have shown that these exercises are necessary to prepare investment strategies properly.

"Future Grid"

In the frame of the "Future Grid" project[15] launched in 2010, E.ON Bavaria is analysing PV injection to collect experience from a large number of PV systems in the MV and the LV grid.

E.ON has installed special measurement devices in substations and intelligent meters (measuring the load profile and the voltage). The final goal of this project is to produce a detailed modelling of feed-in and load behaviour which will serve as a basis for improved grid simulation and design.

The improved reinforcement and design strategies will be applied to the whole E.ON Bavarian grid area.

Such projects help DSOs to optimise integration strategies by developing smarter concepts, including:

- Developing different planning parameters (taking into account worst-case scenarios, but not basing them solely on these)
- Exploring and defining new specifications for equipment such as PV and wind inverters
- Using new equipment such as intelligent distribution transformers or decentralised storage
- Building experience on communication strategies with distributed generation

The "Future Grid" project, involving DSOs, PV system owners and inverter manufacturers, is not the only one in Europe. A few such initiatives in France, Italy and Belgium are also under way. But they can be difficult to conduct by smaller DSOs with fewer resources. Sharing the methodologies and results of these projects at the national and/or European level would therefore bring a clear added value.

Importantly, **there are no real technical barriers to further PV integration on distribution grids. New smart grid technologies may even increase hosting capacity further while bringing down the costs**. To increase the hosting capacity, the distribution grids can either be reinforced or extended or they can gradually evolve to integrate intelligence. Smart solutions or strategies involving gradually PV have to be developed to avoid or postpone network reinforcement costs. In any case DSOs need to consider small DER as a substantive part of their system and consider the future deployment of DER to determine their investment needs in order to plan on time; ad-hoc solutions usually are more costly.

3.4.1. Measures to address bottlenecks

As described earlier in this chapter, the distribution grid has historically been designed to accommodate the amount of power needed to meet the connected demand. Some local grid bottlenecks already occur and will increase with higher penetration of DER such as PV systems and wind turbines, or EVs.

Measures currently used to address bottlenecks are mainly based on increasing load management. However several new actions can and will have to be taken to increase PV grid integration while maintaining system stability within acceptable margins.

The use of classical measures will reduce the possible participation of DER in system operation. Moreover, these measures are not the most cost-effective options when looking to the future of DER penetration.

Cost-optimised strategies can be defined as a well-balanced and timely mix of different families of measures (Table 3).

Table 3 - Measures to address grid bottlenecks

Level of DER penetration ↓	Grid reinforcement measures	"Smart" solutions	DER participation in system operation
	Adjustment of the transformer output voltage	MV and LV grid monitoring	Passive feed-in
	Reinforcement or additional cables	Intelligent transformers	Response in case of "over/under" voltages
	Reinforcement or additional MV/LV transformers	Decentralised storage solutions	Control of DER in case of extreme networks conditions
	Reinforcement or additional HV/MV transformers	Demand side management	Active support to system operation

source: Based on E.ON Bavaria analysis, 2011 and EPIA, 2012

A complete identification or a description of all the measures mentioned above is beyond the scope of this report. However the overview presented in the table above gives a good picture of currently applied/discussed measures.

Notably, the goals of the different measures are not the same. Grid reinforcements are used to increase the possible transfer capacity on a specific network when the capacity limits are reached. Smart solutions and DER participation are based on the idea that it is possible to reduce or defer the need to upgrade distribution equipment. In a way, the goal of smart measures and DER participation is to make a better use of the existing infrastructure while maintaining or even increasing the level of security of supply and power quality.

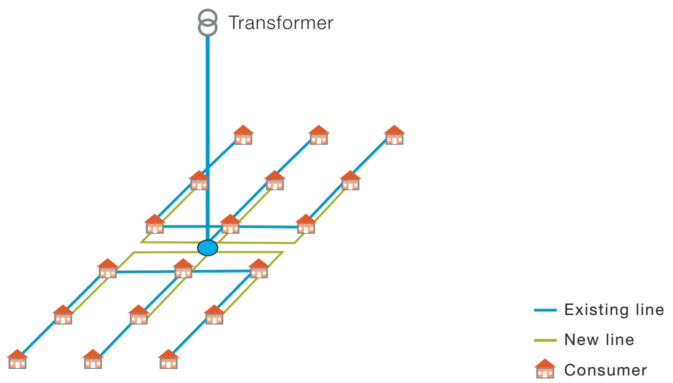
3.4.2 Grid reinforcement measures

Grid reinforcement comprises a set of measures that alleviate network elements from overloading (excess of current limits). Different measures are chosen from this set based on the application and the respective cost-benefit analysis. In general, grid reinforcement refers to doubling the existing circuit along the feeder, connecting a new transformer or building a new line with transformer (Figure 40).

Grid reinforcement is commonly used to address distribution bottlenecks. This is a **very effective solution for integrating DER, but it can be costly**.

It should be highlighted that distribution grid reinforcements are in general underground cables of proven technology. Thus, unlike the transmission grid, grid reinforcement on the distribution grid faces neither high technological challenges nor public acceptance issues.

Figure 40 - Schematic representation of grid reinforcement



source: Based on Consentec and EPIA analysis, 2011

3.4.3 Smart or innovative solutions

Improving the understanding of the grid: LV and MV grid monitoring

In the past distribution grids have been operated without real-time monitoring; instead, operations have been based on Standardised Load Profiles (SLP). However, due to the increasing penetration of DER, trends aim for more on-line monitoring. Grid monitoring helps improve the certainty of grid extension and operation and the visibility of TSOs on DER.

Such methods are already being introduced in MV networks by DSOs as a way to increase the hosting capacity of their grid. In the future, **affordable emerging communications technologies such as smart meters and automation infrastructures could further improve monitoring techniques, making them available for LV networks**. Furthermore, grid monitoring is a prerequisite to the active management of load and generation during grid operation to guarantee security of supply and a better DER integration. But the added value of real-time control of LV-connected DER by DSO still has to be demonstrated. Some research projects in Europe are already looking for solutions for an active network operation at the LV level. One example is the "DG DemoNet – Smart LV Grid" project[16].

"DG DemoNet – Smart LV Grid"

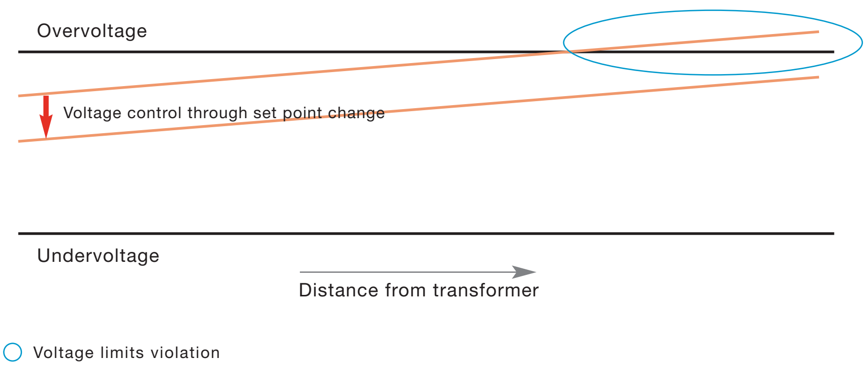
This research project, funded within the programme "Neue Energien 2020" by the Austrian "Klima – und Energiefonds", aims to enable an efficient and cost-effective use of existing grid infrastructures based on a three-step concept:

- Intelligent planning
- On-line monitoring
- An active management and control using a restricted communication infrastructure

Self-regulated or controlled distribution transformers

The initial voltage at the MV/LV transformer is usually set in order to keep the voltage within limits at any connected consumer. Feed-in from distributed generation may exceed the upper voltage limit (especially in rural grids).

Figure 41 - Set point change in case of voltage limits violation



source: Based on Consentec and EPIA analysis, 2011

Voltage at the feeding transformer can be dynamically lowered or raised (set point change) depending on the voltage situation on the grid by the self-regulated transformer (Figure 41). This would avoid exceeding the upper voltage limit in case of high feed-in electricity.

Theoretically, self-regulating distribution transformers could increase the possible feed-in power by up to 270%[15]. But in practice the increase will be lower. This type of asset exists for the time being only in pilot projects. The costs and benefits of a general use of this type of solution still need to be demonstrated.

The control strategy (self, local or external) will also be crucial when looking at the real added value of intelligent transformers. The presence of monitoring on the LV grid will also be a prerequisite enhancing the capabilities of this type of solution.

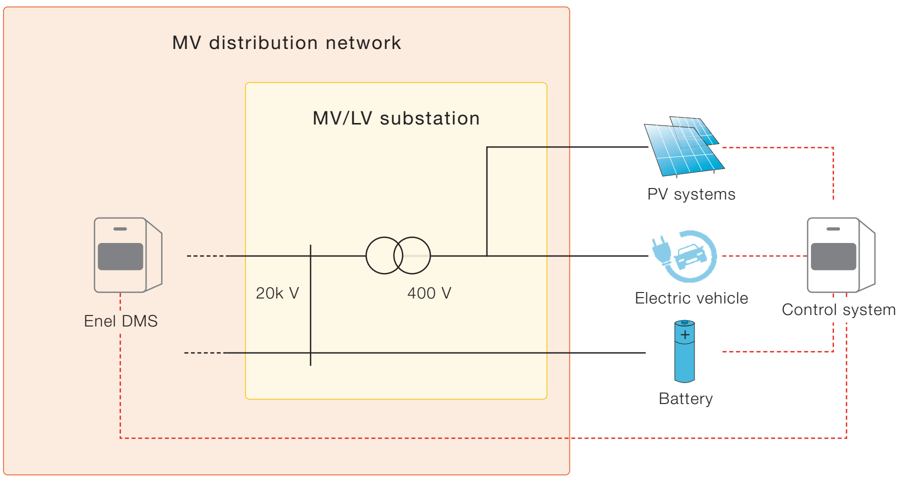
Decentralised storage solutions

Possible benefits to grid operation of using storage have already been described in Chapter 2. These include the ability to keep current and voltage within limits to shave peaks.

Storage can buffer a certain amount of load or generation based on their patterns. For a cost-effective use of storage, the key parameters are: size (it has to be large enough to reliably buffer the needed amount of electricity) and discharging strategy (electricity has to be discharged in times of low grid usage to avoid limit violations).

A relevant demonstration project developed by Enel Distribuzione in Italy involves the installation of storage solutions and a PV system (50kW) in Isernia, Italy. Within this project an MV feeder has been upgraded by installing a Li-ion battery of 750KVA-500kWh directly connected to the MV transformer, a local control system and a Distribution Management System (DMS) from Enel. From the LV side apart from the PV plant several EV charging points were connected.

Figure 42 - Isernia project: storage in operation



source: EPIA, based on Enel Distribuzione analysis, 2011

The goal of this smart project was to automate the network, enhance the voltage regulation and facilitate further RES integration and EV charging points. The storage will optimise both active and reactive power flows between the node and the feeder.

The practical use of storage by DSOs is still hindered by a lack of experience, high costs and regulatory constraints (such as the unbundling regime). In order to develop grid operation strategies using decentralised storage, some DSOs in Europe are now conducting demonstration projects. **As costs decrease, storage will become more and more a valuable alternative to grid reinforcement.**

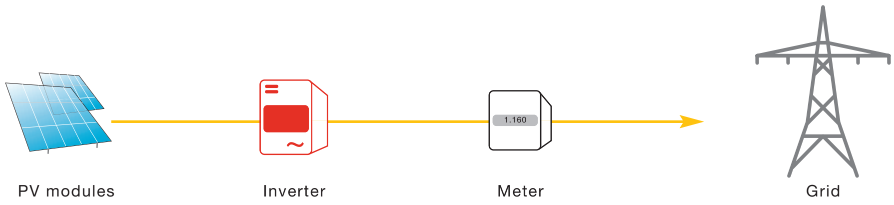
3.5. From a passive to an active part of power system operation: PV supporting the grid

3.5.1. Past: PV systems as passive players in the system operation

In the past, system operators did not consider PV to be relevant for the electricity system. On the contrary, they required every installation to switch off automatically and instantly as soon as a grid problem (e.g. a voltage or frequency deviation) occurred.

PV systems were considered as passive players by system operators (Figure 43).

Figure 43 - PV as a passive player in system operation



source: EPIA, based on SMA analysis, 2012

Inverters were designed only to maximise the yearly PV electricity production. Nevertheless, even at that time PV inverters hosted useful intelligence:

- Intelligence needed to efficiently transform DC into AC to avoid a decrease of the power quality at the connection point
- Maximum power point controller: A micro-processor maximises electricity production as actual irradiation and temperature vary
- Various safety and protection procedures: During start-up and operation, many protective functions are tested and continuously monitored
- Anti-islanding protection: Detects a disconnection from the grid and shuts down the PV system in order to ensure that no power is injected in a de-energised grid
- Interface to monitoring: Information on the production of the system is normally read by the inverter and can be forwarded to data loggers or other PV monitoring systems

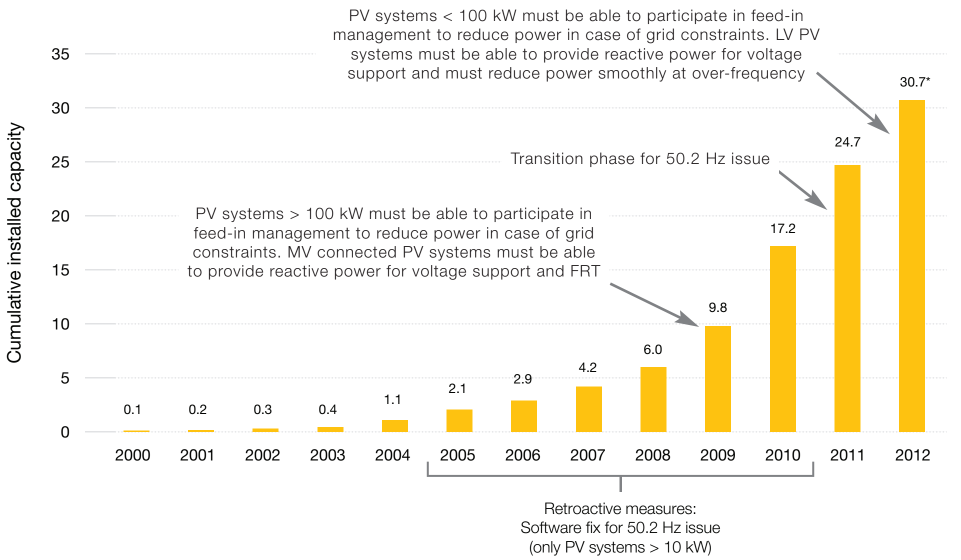
While concern about grid constraints was not significant, the occurrence of voltage problems in LV grids has already been alleviated at low cost by a progressive market introduction of three-phase inverters (or single-phase inverters in "three-packs") instead of single-phase inverters. Three-phase inverters ensure an equal loading of all phases or solve an existing imbalance at no extra cost. However, as of today they are still not widely used for systems below 10 kW. **When possible, the use of three-phase connected inverters should be promoted as it is one of the cheapest measures to alleviate voltage problems at the low voltage level.**

3.5.2. Present: PV systems as responsive players in the system operation

As distributed generation increased, grid operators realised that new grid codes were urgently needed. The grid codes in some countries have changed dramatically and now require not only that PV and wind installations stay connected during grid disturbances, but also that they be able to support system operation in a responsive way.

New requirements were introduced progressively, first for installations connected at the HV level, then at the MV level. Some of these requirements are now being extended to installations connected to the LV grid. As an example, Figure 44 illustrates the evolution of requirements for PV in Germany as PV deployment has increased.

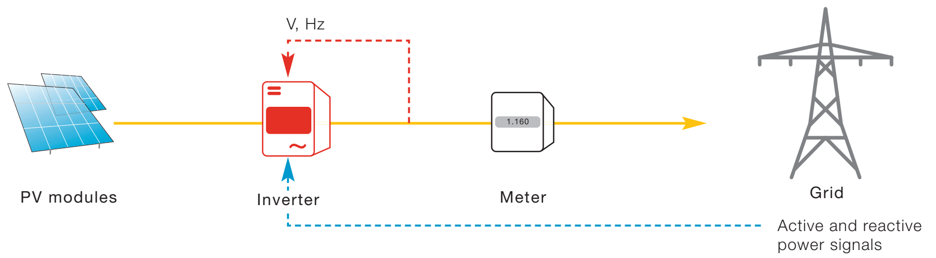
Figure 44 - Evolution of the German grid code and regulations compared with PV deployment (GW)



source: Based on EPIA and SMA figures, 2012
* EPIA forecast

PV systems are becoming considered as responsive players by system operators (Figure 45).

Figure 45 - PV as a responsive player in system operation



source: EPIA, based on SMA analysis, 2012

3.5.2.a Active power reduction in case of over-frequency

In the past, PV systems were required to disconnect from the grid when the frequency was exceeding the permitted range. However, the sudden disconnection of a large PV power generation would have had a negative impact on the system stability as TSOs may have not been able to compensate for this loss (see the 50.2 Hz section in Chapter 2).

Therefore, **in Germany, Italy and Belgium grid codes have been recently revised to require PV systems of all sizes to progressively reduce their power output as frequency increases. Other countries must urgently integrate this requirement in their grid code to avoid costly retrofitting of the existing PV systems**.

3.5.2.b Fault ride-through capability

A fault on the system causes brief voltage drops around the fault location. Generation units are meant to disconnect from the system if voltage falls below a certain limit for a defined period of time, for instance when a feeder is disconnected for maintenance purposes.

If only a short voltage drop appears and generators immediately disconnect, the system balance might severely be affected. Therefore, short voltage changes should be subject to "ride-through". Different national grid codes require PV systems (MV level) to stay connected during the voltage disturbances and to inject reactive power during grid faults. **As a result they contribute to the resolution of the incident and help to trigger grid protection devices. However, this capability has to be assessed at the LV level.**

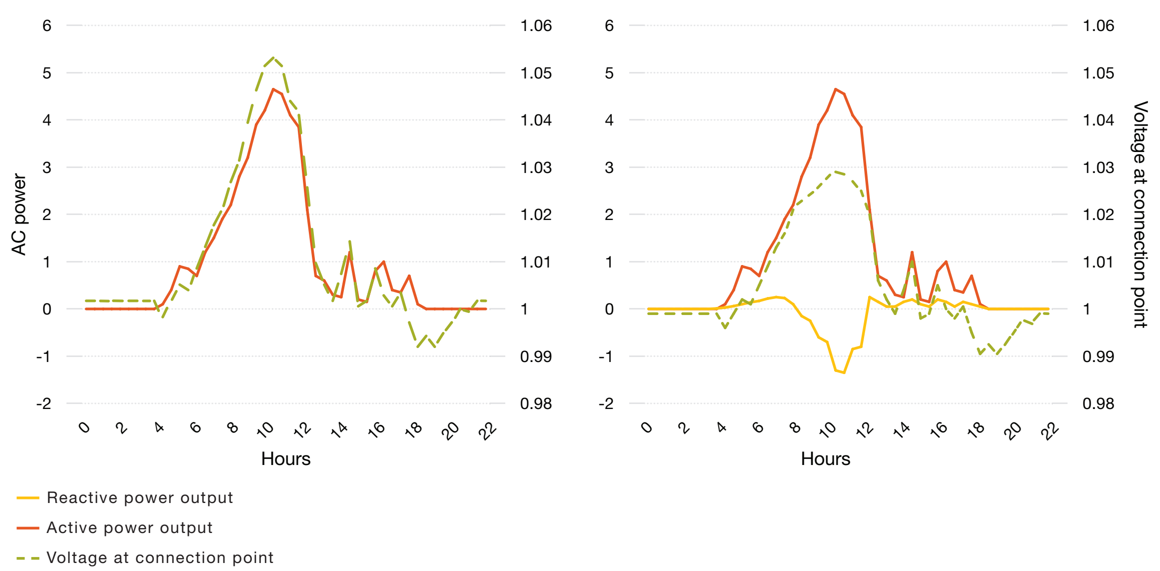
3.5.2.c Provision of reactive power and voltage support

Keeping the voltage between defined limits and especially avoiding overvoltage is becoming a primary concern of DSOs due to the increasing number of generators connected to the distribution network. This makes the connection of additional distributed generators difficult or impossible without grid reinforcement. Furthermore, devices connected to the grid, like large electrical motors, consume reactive power. The transport of reactive power reduces the transmission capacity and increases losses.

Since 2012 in Germany, PV systems bigger than 3.68 kVA have been providing static grid support by reactive power control. The control strategy depends on the size of the PV system, the voltage level and finally the local characteristics of the grid. The control strategy can be based either on target values, a predefined schedule or on demand characteristic curve (function of the voltage or the active power).

Figure 46 illustrates the effect of voltage support provided by a PV system at its connection point with the LV grid. The strategy simulated in this case is based on a characteristic curve: The reactive power is regulated as a function of the supplied active power[17].

Figure 46 - Impact of PV voltage control



source: EPIA, based on Fraunhofer IWES figures, 2010

The voltage-lowering effect of reactive power provision will depend on the characteristics of the relevant grid (location and voltage level). For instance, the supply of reactive power has significantly less effect at LV than it does on the HV grid. Instead, the feed-in of active power causes a noticeable increase of the voltage at the same level; compensation of the voltage increase is essential.

As this requirement has virtually no cost for small PV systems, **reactive power provision should be taken into account everywhere as a possibility to increase the PV hosting capacity of the grid**. For instance, twice as many PV systems may feed-in ideally 80% more active power on the same LV network if they are providing reactive power[18].

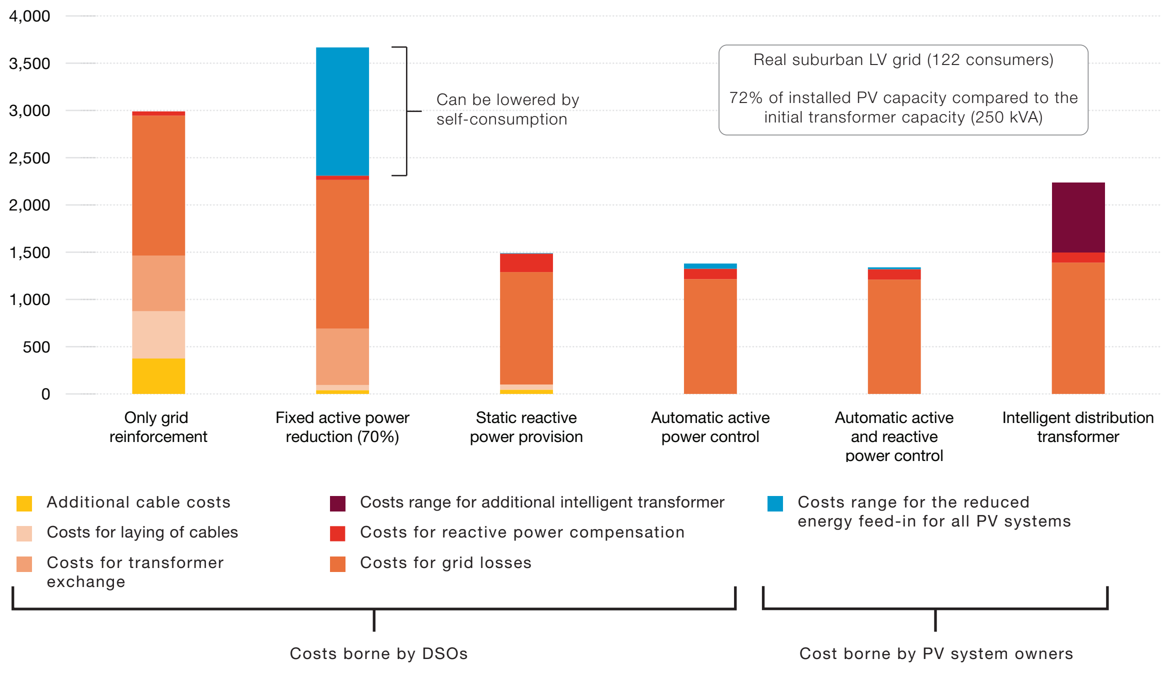
3.5.2.d PV participating in voltage support strategies

Active and reactive power control as well as controllable grid assets like intelligent transformers can be used to control the voltage. Different innovative strategies involving PV systems can be used to control voltage and avoid the need to reinforce the grid. They are based on various combinations of active and reactive power control.

Figure 47 presents a cost-benefit analysis of the different voltage control strategies used on a LV network[19].

It is important to note that these results should be considered as valid only for the investigated grid network. But they are confirmed by other studies[19, 20, 21] conducted by DSOs, inverter manufacturers and research centres: **The use of reactive power control strategies involving PV systems for maintaining the voltage within the statutory limits is an effective solution. This means in practice that costly network reinforcement could be avoided or postponed thanks to the control capabilities of smart inverters.**

Figure 47 - Cost-benefit analysis of different voltage control strategies (€/year)



source: EPIA, based on Fraunhofer IWES figures, 2012

3.5.2.e PV participating in the feed-in management

If a section of the MV or higher-level transmission grid network is temporally overloaded, DSOs should be able to remotely control the DER feed-in. Furthermore, active power reduction is exceptionally permitted in cases where local grid reinforcement measures are not yet completed. Depending on the size of the PV systems, the voltage level and the country different approaches can be used.

Using remote control for large PV systems

For instance, in some European countries (Belgium and Germany) PV systems connected to the MV system are capable of receiving remote set values for their active power output. DSOs are able to control PV generation when needed.

Capping of power output for small PV systems

Even if smart distribution grid management for interacting with small PV systems is not deployed, voltage problems and network equipment overloading in LV grids can already significantly be alleviated by lowering the inverter-power ratio of Alternating Current to Direct Current (AC/DC). For instance it is now a proposal for the LV guidelines in Germany to introduce a 70% cap using this ratio, unless the installations are controllable by the DSO. This way, 43% more PV peak power, producing 36% more PV electricity could be connected (energy losses due to the 70% limit are comparably low: approximately 5%).

However, capping of power output induces a generation loss for the system owner. One should therefore only consider it as a transition measure or one to use in combination with a small storage solution.

3.5.2.f Non-firm connection: Is curtailment an effective PV grid integration measure?

System operators are currently analysing the possibility of extending the use of active power management to postpone or avoid network reinforcement. The connection to the grid in this case is considered as non-firm. PV systems will be allowed to feed in only if the power is below a certain threshold. The PV power output can be either capped or remotely controlled. The latter results in lower production losses for the system owner but is possible only for large systems (in Germany the threshold is >100 kW).

Analysis conducted in France[22] showed that for rural feeders, it is possible to reduce by 30% the PV integration cost compared to grid reinforcement strategies by curtailing 5% of the electricity produced.

At first glance, this curtailment postpones grid reinforcement and therefore could be considered in some limited cases as a measure to integrate PV. But it is counterproductive regarding the EU's climate and energy targets. It wastes CO_2 neutral electricity and it simply postpones a grid enhancement that will still be needed. Moreover, it also discourages the deployment of other measures to alleviate grid constraints, which are then not investigated further as the problem is perceived as "solved". **As PV inverters can feed in reactive power for virtually no cost, active curtailment should be envisaged only as a last resort measure, when reactive compensation is no longer sufficient to avoid voltage limit violations**.

To avoid unfair treatment and discrimination among PV producers, the use of curtailment as a way to increase the hosting capacity of the distribution grid should in any case remain optional and subject to a contract under the scrutiny of the national regulator and on the basis of clear and transparent criteria. Better deployment strategies – promoting the installation of PV systems where the electricity can be locally consumed or where the grid is stronger – with long-term planning horizons will also reduce the potential need for curtailment.

3.5.3. Challenges ahead

Going forward, some challenges remain: the need for a better match between PV production and consumption; the development of peak-shaving strategies; and the need for more clarity about the services PV systems should provide.

3.5.3.a Better match between PV production and consumption

If PV systems are installed where the grid has been built to carry a high load level that ideally occurs during daylight hours, the feed-in of PV electricity does not result in a need to reinforce the grid. In other words, **decentralised power production has no impact on the distribution grid as long as this power is locally consumed**.

Hence, the cost for PV integration will vary dramatically depending on the consumption level of the distribution area and on existing DER penetration. When trying to minimise the cost of PV integration, the first and the simplest measure is to install PV systems where the load is. **Self-consumption and/or local consumption can reduce significantly the impact on the grid caused by the increasing feed-in from distributed generation**. Household storage or PV/heat pumps solutions are now becoming available on the market. PV system owners can install batteries to increase their self-consumption from an EU average of 30% to 70% (with household storage) and 40% (with PV/heat pumps)[23].

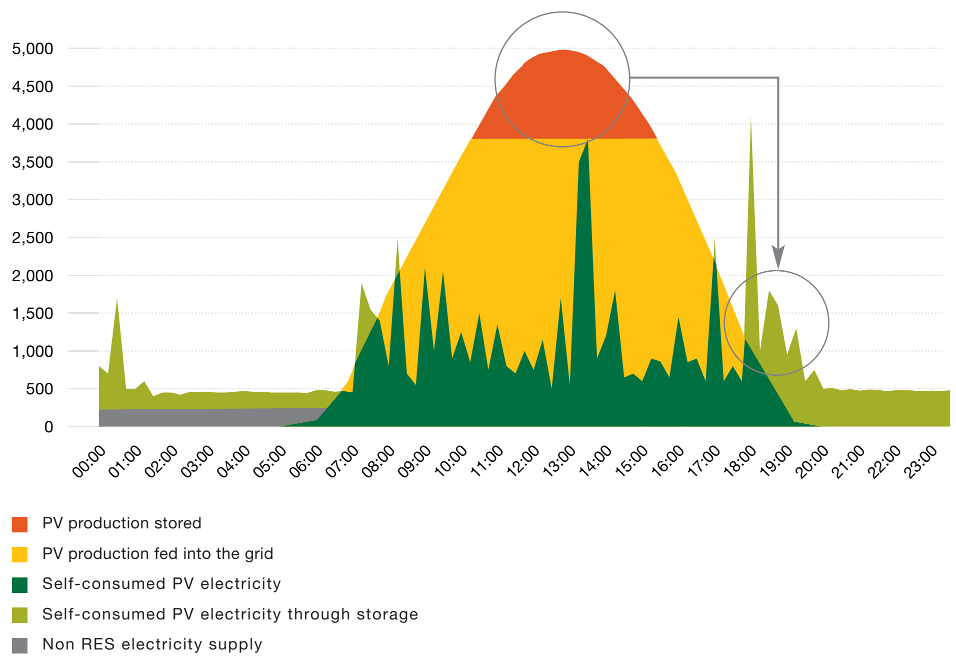
3.5.3.b Development of peak-shaving strategies

Even if PV production and consumption are correlated, PV systems are not producing during the evening peak consumption. This is especially the case at the household level, where the daily peak consumption is at around 20:00.

As peak values are used as the reference points for the design of distribution grids, their decrease is important for cost-reduction strategies.

To achieve a cost-effective large-scale PV deployment, optimised strategies[24] to reduce peak production and/or consumption will have to be implemented using DSM measures and/or storage at the household and/or local level (Figure 48).

Figure 48 - Peak-shaving strategy using storage at household level (W)



source: EPIA, based on SMA analysis, 2012

3.5.3.c Clarity about requirements for PV systems

Grid codes and grid integration strategies vary significantly from one country to another. Some countries still consider that PV systems should behave as passively as possible. Only a few countries take into account the ability of inverters to address the impact of PV on the distribution grid.

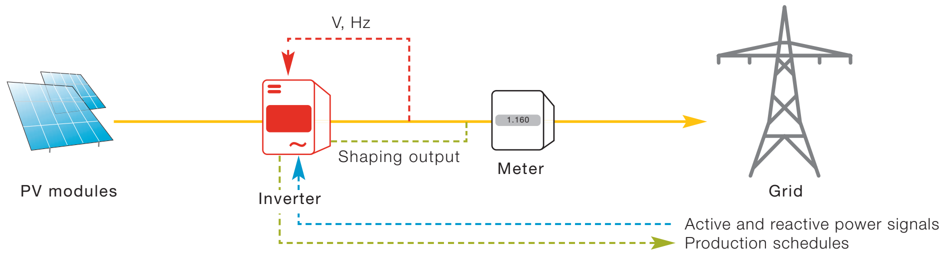
Moreover, it is often unclear what requirements PV inverters should meet in order to ensure optimal local power quality. **Enhanced dialogue between the PV industry and DSOs is therefore needed**. The need to harmonise requirements is important to avoid product variance and instead favour a cost-effective PV deployment[25]. While a network code is currently being developed at European level that would partially respond to this need, a proper integration of European standards in national grid codes will ensure a cost-effective harmonisation process.

3.5.4 Future: PV systems as active players in the system operation

The next step for PV systems will be to assume an active responsibility in grid operation by helping system operators not only to solve issues but to manage their own systems (Figure 49). Active inverters will participate in the operation of the power grid, not only by responding to signals but also by taking responsibility in the process:

- deciding the best option to react to signals
- deciding on production schedules for the grid operator and following them (e.g. by shaping the power output)

Figure 49 - PV as a responsive player in system operation



source: EPIA, based on SMA analysis, 2012

It is currently difficult to define the exact limits (technical or financial) for PV systems to provide ancillary services such as voltage support during night, virtual inertia or frequency control. The future capabilities of PV systems and the associated cost are currently analysed in different EU or national projects such as REserviceS and PV GRID.

Synergies among PV systems, storage solutions and smart consumers (such as heat pumps or electric vehicles) will also be crucial to enhance the real grid support capabilities of DER. Energy management systems will integrate these entire new smart concepts.

To unlock these capabilities, **demonstration projects and communications protocols and infrastructures** with system operators or third parties are unavoidable. In this field, **European standardisation** will be crucial to provide cost-efficient solutions.

metaPV – PV Smart grids in practice

"metaPV shows that reactive power management by smart PV inverters can significantly increase the hosting capacity of the grid at a competitive cost" says Dr. Achim Woyte, R&D manager and project coordinator at 3E.

metaPV, an EU-funded project, brings together DSOs, inverter manufacturers and renewable energy experts from different countries. In this international collaboration the consortium investigates how large-scale PV can be integrated into the distribution system using smart grid technology.

metaPV is the first-ever PV smart grid demonstration that combines advance monitoring with active inverter control. The goal is to show how far smart grid technology can reduce or postpone conventional grid reinforcement. For two market segments, residential and commercial, metaPV demonstrates the additional benefits of active grid support. Enhanced control capabilities in PV inverters allow local and coordinated voltage control, autonomous grid operation, FRT capabilities – with positive interim results.

3.6. Involving PV in smart grids

3.6.1. Standardisation and smart meters

3.6.1.a Standardisation

Grid codes and requirements, but also the services that PV could provide to the grid, form the functional basis of PV system integration in the grid. **Clear standards for inverters and communication infrastructures will need to be identified and used in the near future, so as to ensure that such integration takes place in a cost-effective way**.

Effective standards would, in the short run, allow for a smoother provision of services, required features and control. They would also contribute to reducing the variance-related costs among products. In the longer run, standards will lay the groundwork for a common integration of PV systems into the grid, avoiding the risk of expensive retrofitting measures.

Only very recently, the European Standardisation Organisations (ESOs) have started moving towards an improved framework, notably through the development by CENELEC of the standard for micro-generation and the technical specification for distributed generation. **It is important that standards, while ensuring a full integration of PV services and requirements in the grid, be kept flexible enough to allow for inverters to fully develop their range of innovative products – therefore providing grid operators with state-of-the-art features.**

3.6.1.b Smart meters

The deployment of electric vehicles, heat pumps, storage and smart household appliances will, together with the rise of PV generation, multiply the amount of information to be communicated at each connection point at consumer level.

The main issues linked to ensuring that the appropriate communication flows take place are:

- Communication reliability – how to ensure that communication is seamless and trustworthy
- Communication content – what should be communicated
- Cost-effectiveness – a viable framework is essential in order to ensure practical feasibility

Communication reliability is of paramount importance in a stable and secure system. Trusted communication devices between producers/consumers and DSOs already exist: the meters.

Grid operators will need to receive detailed and real-time data on active and reactive power input and off-take from the producer/consumer. In the context of an increasing number of grid operations managed directly by DSOs, these operators will need to remotely control, in specific cases, the PV generated power flow.

Current meters are usually not conceived to provide this kind of communication. **New, smarter meters** are currently being developed. These **could ensure a thorough communication between prosumers and grid operators, on all relevant power flow measures**. This would guarantee that all the services provided and marketed by PV producers or required of PV systems are properly measured. The corresponding grid operations could take place at individual or aggregated level, depending on cost-effectiveness.

According to EU legislation, the deployment of smart meters is the responsibility of Member States on the basis of a cost-benefit analysis. Many of the already performed national analyses have positively considered specific functional requirements on import and export of electricity and reactive metering. This type of functionality needs to be implemented in a cost-effective way, namely through the adoption of appropriate standards. Such standards would be aimed notably at avoiding expensive retrofitting, in case some features are overlooked, but also at reducing the risk of incompatibility among devices, hence limiting variance-induced costs.

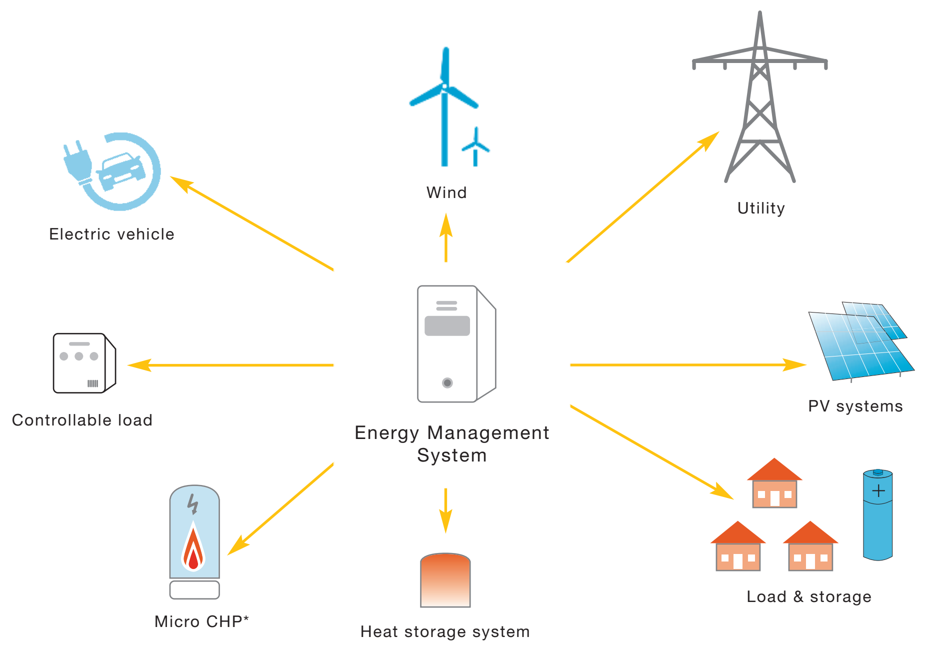
Finally, the possibility of developing a standardised direct interface between the meter and the PV system (inverter) should be properly considered. A plurality of closed communication protocols would also increase system costs. This is why **future communication protocols should remain open and be established at the EU level**.

3.6.2. PV in Virtual Power Plant portfolios and aggregation

No matter the type of lines and the energy efficiency measures that can be implemented, producing energy in centralised power plants and transporting it via long transmission lines to the customers always includes high power losses. Therefore distributed generation and especially RES, such as PV, and energy storage through distributed system can save costs.

The concept of the Virtual Power Plant (VPP) corresponds to an aggregation of different small distributed generation units, fixed and variable loads and energy storage systems that work together as a distinct power plant. The heart of a VPP is the Energy Management System (EMS). It enables the information flow between the different VPP components and controls them by sending signals (Figure 50).

Figure 50 - Simple representation of a Virtual Power Plant (VPP)



source: EPIA, 2012
*CHP: Combined Heat and Power

VPPs will enhance the full participation of distributed generation as PV in the system operation and in the energy market by providing a set of functionalities:

- **Participation in balancing**: This has been already demonstrated in Chapter 2, which described the predictable aggregated output from a large portfolio of PV or VRE in general. A technical VPP can contribute to system balancing by providing ancillary services (TSO-related functionality)
- **Contribution to voltage control**: This can be done by, for instance, controlling the aggregated active and reactive power output (DSO-related functionality)
- **Contribution to meeting the active and reactive power schedules**: This is strongly related to the electricity market. Efficient energy management can reduce possible interaction with the "power exchange" intra-day market to meet the demand
- **Contribution to congestion management**: This can be achieved by monitoring and controlling efficiently the power flows inside the area of the VPP
- **Participation in the electricity market**: Services/functions from a commercial VPP include trading in the wholesale energy market, balancing of trading portfolios and provision of services (through submission of bids and offers) to the system operator. The operator then can be any third-party aggregator or a Balancing Responsible Party with market access; e.g. an energy supplier

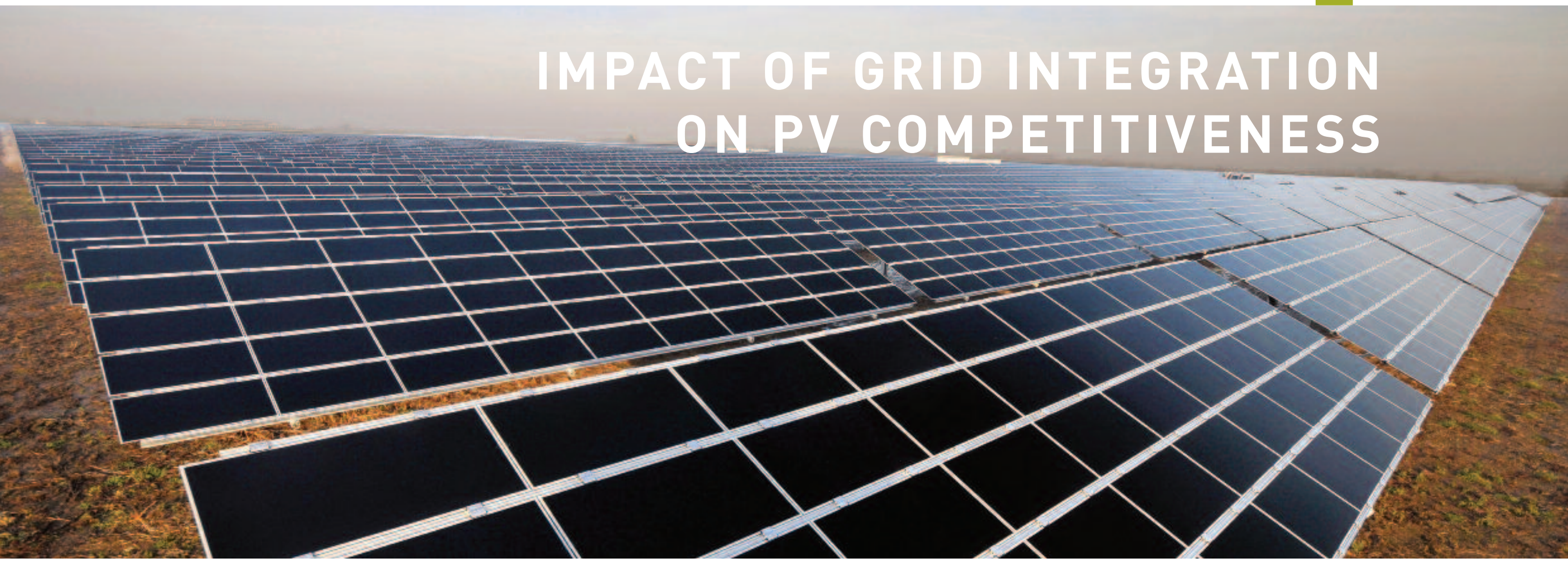
3.7. Conclusions

This overview of challenges and solutions at distribution level leads to the following conclusions:

- **Large-scale PV integration depends on PV hosting capacity**, which is defined by two factors: the maximum operating voltage (due to the voltage rise) and the maximum loading current (due to the overload of grid components)
- **In some parts of Europe, distribution grids can already take up significant amounts of PV electricity with little or no grid adjustments**. But worst-case assumptions are often used to estimate the hosting capacity. This leads to a lower hosting capacity than the real one. More generation could be connected before having to reinforce the grid
- **The traditional approach used by DSOs to address challenges in the network leads necessarily to the adoption of effective but costly solutions such as grid reinforcement**
- **Long-term planning is needed to address the challenges more cost-effectively**. In particular DSOs will have to assess the status of their grid, monitor the behaviour of their grid with DER presence and predict future DER capacities in their operation area. This would lead to smart, cost-effective investment strategies
- **The use of smart strategies or equipment (like storage and intelligent transformers) can avoid or postpone the use of grid reinforcement**
- **PV systems are already able to alleviate the impact they have on distribution grids**. The use of PV's true capabilities (for instance voltage control) is cost-effective compared to traditional strategies
- **Curtailment of PV power output as a way to increase the hosting capacity of the distribution grid should remain optional and envisaged only when other measures have been exhausted**. To avoid unfair treatment of PV generators, curtailment should be subject to a **proper contract** under the scrutiny of the national regulator

4

IMPACT OF GRID INTEGRATION ON PV COMPETITIVENESS



This study has shown that integrating a large share of variable renewable electricity is technically feasible under both 2020 and 2030 scenarios. Demonstration projects and best practices have proven that a large PV integration is possible. Applying the most optimal solutions in each case is mainly a question of cost vs. benefit. This chapter analyses the cost impact of these solutions on PV competitiveness itself.

Chapter 1 of this study explored how competitiveness of PV can be affected by some dynamic parameters, such as system prices and cost of capital. But the question remains: How will grid integration challenges affect PV competitiveness?

4.1. Impact of requirements, grid costs and taxes on PV competitiveness

As shown in previous chapters, PV generators are able to provide grid integration solutions. Some of the measures needed could, however, have an impact on PV's generation cost. These potential additional costs include: requiring additional PV inverter functionalities; curtailing a part of PV production; and exposing PV generators to grid costs and taxes even when PV electricity is self-consumed. Each has a specific impact on the moment when PV competitiveness could be reached.

4.1.1. Impact of additional inverter costs

In order to provide system support to network operators, inverter capabilities may have to be enhanced in the future. Because of the relatively low share of inverter cost within the overall PV system cost, a 20% additional cost to improve inverter technology would have a limited impact on competitiveness, increasing the overall PV system cost by an average of 2%. This represents an overall negligible impact.

4.1.2. Impact of curtailment

As shown in Chapter 3, curtailing PV production is perceived – in some limited cases – as a tool to increase PV hosting capacity at the distribution level. Assuming a 10% curtailment and reflecting it in the LCOE shows that it would have a significant impact on PV competitiveness; in some cases delaying it by up to two years.

The impact is most severe in the utility-scale segment, where assessing competitiveness requires comparison with wholesale electricity prices. In this case, no EU country reaches competitiveness before 2018 (France, Italy) in the best case (low cost of capital, average irradiation levels, optimistic scenario for prices evolution).

Curtailment has a direct impact on the revenue stream of PV system owners, even when the cuts are limited. It would delay the moment when competitiveness could be achieved. It should be used only under very strict conditions in order to avoid increasing overall system costs and if other more cost-effective solutions are not available for the DSO.

4.1.3. Impact of exposure to grid costs and taxes for self-consumed electricity

Self-consumed electricity reduces the electricity bill of the prosumer, who nevertheless continues to pay grid costs and taxes on the volume of electricity effectively withdrawn from the grid. When assessing competitiveness of PV in 2011, EPIA considered that a 30% self-consumption ratio was realistic in the residential segment. In the commercial and industrial segments, a 75% ratio was considered. Some recent evolutions have shown that the **structure of the electricity tariffs may progressively change and become capacity-based**, meaning that they will depend on the user's potential peak consumption (the capacity of which is fixed), rather than its actual consumption (which is variable).

Therefore this section assesses two situations to determine the impact on PV competitiveness if PV system owners had to pay grid costs and taxes on the whole volume of electricity, i.e. including on the electricity produced and consumed on-site:

- Grid costs must be paid by the PV system owner even for electricity that is self-consumed
- Grid costs and taxes must be paid by the PV system owner even for electricity that is self-consumed

The impact depends on the segment and country characteristics. In countries with high taxes and high grid costs, payment of grid costs also for self-consumed electricity can have a significant impact on the competitiveness of a PV system. However, when taxes and grid costs represent a smaller part of the final electricity price, the impact is less important. For utility-scale applications, the impact is by definition zero, since no electricity is self-consumed.

In the **residential segment**, the payment of grid costs on self-consumed electricity delays competitiveness on average by one year (Spain, Germany) or two years (France, Italy, UK). If taxes have in addition to be paid on the volume of self-consumed electricity, competitiveness is delayed in Germany and France by six years (2020 instead of 2014), by five years in Italy (2017 instead of 2012), and by four years in Spain (2019 instead of 2015).

In the **commercial segment**, the impact in Italy is negligible; competitiveness could start to be reached in 2013 instead of 2012. In France, UK and Spain, paying grid costs delays competitiveness until around 2020. In the case of payment of all taxes and costs on self-consumed electricity, PV competitiveness will not be achieved in France before 2022 (at the earliest) and the impact in Germany and Spain is very important, with more than eight years of delay.

In the **industrial segment**, the situation is similar: low prices of electricity shift the competitiveness point after 2021 in all cases except in Italy (2016).

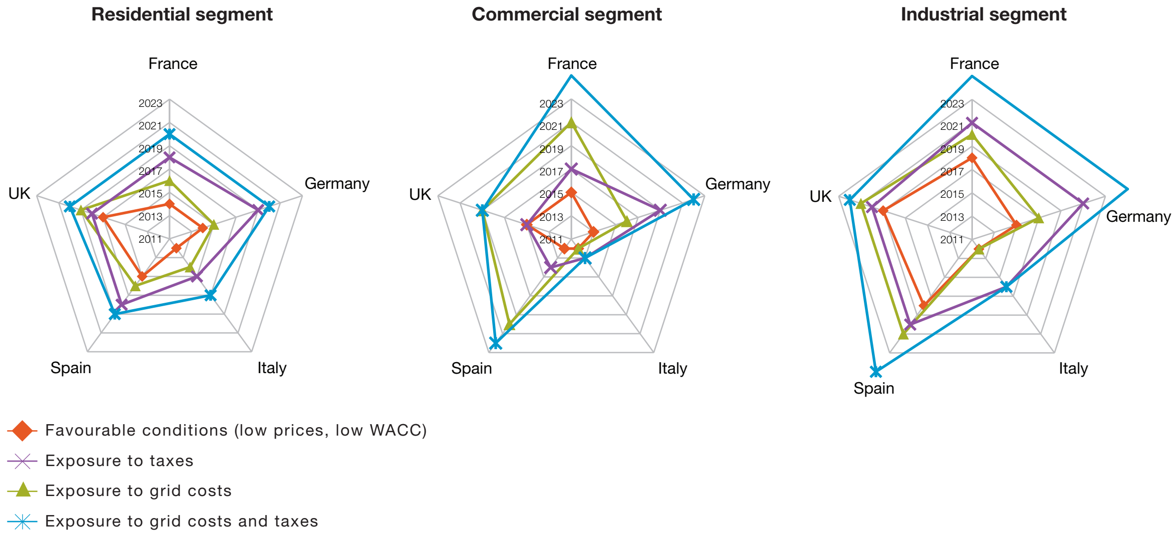
4.1.4. Summary

Figure 51 shows the impact of the different measures described in the previous sections on the competitiveness dates for prosumers. The calculations have been based on the following assumptions (Annex F):

- Average irradiation data for each country
- Low cost of capital
- Optimistic price evolution scenario ("low prices" scenario)

It should be remembered that higher costs of capital or a less optimistic price evolution can delay the starting point and then shift even more into the future the date at which a segment in a country becomes competitive.

Figure 51 - Impact on PV competitiveness of exposure to grid costs and taxes of self-consumed electricity



source: EPIA, 2012

4.2. Impact of “smart solutions”: storage and DSM

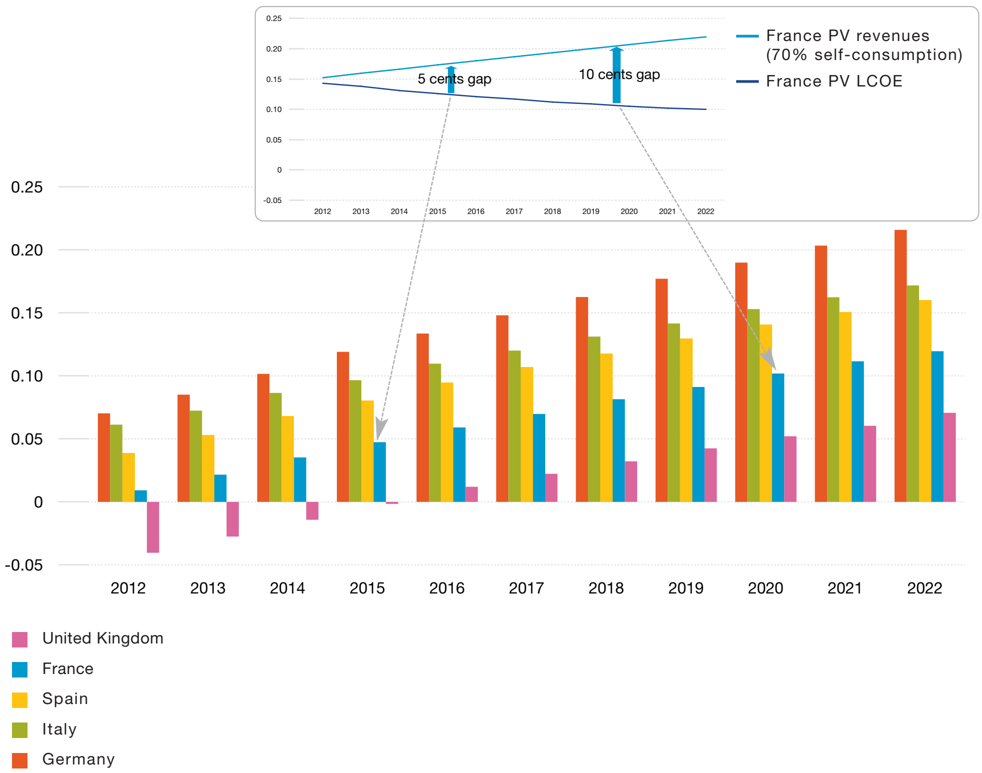
4.2.1. Impact of storage

In the case of residential installations, using storage for short-term supply side management – shifting a part of the PV production to the evening peak or the night – could increase the percentage of self-consumed electricity from maximum 30% without storage to around 70%.

Assessing the impact of storage on competitiveness requires estimating when the cost of a storage system will be outweighed by the increase in self-consumption. This assumes that excess PV electricity can be injected into the grid and sold at the wholesale price of electricity. Therefore any reduction of excess generation will lead to an increase in savings, higher than the decrease in revenues from PV, injected into the grid.

Figure 52 illustrates when storage starts making economic sense for PV system owners. The upper blue curve represents the net present value of revenues during the lifetime of a PV system in case of increased self-consumption due to storage (example of France). The lower blue curve represents the declining PV LCOE. The arrow represents the time when respectively 0.05 and 0.10 €/kWh can be invested in a storage system or any other kind of support measure.

Figure 52 - Window of opportunity to use storage - Difference in revenues and generation cost (LCOE) of a residential PV system (€/kWh)



source: EPIA, 2012
note: Optimistic price evolution scenario, low cost of capital and average irradiation data are considered

Several storage technologies are commercially available today, but so far none has benefited from a large market deployment in the electricity sector in general and in combination with PV in particular.

A level of 0.10 €/kWh for a storage system will be reached in 2014 in Germany in that scenario, in 2016 in Italy and 2017 in Spain. France should reach it in 2020 while the UK will not reach such a level before 2022 (Figure 52). This scenario is based on an optimistic price decrease assumption, with an average irradiation level in all five countries. **It mainly illustrates the widening gap between PV electricity cost (LCOE) and the revenues that could be generated by a PV system combined with storage.** It also illustrates that storage costs above 0.15 or 0.20 €/kWh will hardly become competitive before the end of this decade.

Storage solutions available at 0.10 €/kWh can be considered as optimistic. However, this should be a target value for the industry and other stakeholders. Finally, the possibility of storage providing a combination of services has not been taken into account in these calculations. With the proper incentives, that would close the gap even more.

4.2.2. Impact of demand side management

DSM already exists. For example, using a heat pump for hot water allows an increase in self-consumption in the residential segment from 30% to around 40%. Considering the cost of the heat pump as zero (because it replaces another hot water system), **a combined PV/heat pump system today represents one of the best ways to increase self-consumption and therefore the competitiveness of PV**. In the commercial segment DSM solutions should easily enable close to 100% self-consumption.

In most cases, DSM solutions can bring forward the average competitiveness date by two to three years considering all scenarios. It can therefore be assumed that, with DSM solutions such as using heat pumps with average irradiation conditions and with a reasonable cost of capital, competitiveness could be reached today in France, Germany, Spain and Italy, while the UK will need to wait until 2015. In Annex F a detailed analysis of the impact of DSM measures on competitiveness is available.

4.3. Conclusions

Forecasting PV pathways to competitiveness requires considering multiple factors. The high impact of the cost of capital, for instance, can completely change the picture of competitiveness in a country and in a market segment and offset gains in system prices, operation costs or even a higher level of solar irradiation.

The choice of measures to ease PV integration into the electricity grids and the electricity sector in general can have an important impact on PV competitiveness as well. Smart DSM solutions can improve the competitiveness of PV, while other measures aiming at improving distribution grids hosting capacity can have a negative impact: sometimes limited (active inverters), rather limited (low levels of curtailment) but also really significant (payment of grid costs and taxes in the case of self-consumed electricity).

Assuming a storage cost of 0.10 €/kWh, the combination of PV and storage could be competitive before the end of the decade in Italy, Germany and Spain. Storage costs below 0.10 €/kWh will be needed to achieve competitiveness before 2020 in France and the UK.

5

POLICY RECOMMENDATIONS

PV will cover at least 10% and up to 25% of the electricity demand in Europe in 2030.

There are virtually no technical limits to PV integration into the system. But a closer collaboration among TSOs, DSOs, and conventional and renewable players will be needed in order to identify cost-optimal solutions. PV in itself will be one of these solutions, through the provision of grid services and, as a last resort, contracted curtailment.

System operation will become more complex, since PV and wind together will exceed occasionally the absorption capacity of the network. To maintain system security, it will be crucial to fully exploit and develop system flexibility. Here again, PV will be part of the solution, in combination with storage and DSM.

As Europe plans investments in new energy infrastructure, these evolutions should form the pillars of an integrated approach in which modification of the electricity system and development of the infrastructure are seen together.

Such an approach requires several key policy goals.

5.1. Create a continuum among TSOs, DSOs and distributed generation

Address complex issues together

WHO: DSOs, TSOs, regulators
WHEN: Now

PV market development has shown how different PV is compared to traditional electricity sources:

- Time to market is extremely short in comparison with conventional power plants
- Scalability/modularity of PV makes it compatible with all voltage level connections
- Steep PV price decline over the last 30 years and low investment risk associated with PV increase investors' appetite
- A part of the market is driven by consumer choices, as opposed to the classical utility-led approach

For many years, regulatory authorities and system operators have underestimated potential PV deployment. In several countries' NREAPs, the objectives for 2020 have already been achieved. Underestimations of PV potential deployment by grid operators have led to costly retrofitting measures in some countries (the redefinition of frequency disconnection settings, for instance, and costly ad-hoc grid adjustment).

In order to attain a shared understanding of the evolution of the electricity mix at distribution level and of the technical capabilities of each technology, stakeholder forums at national or regional level should be regularly conveyed. This will allow network operators to transparently acquire state-of-the-art knowledge on forecast PV deployment and to make adequate investment decisions. In addition, best practices observed across Europe could be shared. The German VDE-FNN forum is a good example of such collaboration.

Improve DSOs and TSOs coordination in investment planning

WHO: DSOs, TSOs
WHEN: By 2013

Currently, communication between DSOs and TSOs is not always adequate. With increasing installed capacities in the distribution grid and with the subsequent take-up of new responsibilities by DSOs, coordinated planning of infrastructure investments should be implemented through formalised operational frameworks between TSOs and DSOs located in the same balancing area. Information should be exchanged on projects that have an impact on both levels of the network.

Use PV's capability to participate in system operation in the most cost-effective way

WHO: DSOs, TSOs, PV industry
WHEN: R&D already on-going. Deployment by 2017

As variable renewables become a larger part of Europe's energy mix, they will have to contribute further to system operation. Several R&D projects, such as REserviceS and metaPV, are already investigating how such contribution can be provided in cost-optimal ways.

Participation in system operation should be implemented considering that certain technologies are naturally placed to provide certain ancillary services at the best cost. PV generators should not bear responsibilities that could be handled by other generators at lower cost.

Create a European framework fostering harmonised national connection rules

WHO: Regulators, DSOs, TSOs
WHEN: Already on-going

System operation requirements will progressively be set by codes developed at European level, so as to ensure a homogenous approach across the continent. However, national regulators and network operators will still be left with important room for manoeuvre when implementing these codes on their territories.

Relevant European standards developed by ESOs should therefore properly be taken into account in national regulation when revising grid codes, especially in new markets, so as to avoid heterogeneity in the internal market. The EU standard for micro-generators and the technical guidelines for generators connected to the LV level should be considered as the most advanced description of inverter capabilities. Its pro-active use on a large scale will avoid potential costly retrofitting.

Unlock the potential of aggregation

WHO: Member States
WHEN: By 2016

Easy access to wholesale markets for PV electricity will be crucial to ensure revenues for small generators. In addition, DSOs will be confronted with an increasing number of distributed generators, with whom bi-directional communication will have to be ensured.

Aggregation will facilitate the participation of both decentralised production in electricity markets and the system operation. **A regulatory framework at national level should therefore be put in place Europe-wide**, so as to allow new or existing actors to provide aggregation services.

Identify the right functionalities for smart meters

WHO: CEN-CENELEC, PV industry
WHEN: Already on-going

The deployment of EVs, heat pumps, storage and smart household appliances will, together with the rise of distributed generation, multiply the amount of information to be treated at consumer level at each connection point. Standardised smart meters should be rolled out in order to integrate all these new devices at the lowest possible cost.

When defining **additional functionalities of smart meters**, ESOs should consider the ability to bi-directionally communicate on active/reactive power input/off-take; in addition, they should foresee the possibility for the DSOs to remotely control power flows. Future communication protocols should also remain open and should be established at European level so as to ensure compatibility across the EU.

5.2. Increase overall system flexibility

Adopt national strategies to increase overall system flexibility

WHO: Member States
WHEN: By 2015

With progressive penetration of variable RES in the electricity system, flexibility must be increased, while keeping system costs within acceptable boundaries. Existing measures to improve flexibility include: developing storage and DSM, increasing interconnections, improving forecasting, and promoting flexible generation.

EU Member States should **adopt by 2015 a roadmap identifying the best mix of measures to fully exploit their flexibility potential**. This strategy should take into account the ratio between the deployment cost and the degree of flexibility added by each of these measures to the electricity system. The roadmap should also envisage lifting identified market and regulatory barriers.

Assess storage potential in all Member States

WHO: Member States, European Commission
WHEN: By 2014

There is a perfect match between PV generation and daily storage, leading to efficient peak shaving.

National authorities should **assess by 2014 the potential for storage deployment** on their territory and communicate it to the European Commission. Optimal scale and technology (including cost evolution paths) of storage systems should be identified.

Enlarge balancing areas

WHO: TSOs
WHEN: By 2015

Today, balancing strategies implemented by TSOs remain nationally focused.

A real European vision of balancing should be developed so as to help integrate power produced by variable RES, especially PV. **Enlarging balancing areas by increasing the interconnection capacity** is a necessary measure to take. EU proposals to streamline permit granting procedures for the construction of transmission lines of European interest should therefore be implemented as a matter of priority.

Promote energy efficiency and demand side management

WHO: European Commission
WHEN: By 2015

Consumption peaks are one of the key factors determining network investments. Meeting peak consumption, especially in the evening, remains a challenge for variable RES, even under optimistic penetration assumptions.

In order to reduce overall system costs, measures shaving the peaks and reducing the base load should be put in place. DSM measures are appropriate to shave peaks, due to their load-shifting action. More generally, all energy efficiency measures contribute to reducing the base load. Hence, **an appropriate regulatory framework for energy efficiency and DSM should be further promoted at European level**.

Improve forecasting

WHO: TSOs
WHEN: By 2013

With the increasing contribution of PV to the electricity supply, predicting PV generation is becoming more and more important. Good forecasting enables increasing reliability and reduces overall costs by allowing a more efficient and secure management of electricity grids and solar energy trading.

Forecasting accuracy – also down to the local level – should therefore be improved. R&D should be implemented in order to design new tools. Aggregators could potentially help decrease the margin of error. Regional, national and EU wide cooperation between DSOs and TSOs will be required in order to better forecast production and to plan balancing needs.

5.3. Implement a new approach to overcome bottlenecks in the distribution grid

Improve the knowledge of the distribution network and better foresee its evolution

WHO: DSOs, regulators
WHEN: By 2013

The deployment of DER and of electric appliances such as EVs and heat pumps is changing DSOs' operations. Increasingly complex tasks will be added to DSOs' original role of distributing electricity to the consumers. These tasks should be undertaken at the lowest possible cost, while maintaining both power quality and system security. It is important that DSOs acquire or improve visibility on the current network status and forecast investment needs.

DSOs should constantly monitor and regularly assess the status of their grid, so as to identify current constraints and limits at the interface with TSOs. Advanced monitoring tools and standardised grid assessment methods should be used so as to obtain comparable results across Europe.

In addition, taking into account the input received from stakeholders, DSOs should run a prognosis exercise on the increasing share of DER installed capacities in their operation area. This will enable them to define forward-looking solutions. Where cost-effective, cooperation of DSOs operating in contiguous areas should be implemented.

Demonstration projects are also crucial to assessing the cost-effectiveness of all solutions to integrate DER in the electricity system. European policymakers should keep up their support for the implementation of such projects, notably to the ones in line with the priorities identified in the European Electricity Grid Initiative and the Solar Europe Industry Initiative.

Assess cost-effective distribution solutions

WHO: DSOs
WHEN: By the end of their current investment cycle

Grid extension and reinforcement is only one of the tools available to help overcome bottlenecks in the distribution network – and sometimes not the most cost-effective one. Before making investments that allow for higher accommodation of decentralised electricity production, **DSOs should undertake a cost-benefit analysis of all possible solutions, comparing grid extension and reinforcement with other available measures, including the exploitation of PV system capabilities**.

In order to fully integrate PV system capabilities into the network, **automation** of the MV network should be furthered. The possibility to control PV systems connected to the LV network should be investigated through R&D projects. Control at LV network should be then deployed only if it is proven to be cost-efficient in the wide context of the smart grids roll-out.

Increase visibility on DER

WHO: Regulators
WHEN: By 2013

In the wider context of ensuring improved knowledge of new distribution network needs, DSOs should in all EU Member States be aware of the presence of new DER, and in particular of PV systems, in their operation area.

Comprehensive information on PV installations should be reported to DSOs within a short delay. Systems on the MV network should be reported before production can start so as to maximise system stability. The information provided to DSOs should encompass all relevant features of the power plant – such as maximum power output, characteristics of the inverter – proportionately to the potential impact of the plant on the network.

These data should be aggregated and made available to the TSO in the operation area to which the DSO belongs. This will contribute to improving system operation.

Where relevant, regulators should update current national rules governing the information provided to DSOs.

Ensure the right to self-consume PV electricity

WHO: Member States
WHEN: Already on-going, should be extended

Self-consumption is a cost-effective instrument for relieving congestion in power networks. A large share of the electricity produced by PV power plants installed at – or close to – consumption points may be naturally self-consumed instantaneously, without being fed into the public grid.

Therefore increasing the share of self-consumption should be encouraged further. This can be done via various ways, including by financially incentivising self-consumption and by favouring DSM to shift demand and increase the correlation between daily load and production.

Member States should ensure that by 2014 a proper regulatory framework allowing for self-consumption is in place in their territories, in line with full electricity market liberalisation.

Set strict and transparent rules for contracted curtailment of PV electricity aimed at increasing hosting capacity

WHO: DSOs
WHEN: By 2020

Priority and guaranteed access and dispatch for electricity from RES as granted by the Renewable Energy Directive are important for integrating renewables in the internal electricity market. This priority should be maintained. **TSOs should be able to curtail PV electricity only in order to guarantee the security of the national electricity system and security of energy supply**.

In some limited cases, curtailment may be identified **at distribution level** to allow for a higher penetration of variable RES and to alleviate a temporary structural congestion issue. Such practices – departing from the Renewable Energy Directive, which aims at minimising the curtailment of renewable electricity – **should be proposed only as an option in the framework of a contract** between the DSO and the power generating unit owner, which should ensure a full compensation of the power generating unit owner. Such contracts should be based on transparent and non-discriminatory criteria, which should be pre-defined by the competent national authorities. The contract should also clearly foresee the maximum amount of electricity which could be curtailed per year.

Arbitrary limits, such as setting the AC/DC ratio below 100% (limiting de facto the power output of PV systems) should be abandoned in favour of smarter solutions.

5.4. Ensure a fair financing of all parties

Implement optimal approach for the provision of network services

WHO: Regulators, ENTSO-E, ACER
WHEN: By 2017

The contribution of PV to system operations will grow alongside its increasing share in the energy mix. The support provided by PV to system operation should be organised and remunerated in the most efficient way. **A combination of market-based mechanisms and technical requirements** in grid codes should be envisaged. The balance **should be the result of a cost-benefit analysis**, taking into account the potential impact of additional costs on PV competitiveness.

Valorise self-consumed electricity through proactive tariff settings

WHO: Regulators
WHEN: Now

As already shown, self-consumption will ease the management of the distribution grid. If smartly combined with storage devices, it can also participate in the reduction of peak load, thus reducing overall system costs.

Evolution of electricity tariffs should therefore recognise these advantages by **not exposing self-consumed electricity to grid costs and taxes**. In general terms, remuneration of network operators should be based on the amount of electricity effectively fed into the grid.

Ensure a proper remuneration of DSOs

WHO: Regulators
WHEN: By the end of DSOs current investment cycle

Increasingly complex tasks will be added to DSOs' original role of distributing electricity to the consumers.

Tariffs and their design – as set by national regulators – should ensure a fair rate of return for DSOs. This would allow them to take up new responsibilities and to make the needed investments. For example, the regulatory asset base to define tariffs should be enlarged to allow DSOs to invest in more innovative solutions.

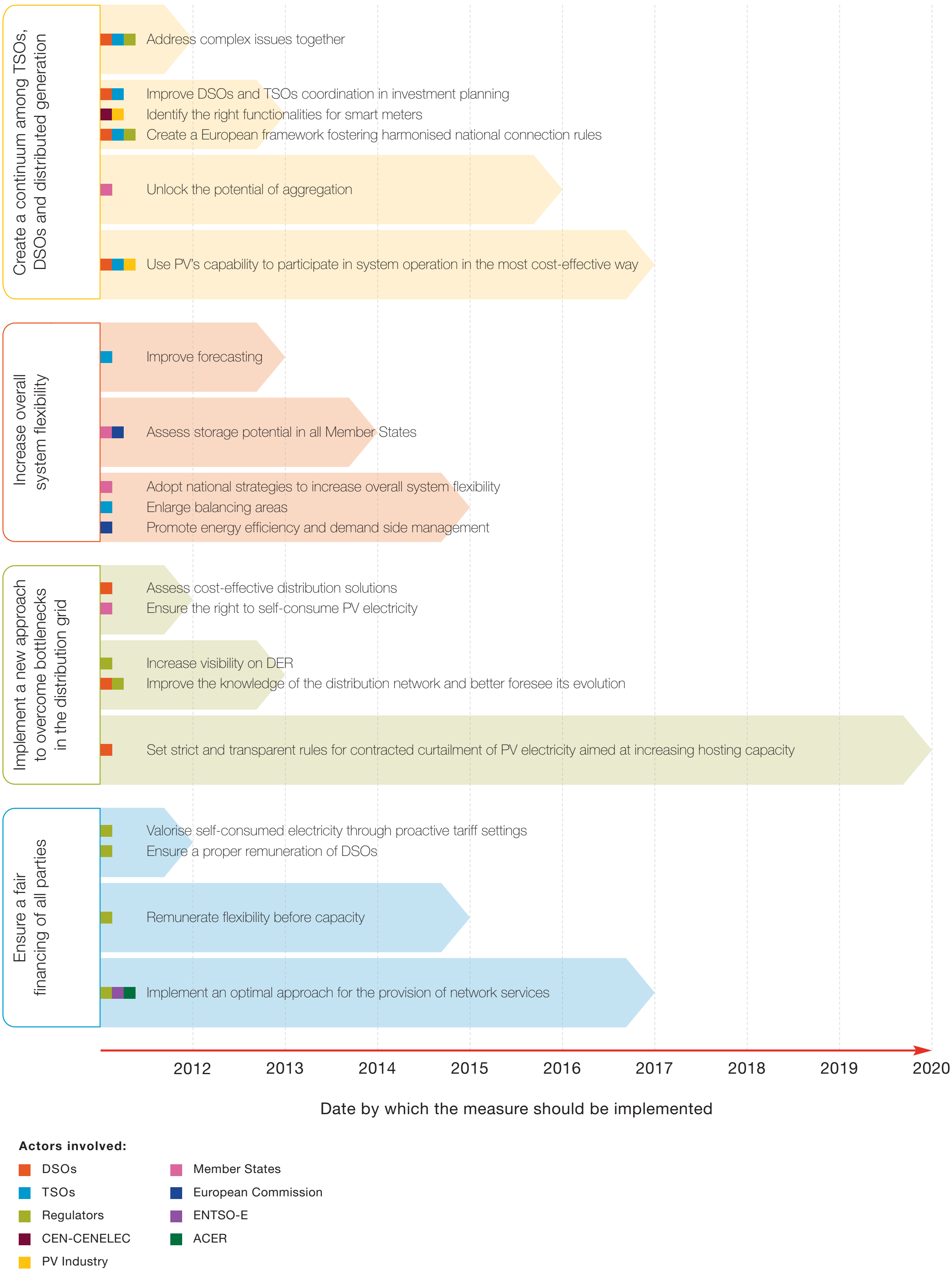
Remunerate flexibility before capacity

WHO: Regulators
WHEN: By 2015

With increasing penetration of variable RES in the electricity system, flexibility must be increased, while keeping system costs within acceptable boundaries.

This is why flexibility capabilities should be rewarded on the basis of a clear ranking among the various options, depending on local market conditions and marginal costs. Such remuneration should mirror the outcome of the national strategies to increase system flexibility, as devised by Member States. The remuneration of generation adequacy should be considered as the last resort measure.

Figure 53 - Policy recommendations - Actors involved and timeline



source: EPIA, 2012

ON THE ROAD TO LARGE-SCALE GRID INTEGRATION

The increasing role played by variable RES, including PV, in Europe's electricity system presents challenges for grid operators. However, in many ways, PV is already providing solutions – meeting a growing share of electricity demand at increasingly competitive cost without creating undue strain on the power system.

Even though it is not by nature dispatchable, PV electricity is decentralised and can be produced close to where it is consumed. Furthermore, it has a strong seasonal match with wind (since PV is able to meet more peak demand in summer, while wind is more productive in winter) and an average daily match (since PV produces during the day with a peak around midday, while wind produces more during less sunny hours); these two energy sources together can provide up to 45% of Europe's electricity needs in 2030. When viewed together (and when considered from a Europe-wide perspective rather than a local or national one), they provide realistic solutions to the technical challenges involved in integrating this large share of renewable electricity. In any case, these solutions are achievable, especially when combined with tools to increase the flexibility of the electricity system – such as storage and demand side management.

Europe's electricity demand is increasing. In the context of Europe's decarbonisation goals, this power will have to come from more variable RES. **As European policymakers consider their options for investments in new and more efficient grid infrastructure, they should take into account the benefits that PV is already producing and, more importantly, plan for the greater benefits it is capable of producing in the future.**

In that way, **PV can deliver on its promise as a major contributor to meeting Europe's energy, environmental and economic goals for the coming decades.**

All graphs and tables can be downloaded from **www.connectingthesun.eu**.

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ACRONYMS

AC	Alternating Current
CAES	Compressed Air Energy Storage
CCGT	Combined Cycle Gas Turbine
CSP	Concentrated Solar Power
DC	Direct Current
DER	Distributed Energy Resource
DG	Distributed Generation
DLR	Dynamic Line Rating
DSM	Demand Side Management
DSO	Distribution System Operator
DTR	Dynamic Thermal Rating
EHV	Extra-High Voltage
EMS	Energy Management System
ESOs	European Standard Organisations
EV	Electric Vehicle
FRT	Fault Ride-Through
GW – GWh	Gigawatt – Gigawatt-hour
HV	High Voltage
HVDC	High Voltage Direct Current
Hz	Hertz
kV - kVA - V	Kilovolt – Kilovolt-Ampere - Volt
kW – kWh	Kilowatt – Kilowatt-hour
LCOE	Levelised Cost of Electricity
LV	Low Voltage
MAE	Mean Absolute Error
MV	Medium Voltage
MW – MWh	Megawatt – Megawatt-hour
NMAE	Normalised Mean Absolute Error
NREAPs	National Renewable Energy Action Plans
NWP	Numerical Weather Prediction
OCGT	Open Cycle Gas Turbine
PHS	Pumped Hydroelectric storage
PV	Photovoltaic
R&D	Research & Development
RES	Renewable Energy Sources
RMSE	Root Mean Square Error
SLP	Standardised Load Profile
SME	Small and Medium Enterprises
SMES	Superconducting Magnetic Energy Storage
TSO	Transmission System Operator
TW – TWh	Terawatt – Terawatt-hour
V2G	Vehicle to Grid
VPP	Virtual Power Plant
VRB	Vanadium Redox Batteries
VRE	Variable Renewable Energy
W – Wh	Watt – Watt-hour
WACC	Weighted Average Cost of Capital

GLOSSARY

Ancillary services: Services required to secure the supply of electricity to the end customer and maintain system's reliability.

Balancing study: Describes the simulation study presented in Chapter 2, where the electricity demand is compared with VRE generation and the effect on the residual load is presented.

Black start: Start-up of generation without the need of power from the grid.

Dispatchable generators: Generators that can dispatch power upon request of the network operators. Dispatchable generators are flexible generators that can reduce or increase the output on demand.

Distributed Generation: Generators that can provide electricity close to the consumer. They are normally of small scale (decentralised generation) and connected to the distribution network.

Distribution grid: Comprises LV, MV and, in some countries, HV networks.

Fault Ride-Through (or LV ride-through): Technical requirement for electrical devices (e.g. PV systems) in some countries. Describes the capability of those devices to act accordingly when the voltage in the grid is temporarily reduced due to a fault. Depending on the duration and magnitude of the fault, the generator might be required to stay connected and inject reactive power during the fault or disconnect.

Feeder: MV power line that transfers power from a distribution substation to the distribution transformers.

Frequency: Number of times the flow direction changes (back and forth) per second in an AC circuit. It is measured in Hertz (Hz).

Load (or demand): Amount of electricity used at any given moment in time.

Load duration curve: Shows for how long the load exceeds or is equal to a given load value over a specific period of time (usually a year).

Low Voltage (LV), Medium Voltage (MV), High Voltage HV), Extra-High Voltage (EHV) (typical ranges): LV: ≤1kVa, MV: 1kVa<voltage≤38kVa, HV: 38kVa≤voltage≤230kVa, EHV: ≥230kVa.

Peak: Hours during a period of time (normally a day) when demand is at its highest.

Peak load (or peak demand): Maximum demand for electricity in a given period of time.

Power quality: Set of limits defined by standards for voltage, current and/or frequency disturbances.

Power ramping: Gradual sequence of changes in power output.

Reactive power: Circulating power in the AC grid that does not do useful work. Part of the apparent power flow that results from energy storage elements (inductive-magnetic field storage or capacitive-electrical field storage) and then returns to source. Has a strong effect on the system's voltage level and is needed to support the transfer of the active power over the network.

Reserves: Generation capacity that is available, if needed, to the system operator but is not constantly generating electricity.

Residual load: Load minus the PV and wind generation.

Scheduling: Planning process of determining which generators will be used to generate constantly electricity or will be used as reserves at a specific time. It also determines which power flows will be allocated to each transmission line.

Self-consumption: Possibility for any kind of electricity producer to directly use/consume part or all of the electricity produced at the same location (on-site consumption), instantaneously.

Transformer: Device that transfers electrical energy from one circuit to another through magnetically coupled conductors.

Transmission grid: Part of the power system that involves the HV and EHV network.

Voltage: Potential difference in charge between two points in an electrical field. The greater this potential the greater the flow of electrical current through a medium for a given resistance to the flow.

ANNEX A
COMPETITIVENESS ANALYSIS

A.1. Competitiveness – two perspectives: prosumers and utilities

When considering the competitiveness of PV versus other electricity sources, two specific situations should be considered:

- Residential, commercial and industrial segments – the local consumption of PV electricity: The electricity consumer invests in a PV system that will provide a part of its electricity needs; it goes from being a consumer to a "prosumer". The size of the system does not matter as long as a part of the electricity produced is locally consumed. Hence, residential, commercial and industrial applications are taken into consideration. In this case, competitiveness of PV is defined as **"dynamic grid parity"**. Assessing dynamic grid parity requires determining the moment at which it becomes equally or more cost-efficient to install a PV system than to buy all electricity from the grid. In other words: PV will reach dynamic grid parity when the electricity produced by the PV system throughout its lifetime is at least as profitable as buying electricity on the grid – now and in the future
- Industrial and ground-mounted segments – the generation of PV electricity for grid injection: PV is increasingly being integrated into power generation portfolios of power utilities and independent power producers as a new source of electricity production. Given the current peak-load generation profile of PV (producing mainly during mid-day peak when gas turbines are usually running), its competitiveness will be assessed by comparing it to a standard Combined Cycle Gas Turbine (CCGT) power plant. In this case, competitiveness of PV is defined as **"generation value competitiveness"**. In other words: PV will reach competitiveness as a power generation source when, from a financial point of view, its generation cost (the Levelised Cost of Electricity, or LCOE) is at or below the level of a new CCGT plant. The **"wholesale competitiveness"** is the moment at which the LCOE of PV becomes lower than the average wholesale price of electricity at the moments during which PV produces

"Dynamic grid parity" is defined as the moment at which, in a particular market segment in a specific country, the present value of the long-term net earnings (considering revenues, savings, cost and depreciation) of the electricity supply from a PV installation is equal to the long-term cost of receiving traditionally produced and supplied power over the grid.

"Generation value competitiveness" is defined as the moment at which, in a specific country, adding PV to the generation portfolio becomes equally attractive from an investor's point of view to investing in a traditional and normally fossil-fuel based technology.

"Wholesale competitiveness" is defined as the moment at which – in a particular segment in a country – the present value of the long-term cost of installing, financing, operating and maintaining a PV system becomes lower than the price of electricity on the wholesale market.

A.2. Updating parameters

Compared to the study “Solar Photovoltaics Competing in the Energy Sector: On the road to competitiveness”, published in September 2011, this new study assesses competitiveness with a new range of parameters that are more in line with the rapid evolution of system prices but also the global economic environment. These parameters are briefly explained here.

Table 4 - Comparison of the values used for the PV competitiveness analysis

	September 2011	September 2012
Current module and system prices	Q4-2010 / Q1-2011	Q2-2012
Irradiation levels	Average	Low, average and high
Electricity prices	2010	2011
Administrative costs	PV Legal intermediary data	PV Legal final data
Module and inverter prices evolution	One average scenario per market segment	Two scenarios per market segment based on current prices ranges and evolution hypothesis
Cost of capital	Low WACC	Two scenarios based on low WACC with or without a risk premium

source: EPIA, 2011 and 2012

Systems prices indicated in this study (Figure 3) do not always reflect the market reality. In several countries, the price of PV systems remains higher than the targeted value used in this study. Non-mature markets explain these differences but the convergence will most probably occur in the next two years, under pressure of the lower incentives. One can argue lower prices can be found on the European market at the time of this study’s publication. Nevertheless this analysis does not consider the lowest prices available. The goal remains to assess how competitiveness can be reached for most actors; for that reason, the analysis considers reasonably low prices that are representative of today’s production costs.

Given the current financial difficulties in several European countries, the hypothesis made in “Solar Photovoltaics Competing in the Energy Sector: On the road to competitiveness” is no longer valid. The low cost of capital that corresponds to the real risk level of mature PV investments should be placed alongside risks associated to emerging actors who do not always possess enough quality experience. As a result, this report considers a range for the WACC: September 2011 data were kept as a lower boundary while the high boundary is defined for all countries assessed.

Table 5 - Comparison of the values used for the WACC

Segment	Low WACC (without risk premium)	High WACC (with risk premium)
Residential	4.4%-6.1%	7%
Commercial-industrial	6.5%-8.2%	9%
Utility-scale	6.5%-8.2%	11%

source: EPIA, 2012

A.3. Delays and anticipations of competitiveness in Europe

Three main sets of impacts were assessed with regard to the EPIA study published in September 2011:

- **What is the impact of the fast price decline in PV systems in 2011 and early 2012 on competitiveness on the short and medium term?** Also, over the long term, how could the prospect for PV system price evolution take into account the current price decrease and what could be the impact on competitiveness?
- **What impact will the financial crisis in Europe have on the cost of capital of PV projects?** Could it delay significantly the competitiveness if the expected decrease in cost of capital is not achieved in the coming years?
- **What impact will the differences in solar irradiation from north to south within a country have on the range of competitiveness dates in all large countries?**

A.3.1. Impact of PV system prices decrease

- **The current price evolution has brought competitiveness forward in the residential segment** by one to three years, except in the UK, where competitiveness was expected to be reached in 2019. Depending on the price evolution, France and Germany could reach competitiveness between 2014 and 2015, while Italy has virtually reached it in the centre of the country or will reach it in 2013 if prices stagnate. In Spain, 2015 or 2016 are the target dates
- **In the commercial segment, the effect is at least as impressive**, with competitiveness reached in 2012/2013 in Italy and Spain. Even France and UK could reach that level of competitiveness in between 2015 and 2017, depending on price evolution
- In the **industrial segment**, competitiveness may be delayed in Spain, due to revised data on administrative costs, while **most countries are expected to reach competitiveness between 2018 and 2020**. The only exception is Italy, where high electricity prices make it possible in 2012 already, even with a slow evolution of PV system prices
- **For utility-scale PV systems, there is little change from the results expected in September 2011**, if a comparison is done with a CCGT power plant. Wholesale competitiveness is expected, mostly around 2020, except in Italy and France. Reaching competitiveness on the wholesale market will imply favourable conditions. With the decrease of PV system costs, the cost of operation and maintenance will grow in relation with the LCOE.

A.3.2. Impact on cost of capital

- **Among all drivers, the cost of capital has the most impact on competitiveness**. The current high cost of capital in some countries and segments could delay competitiveness by two to four years compared to the same assessment done with a reasonably low cost of capital. This is particularly significant for utility-scale installations when compared to the wholesale price of electricity: In that case, more than 10 years will be necessary, except in Italy (2019), to reach competitiveness in that segment with a cost of capital increased to 11%

A.3.3. North and south differences within countries

All assessments were done using an average irradiation value per country. But assuming that most countries have a wide range of irradiation, this could lead some parts of a particular country to be competitive before the average while other regions could require much longer. In Europe there is a standard range that can reach up to seven years.

- In the **residential segment**, northern France will reach competitiveness in 2019, seven years after the south; it will happen six years later in northern Spain (2019) than in the south (2013) and five years later in the north of the UK compared to the south. In Italy and Germany, there is only three years' difference
- In the **commercial and industrial segment**, such differences are shown as well: in the commercial segment, **while most countries could expect competitiveness already in 2012 or 2013 in the south, the north will have to wait until the end of the decade**. This is even more pronounced with France, UK and Spain reaching it not before 2023. In the north of Italy, it could be reached at the end of 2013
- Competitiveness in the **utility-scale segment** in the north of the countries assessed could take until 2020 while in their southern parts generation value competitiveness could be reached in 2012/2013 except in UK and Germany. Wholesale competitiveness could be delayed until 2018 in Germany, Spain and UK

Table 6 - Impact of prices, cost of capital and irradiation level on PV competitiveness

Competitiveness type	Market segment	Country	EPIA September 2011	EPIA September 2012: Impact of system price decrease • Low prices • Low WACC • Average irradiation	• High prices • Low WACC • Average irradiation	Impact of cost of capital • Low prices • High WACC • Average irradiation	• High prices • High WACC • Average irradiation	Impact of north/south difference inside a country • Low prices • Low WACC • HIgh irradiation	• High prices • Low WACC • Low irradiation
Dynamic grid parity	Residential	France	2016	2014	2015	2017	2019	2012	2019
		Germany	2017	2014	2015	2017	2018	2013	2016
		Italy	2015	2012	2013	2015	2017	2012	2015
		Spain	2017	2015	2016	2018	2020	2013	2019
		United Kingdom	2019	2017	2019	2021	after 2022	2016	2021
	Commercial	France	2018	2015	2016	2018	2019	2013	2020
		Germany	2017	2013	2014	2015	2017	2012	2015
		Italy	2013	2012	2012	2012	2012	2012	2012
		Spain	2014	2012	2013	2014	2015	2012	2016
		United Kingdom	2017	2015	2017	2018	2020	2014	2019
	Industrial	France	2019	2018	2019	2021	after 2022	2015	after 2022
		Germany	2019	2015	2017	2018	2020	2014	2018
		Italy	2014	2012	a2012	2012	2014	2012	2013
		Spain	2017	2018	2020	2022	after 2022	2015	after 2022
		United Kingdom	2019	2019	2020	2022	after 2022	2017	after 2022
Generation value competitiveness	Industrial	France	2015	2014	2015	2016	2018	2012	2020
		Germany	2017	2016	2017	2018	2021	2014	2019
		Italy	2016	2013	2014	2015	2016	2012	2016
		Spain	2015	2015	2016	2017	2020	2012	2021
		United Kingdom	2019	2019	2021	after 2022	after 2022	2017	after 2022
	Ground-mounted	France	2015	2014	2015	2016	2017	2012	2019
		Germany	2017	2016	2017	2019	2021	2015	2019
		Italy	2014	2015	2015	2017	2018	2013	2017
		Spain	2015	2014	2015	2016	2017	2012	2019
		United Kingdom	2019	2019	2021	after 2022	after 2022	2017	after 2022
Wholesale competitiveness	Ground-mounted	France	N/A	2016	2017	2019	2020	2014	2021
		Germany	N/A	2019	2020	2022	after 2022	2018	2021
		Italy	N/A	2016	2017	2019	2020	2015	2019
		Spain	N/A	2021	2022	2022	after 2022	2018	after 2022
		United Kingdom	N/A	2020	2021	after 2022	after 2022	2018	after 2022

source: EPIA, 2011 and 2012

ANNEX B
PV AND WIND DEPLOYMENT SCENARIOS UNTIL 2030

Table 7 - PV cumulative capacity scenarios until 2030 (MW)

Country	Global Market Outlook 2012	Accelerated scenario 2020 (8% PV penetration)	Accelerated scenario 2030 (15% PV penetration)	Paradigm Shift scenario 2030 (25% PV penetration)
Austria	176	4,000	10,000	15,000
Belgium	2,018	7,000	13,000	26,000
Bulgaria	135	3,000	6,500	9,000
Cyprus	9	300	800	1,000
Czech Republic	1,959	4,000	9,000	18,000
Denmark	16	1,000	2,500	5,000
Estonia	0.2	400	800	2,000
Finland	1	1,000	2,000	8,000
France	2,659	30,000	70,000	125,000
Germany	24,678	65,000	100,000	150,000
Greece	631	8,000	16,000	20,000
Hungary	4	2,000	5,000	8,000
Ireland	3	400	2,000	4,000
Italy	12,754	42,000	65,000	97,000
Latvia	0.2	400	800	2,000
Lithuania	0.3	400	1,000	2,000
Luxembourg	30	400	1,000	2,000
Malta	12	250	400	500
Netherlands	103	3,000	15,000	32,000
Poland	3	5,000	20,000	40,000
Portugal	183	3,000	8,000	13,000
Romania	3	5,000	10,000	16,000
Slovakia	468	3,000	6,000	10,000
Slovenia	81	1,500	3,000	5,000
Spain	4,400	18,000	45,000	76,000
Sweden	15	1,000	6,000	12,000
United Kingdom	875	20,000	40,000	70,000
Total EU 27	**51,216**	**229,050**	**458,800**	**768,500**

source: EPIA, 2011 and 2012

Table 8 - Wind cumulative capacity scenarios until 2030 (MW)

Country	Onshore			Offshore		
	2011	2020	2030	2011	2020	2030
Austria	1,100	3,500	4,300	-	-	-
Belgium	354	2,100	2,500	360	1,960	3,760
Bulgaria	700	3,000	3,550	-	20	40
Cyprus	82	300	450	-	-	50
Czech Republic	300	1,600	1,920	-	-	-
Denmark	2,771	3,820	4,280	903	2,581	3,651
Estonia	170	500	1,200	-	-	1,600
Finland	200	1,500	2,360	30	600	3,200
France	5,204	18,990	37,999	-	2,510	5,260
Germany	28,871	41,000	47,000	108	10,223	39,043
Greece	1,700	6,500	12,000	-	-	200
Hungary	400	900	1,600	-	-	-
Ireland	977	5,000	5,400	25	1,055	3,880
Italy	5,785	15,770	19,090	-	500	1,400
Latvia	27	200	500	-	-	900
Lithuania	54	1,000	1,570	-	-	1,000
Luxembourg	150	300	700	-	-	-
Malta		100	200	-	-	-
Netherlands	1,970	5,000	6,000	240	4,775	10,775
Poland	1,700	11,000	16,000	-	500	5,800
Portugal	4,083	7,572	9,412	-	-	200
Romania	10	3,000	3,900	-	20	40
Slovakia	3	800	1,100	-	-	-
Slovenia		500	860	-	-	-
Spain	16,740	39,000	47,666	-	1,100	1,700
Sweden	888	5,990	7,000	130	2,978	10,516
United Kingdom	4,726	13,000	19,360	2,656	15,306	38,149
Total EU 27	78,965	191,942	257,917	4,452	44,128	131,164

source: OffshoreGrid project, EWEA, 2011

ANNEX C
ASSESSING THE BALANCING LIMITS IN EUROPE: ASSUMPTIONS & METHODOLOGY

C.1. Assumptions

C.1.1. PV capacity scenarios

Scenarios for installed PV capacity in 2020 and 2030 for the EU 27 countries follow the revised, intermediate "Accelerated" scenario. This scenario targets 8% penetration of PV in 2020 in the Europe (EU 27+ NO, CH and TR) and 15% in 2030 (table 7).

A "Baseline" scenario targeting 4% in 2020 and 10% in 2030 was not directly assessed since the conclusions of higher scenarios remain valid.

C.1.2. Wind capacity scenarios

The scenarios for the capacity of onshore and offshore wind power in the EU 27 countries by 2020 and 2030 are based on scenarios from the European Wind Energy Association (EWEA) in conjunction with policy goals of national governments and wind farm planning of project developers.

The scenario chosen for wind power by 2030 targets 30% penetration (table 8). It is driven by ongoing and future market planning and political initiatives at national and European level. After 2020, plans for a high share of offshore wind are considered.

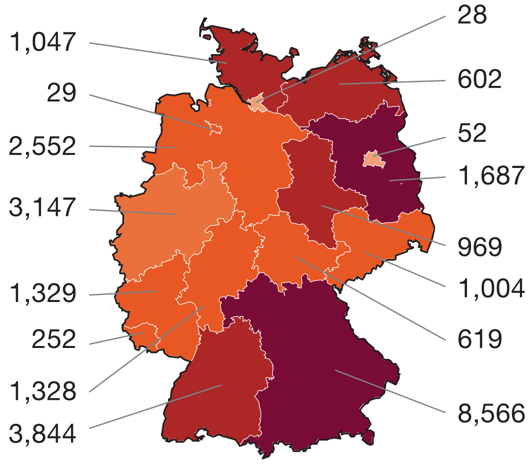
C.1.3. Capacity distribution per country and region until 2030

In Annex B the breakdown of the total PV and wind capacity is presented for each of the EU 27 countries until 2030. Normally in a country, wind resources are often higher near the coast and in the north, while the highest irradiation levels are reached in the south. This resource distribution was taken into account to estimate future PV and wind capacities distribution per region and per country. An algorithm was used to spread the national capacities to regions with weighting factors applied to all regions according to their PV and wind potential based on the irradiation level (table 9) and/or the electrical consumption (table 11). Those regional weighting factors (and not the capacity itself) were assumed to remain the same between 2020 and 2030. These did not take into account the effect of support schemes on the current distribution of systems across the country. In key countries most recent available data on regional distribution were used. Figure 54 shows the example of Germany.

For the distribution of offshore wind, new regions were assumed at the coastal area and the exclusive economic zones. These regions were chosen in line with the wind farm planning of project developers. For instance in the case of Germany eight different offshore regions where created.

The capacity for each of these offshore regions was then determined for the years 2012, 2020 and 2030. For this, the different offshore development goals of the different countries were taken into account as studied in the project OffshoreGrid. This resulted in a highly accurate site-specific distribution of offshore wind farms over time.

Figure 54 - PV capacity in Germany by region at the end of 2011 (MW)



source: EPIA, 2011

Table 9 - PV output per kW at optimal angle in urban areas (kWh/year)

Country	Minimum	Average	Maximum
Austria	853.6	1,026.9	1,169.6
Belgium	866	929.6	1,007.6
Bulgaria	1,005.9	1,217.8	1,388.4
Cyprus	1,563.6	1,629.8	1,683.1
Czech Republic	838.6	945.6	1,039.7
Denmark	841.2	945.1	1,054.1
Estonia	813.5	867.7	898.8
Finland	765.3	837.9	895.5
France	858	1,116.7	1,515.3
Germany	825.5	936	1,085.8
Greece	1,200	1,445	1,667
Hungary	991.6	1,104.7	1,159.2
Ireland	789.5	908.6	1,066.7
Italy	772.9	1,326	1,624
Latvia	817.8	890.2	992.6
Lithuania	824.5	884.4	1,011
Luxembourg	900.3	939.6	967.5
Malta	1,572.1	1,584.2	1,599.2
Netherlands	864.7	932.6	1,020.7
Poland	833.6	937.2	979.7
Portugal	1,270.7	1,494	1,648.6
Romania	891.1	1,132.7	1,278.3
Slovakia	845.5	1,020.7	1,116.8
Slovenia	931.6	1,085.2	1,249.7
Spain	968.2	1,470.7	1,664
Sweden	639.1	826	1,050.8
United Kingdom	710.8	920.2	1,121

source: JRC, 2012

Table 10 - Average EU wind full load hours until 2030 (kWh/year)

Full load hours	Offshore	Onshore
2011	3,500	1,738
2020/2030	3,700	2,100

source: OffshoreGrid project, EWEA, 2011

Table 11 - Final electricity demand until 2030 (TWh)

Country	2010	2015	2020	2025	2030
Austria	57	60	62	68	71
Belgium	81	87	93	101	106
Bulgaria	26	28	30	32	34
Czech Republic	58	64	70	75	79
Denmark	34	35	35	37	39
Estonia	6	7	8	8	9
Finland	85	89	90	91	91
France	421	459	482	519	550
Germany	528	553	556	571	581
Greece	54	60	65	71	76
Hungary	33	36	38	41	43
Ireland	25	28	30	33	35
Italy	300	324	345	365	378
Latvia	6	7	7	8	9
Lithuania	8	9	10	11	11
Luxembourg	7	8	8	9	9
Netherlands	106	114	118	121	123
Poland	115	126	139	151	165
Portugal	46	49	52	56	59
Romania	41	46	51	57	60
Slovakia	25	29	33	36	38
Slovenia	13	14	16	17	17
Spain	246	275	297	325	344
Sweden	131	136	139	144	143
United Kingdom	340	356	365	380	387

source: ENTSO-E, 2011

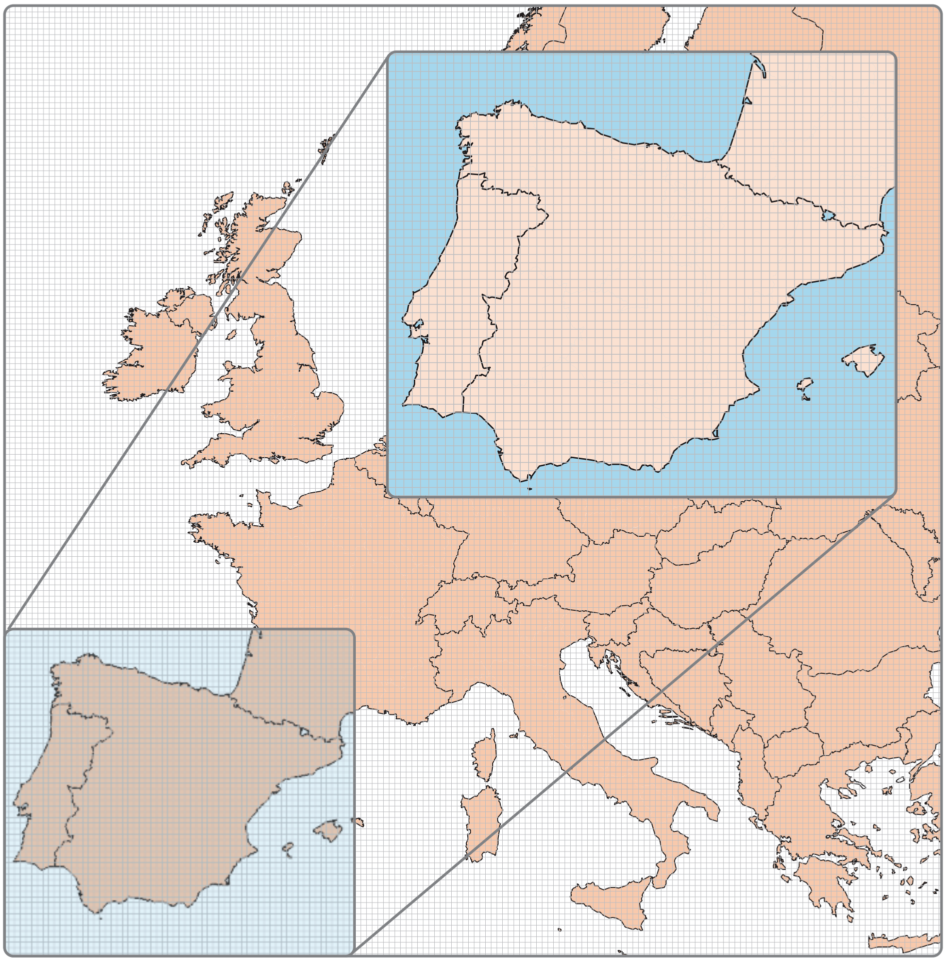
C.2. Methodology

C.2.1. Mesoscale model

The fact that across Europe characteristics such as weather and terrain are not uniform creates a highly complex situation for obtaining useful information per region and per site. To address this heterogeneous fact and obtain representative data on PV and wind power across a region, numerical methods using a high-resolution grid were used (Figure 55).

Time series of wind speed, solar irradiation and temperature were created first by using the mesoscale model in order to produce time series for power generation. This simulation resulted in wind and irradiation time series for grid points spaced by 14km covering the whole of Europe. The weather year chosen was 2010 and the time resolution was 1 hour. The simulation was carried out for a full year. A latitude-longitude grid with horizontal resolution of 14km and 28 vertical levels was applied.

Figure 55 - Mesoscale grid covering Europe



source: EPIA, 2012

C.2.2. PV and wind production series

Based on the time series generated, and based on the capacities assigned by regions, time series of electricity production by wind and PV were created.

For the PV generation, standard modules and inverter models were applied. It was assumed that all modules are directed south with an optimal inclination angle, therefore the annual electricity generation might slightly differ from the "real" one. The PV time series were adjusted based on the average PV output by kW provided by JRC as shown in table 9.

Wind power generation was generated based on wind turbine power curves taken from the TradeWind study, differentiating onshore and offshore wind parks, and predicting future evolutions until 2030. The wind time series were adjusted based on measured data from past years (installed capacity and the associated generation). For 2020 and 2030 it was assumed that the full hours for wind increase due to repowering, more efficient turbines and blades of newly installed wind farms. A distinction was made between offshore and onshore full load hours (table 10).

C.2.3. Demand profiles

The hourly load values of all European countries were taken from the ENTSO-E online data-base, providing complete data up to 2011 in hourly resolution per country. For 2020 and 2030, the 2011 profile is up-scaled to the demand that is expected by the reference scenario as found in "EU Energy Trends to 2030" (2009 update).

C.3. Limitations

In order to envision in the best possible way the electricity system in 2020 and 2030 in Europe, the scenarios consider high penetrations of PV and wind and focus only on the effect that those VRE have on the power system. That approach includes some limitations:

- Dispatchable renewables such as hydro, biomass and geothermal were not considered in the simulation procedure. Those "must-run" technologies that are given priority dispatch will of course play a significant role in the future electricity mix, increasing the total capacity credit of renewables in Europe. Co-generation units or micro CHPs are also part of such technologies but were not considered as well.
- CSP technologies were assumed to be developed with storage features and it was considered that they will not represent a major part of the European electricity mix even in 2030

ANNEX D
DIFFERENT FORECAST ERRORS

How to read the forecast errors

When comparing forecast accuracies it is important to make sure that the same error formula and error normalisation is applied and that the error is applied to the same system or portfolio size in the same geographical region. The most important aspects of error measures are:

- Error types: The two most common error types for RES generation forecasts are the Root Mean Square Error (RMSE) and the Mean Absolute Error (MAE). The RMSE is always larger than the MAE for the same forecast accuracy. That depends also on whether one takes into account night time or not
- Transformation: It is not possible to simply translate one error measure into another without inaccuracies. To determine the exact error for the forecast and actual production, time series are needed
- Normalisation: Errors are almost always normalised in order to give percentages and justify the comparison of errors for different system or portfolio sizes: Normalised MAE (NMAE) or Normalised RSME. Comparison is only possible when the normalisation is applied. In most cases the error is normalised to peak power or average production. The difference between these two amounts already to a factor four
- Night time considerations: PV forecast errors are calculated sometimes for day-time values only. Most error measures (except NMAE) change depending on whether the forecast also takes night time values into account
- System location: For some locations the forecasting is easier and thus more accurate than for others. The forecast error therefore strongly depends on where the system is located
- Weather conditions: In some locations, weather is much more variable and harder to predict
- System/portfolio size: The forecast error depends on the system sizes, of the number of systems within a portfolio and its regional spread

ANNEX E
PV REGIONAL DEPLOYMENT SCENARIOS FOR 2030

Table 12 - 2030 European PV capacity scenarios (MW)

Country	Irradiation-driven scenario	Current spatial distribution scenario	Consumption-driven scenario
AUSTRIA	7,726	10,000	10,000
BELGIUM			
Bruxelles/Brussels	12	47	1,024
Vlaanderen	975	11,578	7,903
Wallonie	1,225	1,375	4,042
BULGARIA	10,166	6,500	6,500
CYPRUS	2,768	800	800
CZECH REPUBLIC			
Hlavní mesto Praha	35	69	2,803
Jihoceský	956	1,078	292
Jihomoravský	940	2,044	535
Karlovarský	62	61	254
Královéhradecký	455	341	230
Liberecký	59	489	257
Moravskoslezský	388	222	1,239
Olomoucký	498	495	273
Pardubický	432	395	322
Plzenský	547	896	355
Stredoceský	784	1,072	818
Ústecký	210	772	1,138
Vysocina	481	357	275
Zlínský	371	710	314
DENMARK	3,141	2,500	2,500
ESTONIA	880	800	800
FINLAND	3,049	2,000	2,000
FRANCE			
Alsace	1,082	2,509	2,408
Aquitaine	3,777	7,306	3,115
Auvergne	2,546	2,150	1,318
Basse-Normandie	1,632	800	1,693
Bourgogne	3,866	1,186	1,729
Bretagne	4,362	3,033	3,275
Centre	4,793	1,709	2,708
Champagne-Ardenne	3,314	1,737	1,668
Corse	1,359	1,627	192
Franche-Comté	1,983	662	1,315
Haute-Normandie	1,154	855	2,736
Ile-de-France	1,114	1,516	17,398
Languedoc-Roussillon	5,331	6,837	2,062
Limousin	2,074	1,020	700
Lorraine	2,163	1,847	3,214
Midi-Pyrénées	9,392	7,830	2,330
Nord-Pas-de-Calais	1,182	1,296	6,047
Pays de la Loire	3,139	5,762	3,621
Picardie	1,817	993	2,360
Poitou-Charentes	2,360	3,722	1,586
Provence-Alpes-Côte d'Azur	5,770	10,091	4,574
Rhône-Alpes	4,239	5,514	8,637
GERMANY			
Baden-Württemberg	3,284	14,482	12,397
Bayern	6,544	32,626	14,624
Berlin	65	184	2,522
Brandenburg	2,115	6,253	2,801
Bremen	6	102	973
Hamburg	30	91	2,263
Hessen	834	4,883	7,089
Mecklenburg-Vorpommern	1,695	2,103	1,231
Niedersachsen	3,468	9,237	10,099
Nordrhein-Westfalen	1,347	11,374	29,286
Rheinland-Pfalz	786	4,752	5,107
Saarland	181	902	1,672
Sachsen	1,321	3,591	3,517
Sachsen-Anhalt	1,458	3,462	2,583
Schleswig-Holstein	616	3,856	2,161
Thüringen	1,160	2,101	7,857
GREECE	20,600	16,000	16,000
HUNGARY	11,440	5,000	5,000

Country	Irradiation-driven scenario	Current spatial distribution scenario	Consumption-driven scenario
IRELAND	1,305	2,000	2,000
ITALY			
Abruzzo	2,006	2,295	1,283
Basilicata	1,991	1,128	581
Campania	2,128	1,895	3,432
Emilia Romagna	4,541	6,453	5,995
Friuli Venezia Giulia	717	1,502	2,256
Lazio	2,699	4,413	4,573
Liguria	1,096	271	1,438
Lombardia	4,827	6,714	14,461
Marche	1,852	4,004	1,585
Molise	877	595	303
Piemonte	4,984	5,461	5,415
Puglia	3,533	11,137	3,470
Sardegna	7,680	2,052	2,068
Sicilia	8,305	4,382	3,579
Toscana	4,580	2,383	4,380
Trentino Alto Adige	1,214	1,514	1,490
Umbria	1,623	1,623	1,161
Valle d'Aosta	298	69	221
Veneto	3,751	5,909	6,580
LATVIA	1,225	800	800
LITHUANIA	1,247	1,000	1,000
LUXEMBOURG	101	1,000	1,000
MALTA	97	400	400
NETHERLANDS	1,631	15,000	15,000
NORWAY	3,638	2,000	2,000
POLAND	12,221	20,000	20,000
PORTUGAL	13,918	8,000	8,000
ROMANIA	23,472	10,000	10,000
SLOVAKIA	4,544	6,000	6,000
SLOVENIA	2,539	3,000	3,000
SPAIN			
Andalucia	27,461	8,405	6,410
Aragon	7,223	1,493	1,777
Asturias	1,334	10	2,584
Baleares	751	675	1,016
Calabria	2,329	1,201	1,076
Canarias	2,374	1,411	1,518
Cantabria	657	20	1,153
Castilla la Mancha	24,845	9,437	2,103
Castilla y Leon	14,655	4,775	2,628
Catalunya	4,828	2,393	8,739
Ceuta y Melilla	10	1	72
Comunidad Valenciana	7,194	3,200	4,556
Extremadura	13,360	5,705	797
Galicia	6,029	123	4,228
La Rioja	1,491	910	279
Madrid	2,527	491	5,200
Murcia	3,561	4,131	1,355
Navarra	1,994	1,585	998
Pais Vasco	870	235	4,792
SWEDEN	8,813	6,000	6,000
SWITZERLAND	5,009	9,000	9,000
TURKEY	36,167	35,000	35,000
UNITED KINGDOM			
East Midlands	611	3,697	2,913
East of England	1,394	4,421	3,721
Greater London	111	944	5,507
North East	626	1,067	1,654
North West	1,033	2,690	4,540
Northern Ireland	545	3	1,099
Scotland	779	3,532	4,639
South East	1,754	6,528	4,998
South West	1,701	7,675	3,335
Wales	1,491	2,529	2,121
West Midlands	509	2,743	3,430
Yorkshire and the Humber	289	4,170	3,529
TOTAL EUROPE*	**470,528**	**504,801**	**522,782**

source: EPIA, 2012
***:** Europe includes here the EU 27, Turkey, Norway and Switzerland

ANNEX F
IMPACT OF GRID INTEGRATION ON PV COMPETIVENESS

Table 13 - Impact of curtailment and exposure to grid costs and taxes on competitiveness

Competitiveness type	Market segment	Country	• Low prices • Low WACC • Average irradiation	• 10% curtailment	• Exposure to grid costs	• Exposure to taxes	• Exposure to grid costs and taxes
Dynamic grid parity	Residential	France	2014	2015	2016	2018	2020
		Germany	2014	2015	2015	2019	2020
		Italy	2012	2013	2014	2015	2017
		Spain	2015	2016	2016	2018	2019
		United Kingdom	2017	2019	2019	2018	2020
	Commercial	France	2015	2016	2021	2017	after 2022
		Germany	2013	2014	2016	2019	2022
		Italy	2012	2012	2012	2013	2013
		Spain	2012	2013	2020	2014	2022
		United Kingdom	2015	2017	2019	2015	2019
	Industrial	France	2018	2019	2020	2021	after 2022
		Germany	2015	2017	2017	2021	after 2022
		Italy	2012	2012	2012	2016	2016
		Spain	2018	2020	2021	2020	after 2022
		United Kingdom	2019	2021	2021	2020	2022
Generation value competitiveness	Ground-mounted	France	2014	2015			
		Germany	2016	2018			
		Italy	2015	2016			
		Spain	2014	2015			
		United Kingdom	2019	2022			

source: EPIA, 2012

Table 14 - Impact of DSM measures on competitiveness

Competitiveness type	Market segment	Country	• Low prices • Low WACC • Average irradiation	• Impact of DSM increasing to 70% (residential segment) or 100% self-consumption (commercial/industrial segments)
Dynamic grid parity	Residential	France	2014	2012
		Germany	2014	2012
		Italy	2012	2012
		Spain	2015	2012
		United Kingdom	2017	2015
	Commercial	France	2015	2014
		Germany	2013	2012
		Italy	2012	2012
		Spain	2012	2012
		United Kingdom	2015	2014
	Industrial	France	2018	2018
		Germany	2015	2014
		Italy	2012	2012
		Spain	2018	2016
		United Kingdom	2019	2018

source: EPIA, 2012

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