Design and impact of
a harmonised policy for
renewable electricity in Europe

WP5 Summary Report

Derivation of prerequisites and trade-offs between electricity markets and RES policy framework

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The beyond*2020* project *at a glance*

With Directive 2009/28/EC the European Parliament and Council have laid the grounds for the policy framework for renewable energies until 2020. **Aim of this project** is to **look more closely *beyond 2020*** by designing and evaluating feasible pathways of a harmonised European policy framework for supporting an enhanced exploitation of renewable electricity in particular, and RES in general. Strategic objectives are to contribute to the forming of a European vision of a joint future RES policy framework in the mid- to long-term and to provide guidance on improving policy design.

The work will comprise a detailed elaboration of feasible policy approaches for a harmonisation of RES support in Europe, involving five different policy paths - i.e. uniform quota, quota with technology banding, fixed feed-in tariff, feed-in premium, no further dedicated RES support besides the ETS. A thorough impact assessment will be undertaken to assess and contrast different instruments as well as corresponding design elements. This involves a quantitative model-based analysis of future RES deployment and corresponding cost and expenditures based on the Green-X model and a detailed qualitative analysis, focussing on strategic impacts as well as political practicability and guidelines for juridical implementation. Aspects of policy design will be assessed in a broader context by deriving prerequisites for and trade-offs with the future European electricity market. The overall assessment will focus on the period beyond 2020, however also a closer look on the transition phase before 2020 will be taken.

The final outcome will be a fine-tailored policy package, offering a concise representation of key outcomes, a detailed comparison of pros and cons of each policy pathway and roadmaps for practical implementation. The project will be embedded in an intense and interactive dissemination framework consisting of regional and topical workshops, stakeholder consultation and a final conference.

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This report

identifies key design elements for electricity markets and grid regulation that, on the one hand, minimize non-desired impacts of RES policies on electricity markets and grids; and on the other hand, remove barriers for the integration of large RES-E shares

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1 Introduction

Previous reports within the Beyond2020 project have already emphasized the need to analyse carefully the interactions between RES-E support instruments and electricity markets, grid policies and regulatory designs. As stated in these reports, the growing penetration of RES-E into European power systems makes the saliency of these interactions larger, and the need to address them more pressing.

Deliverable 5.1 of this project reviewed these interactions between RES-E support instruments and electricity markets, networks and regulatory designs, based on the existing literature on the topic. In fact, given the scarcity of previous studies, particularly on how regulatory design of RES-E and wholesale markets and grid regulation affects both the RES-E deployment and the overall power systems efficiency, the report even tried to advance the discussion about these issues, although from a mostly qualitative approach.

The first contribution of the report was to propose a methodology that, instead of taking the different RES-E support instruments as such, decomposed them into design elements, which are the ones that actually determine outcomes and interactions. Table 1 shows how the policy pathways considered in the project can be decomposed into design elements.

Table 1 List of policy design elements influencing markets and grids

Common design elements					
Techologies eligible for support (all vs. only new plants)					
Flow of support (constant or decreasing)					
Duration of support					
Cost burden (taxpayers, consumers)					
	Concerned pathways				
Instrument specific design elements	FIT	FIP	QUO	QUO(b)	TEN
Demand orientation	x				
Technology specific support	x	x		x	x
Size-specific support	x	x		x	x
Location-specific support	x	x		x	x
Minimum/maximum support prices (cap/floor/penalty)		x	x	x	
Cost-containment mechanisms	x	x			
Purchase obligation	x				x*
Forecast obligation	x				x*
Support adjustments	x	x	x	x	
Distribution of proceeds from penalties/deposit			x	x	x*
Regulatory / support framework					
Cooperation with third countries					
Eligibility of plants in other countries					
Distribution of grid connection costs					
Degree of harmonisation					
General support characteristics					
Exposure to market risk (support tied to hourly market prices)					
Support based only on ETS					

* Depends on the actual organisation of the tender

The report then showed the multiple interactions that appear between these design elements and electricity markets and networks, and identified the more relevant ones. These are: the merit-order effect (including the assessment of how RES-E may influence the probability of negative prices); price volatility; system adequacy; balancing costs and needs; and grid investment and operation effects.

- Merit order effect: the introduction of RES generally depresses wholesale market prices, although this depends on the system configuration: In some cases, average prices might remain stable (if the marginal technology remained the same), or might even increase (if the marginal technology is the same and fuel costs, CO2-costs or cycling costs increase). When prices do go down, the signal for new investment that the market sends is reduced, and income for existing producers also decreases. This might be corrected with other instruments.
- Price volatility: the intermittency of RES will increase the volatility of wholesale market prices.
- Negative prices: when RES are subsidized, negative prices may increase their frequency (negative prices are not only caused by RES promotion), since RES will be interested in being dispatched at negative prices in order to keep receiving the subsidy, if the subsidy is linked to generation (the limit for the negative price is the amount of the subsidy). This effect is reinforced when there is priority of dispatch for RES.
- Market power may also be affected depending on the policy instrument chosen. When RES power plants bid into the wholesale market and their income depends, even partly, on wholesale prices, the amount of inframarginal energy increases and hence the incentive for agents to exert their market power if any.
- Generation adequacy: a large introduction of RES may affect the adequacy of the generation system, that is, its ability to supply demand at all times. Current systems may not be flexible enough to respond to intermittent RES. This is compounded with the price depression effect, which reduces the signal for new investment and therefore limits the possibility of adjusting the system with more flexible capacity (demand side management, storage and conventional power plants).
- Network effects: Depending on how it is done, introducing more RES into the power system will require the expansion of the power grid. Using them efficiently (and also building additional capacity) may also require designing the right rules for cross-border trade and cost recovery.

Then, deliverable 5.2 assessed quantitatively those interactions, or at least those for which it was possible to do so, and also, given its relevance for the assessment of some of the effects, estimated the impact of the different policy pathways proposed on the market value of RES-E.

In this internal report we summarize the findings of both deliverables, and make recommendations about the elements of design of electricity markets and grids that may allow a large penetration of RES-E

Section 2 reviews the major interactions between RES policy frameworks and electricity markets, and Section 3 estimates the magnitude of these interactions, based on the quantitative assessment performed in task 5.2. Based on these outcomes, Section 4 identifies the key design elements for electricity markets, and Section 5 does so for grid regulation. Finally, Section 6 formulates some recommendations for key elements in the design of electricity markets and grid regulation that might allow for a larger penetration of RES-E.

2 Major interactions between RES policy frameworks and electricity markets

This chapter introduces in a first step effects of VER on grids and markets that have already been identified in the literature. These issues have been examined from different perspectives and there is rapidly growing amount of literature on this topic. The objective of this section is to present the major open issues that have been identified along with the major electricity generation system functions, and to classify them in a logical fashion to facilitate an orderly discussion. However, some preliminary new ideas (or at least some new perspectives on well-known topics) will be introduced.

Due to the fact that not all renewable technologies contribute to these effects in the same way, Deliverable 5.1 analyses the characteristics of the most important renewable technologies and shows their respective contribution to each effect.

2.1 General discussion of influences

The effects of the penetration of renewable generation will affect market decisions made at all timescales and across geographic regions, since a variable and only partly predictable source of power generation, with zero variable costs, will be brought about to a power system that has to balance generation and varying demand at all times. At high levels of penetration, the characteristics of the bulk power system can be significantly altered. These changes need to be considered and accommodated into the current planning and operation processes, which were not designed to incorporate large volumes of VER generation. Multiple new issues must be addressed, ranging from increasing power system flexibility by a better utilization of transmission capacity with neighbouring areas, to demand side management and optimal use of storage (e.g. pumping hydro or thermal), changes in market rules to schedule the plants closer to real time or many other aspects related to the generation unit commitment. For instance, the future mix of generation technologies will have to accommodate the strong presence of intermittent generation and be able to cope with more cycling, fewer hours of operation and different patterns of electricity prices[1]. This and many other key factors are largely discussed later in this report.

In general, several effects of an increasing renewable penetration on markets and grids have already been identified. Roughly speaking, the policy and regulatory intervention to favour the deployment of RES-E has a number of expected effects in the functioning of wholesale electricity markets:

- From the very long to long term, the expected outcome is a maximization of the energy systems sustainability, and thus, a minimization of the energy supply costs in the future. The implementation of RES-E support mechanisms is already leading and expected to lead to a significant increase on the learning curve of a number of RES-E technologies[2]. As stated, from the electricity supply costs perspective, in the very long term, RES-E are expected to turn into a huge improvement of efficiency.

[1] Storage, at scale, represents the most straightforward way to deal with these issues. However, storage at the low cost and large scale needed will take some time. In the interim, if a large deployment of VER happen to take place –which will likely be at the decadal scale– other sources of flexibility will be needed.

[2] Indeed this has been for instance the case of wind generation, whose costs have been reduced dramatically in the last two decades, to such extent that currently they are close to turn wind production into a technology which does not need any support to enter into power system. See for instance the auction prices that resulted from the auctions held in Brazil (Batlle & Barroso, 2011).

- From the long to the medium term, the strong presence of VER will imply a re-adaptation of the generation technology mix. In the medium term, the load factors of the currently installed conventional generating units will decrease and in the long term, in principle, if regulatory incentives are properly designed, a higher proportion of less capital-intensive alternatives (generating units and demand response solutions) is expected to be installed. Due to the wide variability of RES-E, in most of the electric power systems[3], the need for the so-called back-up capacity will be larger than the one related to other sources. From the total cost of energy supply side, RES-E imply a lower reduction of capacity needs than other generation alternatives, but at the same time, in principle this capacity will have lower investment costs.

- From the medium to short term, on the one hand, VER entail a zero- or low-cost energy contribution. On the other hand, particularly in mainly thermal systems, due to the fact that the VER production is less correlated with the demand needs, VER imply a very significant change in the scheduling regime of the rest of the generating facilities in the system. This issue will have a key impact not only in the short-term operation of electricity systems, complicating significantly the unit commitment problem, for thermal plants will have to cycle intensively; it will also condition significantly capacity expansion, since not only low capital investment units will be needed, but also flexible ones, characterized by less relevant operation constraints, minimizing the cost of cycled scheduling. Again, from the operation cost perspective, in these shorter terms (e.g. from one week to one day ahead real time), the impact of VER is bidirectional, meaning a price decrease due to a reduction of variable operation costs (i.e. fuel costs) and a price increase due to thermal units constraints, since the related costs will have to be internalized in shorter time periods, and thus their weight in the cost per MWh produced can be significantly larger.

- From the short to the very short term, the unpredictability of VER generation in the short term leads to a larger need of provision of reserves. Although there has been a positive evolution in the forecast error in the last years, -e.g. in the Spanish system, beyond five hours ahead, this error is still around 15% (Imaz, 2011)-, the larger the amount of VER installed in the system, the larger the costs related to reserves contracting.

In the sections that follow this general introduction on the influences of RES-E on electric power markets, the discussion is particularized on the so-called VER. Next, just to support this general approach that opens this section, we first very briefly introduce the main technical characteristics of the two main VER, wind and solar PV, the ones expected to be deployed in a larger extent in the near future. More details about these technologies, and also about hydro and biomass, can be found in Deliverable 5.1. Then, as an introduction to the detailed discussion on a technology basis, we will divide this first general review according to the different time spans previously outlined, starting from the short term (ancillary services needs), discussing then the impact on unit commitment costs and spot market prices and closing with the expected influence on generation investment and thus on system adequacy.

2.2 Variability characteristics of wind and solar generation

Wind and solar generation are both intermittent. Intermittency comprises two separate elements: non-controllable variability[4] and partial unpredictability. Non-controllable variability implies a likelihood that an individual plant could be unavailable when needed that is significantly higher than in conventional plants. Note that the output of a plant could conceptually exhibit much variability, while being 100% predictable. Although the output of any actual power plant is variable and unpre-

[3] This is not for instance the case in those systems in which storage capacity is abundant, as it is the case of the mostly hydro-based ones, e.g. the Brazilian power system.

[4] Although in the vast majority of cases it is still not taking place, VER curtailment, negative balancing and ramp rates control is technically possible. In any case these actions are just unidirectional, as VER output can only be reduced.

dictable to a certain point, wind and solar generation have these characteristics in a degree that justifies the qualification of “intermittent”.

Wind generation is variable over time, due to the fluctuations of wind speed[5]. Although figures are very much system-dependent, some illustrative statistics can be found in EURELECTRIC (2010): for instance, on average, only 4% (2.5% in Spain, 5.5% in Germany) of the total wind installed capacity has a probability of 95% of being present at all times, which is a similar level of availability expected in conventional power plants.

Especially the deviation of actual wind generation from day-ahead forecasts becomes increasingly important at higher penetration rates (Weber, 2010; Obersteiner & von Bremen, 2009). The variability of wind generation also decreases with spatial aggregation. Wind energy output over larger geographic areas has less variability than the output of a single wind power plant.

Although forecast techniques are significantly improving over the years, predicting wind’s output is much more difficult than predicting the output of conventional generators or load. Generally, only very near-term wind predictions are highly accurate (Xie et al., 2011). In particular, the error for 1- to 2-hour ahead single plant forecasts can be about 5-7%; for day-ahead forecasts, the error increases up to 20% (Milligan et al., 2009).

Solar power is characterized by a diurnal and seasonal pattern, where peak output usually occurs in the middle of the day and in the summer, so it is quite well correlated with the hours of high demand of many electric power systems. On the other hand, due to the lack of thermal or mechanical inertia in PV systems, and the impact of clouds, rapid changes have been observed in the output of PV plants[6]. Spatial diversity, as with wind, can mitigate some of this variability by significantly reducing the magnitude of extreme changes in aggregated PV output.

Compared to wind energy, PV solar output is generally more predictable due to low forecast errors on clear days, and the ability to use satellite data to monitor the direction and speed of approaching clouds.

2.3 Requirements for operating reserves and other ancillary services

2.3.1 Increased need and costs for balancing or intraday adjustments

Following Milligan et al. (2010), operating reserves are defined as the real power capability that can be given or taken in the operating timeframe to assist in generation and load balance, and frequency control. There is also need for reactive power reserve, but it will not be discussed here. The types of operating reserves can be differentiated by: a) the type of event they respond to, such as contingencies, like the sudden loss of a generator or a line, or longer timescale events such as net load ramps and forecast errors that develop over a longer time span; b) the timescale of the response; c) the type of required response, such as readiness to start quickly a plant or fast response to instantaneous frequency deviations; d) the direction (upward or downward) of the response. See also Milligan et al. (2010) for a thorough international review of definition and use of reserves.

A critical issue in power system operation with a large volume of intermittent production is the amount of operating reserves that will be needed to keep the power system functioning securely and efficiently. The practical implications are: a) more expensive operation, as a number of plants

[5] For example, at the end of 2010 the installed capacity of wind in the Spanish system amounted to 20 GW, with a wind production record of 14962 MW on November 9th, 14:46, meaning at that time 54.2% of total production. Conversely, an annual minimum of 250 MW was recorded just three months before, on August 17th, 7:11.

[6] Although the ramping characteristics are fast for PV plants, the time it takes for a passing cloud to shade an entire PV system depends on factors such as the PV system size, cloud speed, and cloud height, among others. Therefore, for large PV systems with a rated capacity of 100 MW, the time it takes to shade the entire system will be on the order of minutes, not seconds (Mills et al., 2009).

have to be maintained in a state of readiness and kept from being used normally to generate electricity, regardless of the regulatory framework; b) a long-term impact on the generation mix, as appropriate investments have to be done to have these plants installed and ready when the level of penetration of intermittent generation makes these quick response plants necessary. A comprehensive review of the new requirements that intermittent generation may impose on power systems can be found in Holttinen et al. (2011).

While for lower shares of wind energy, balancing required for demand deviations is still the decisive factor, Consentec (2008a) find that extended balancing becomes necessary if the share of variable renewables exceeds 30% of electricity production (Milborrow, 2011; Weber, 2010). Another problem for balancing VER is that fewer power plants are available to provide the full spectrum of current balancing services. The reduced number of possible participants in the market especially for positive balancing services can reduce liquidity and increase prices in these markets. Thus, additional balancing services may be associated with significant costs (Erdmann, 2008; von Roon, 2011b).In Germany, liquidity in the intraday market has already improved but is not yet sufficient for the integration of large amounts of wind energy (Borggrefe & Neuhoff, 2011; Weber, 2010). In Spain, the need for balancing services remained constant despite a high penetration of wind in an isolated system due to the liquidity of the intra-day markets. Liquidity is reached there by the operation of six centralized intraday auctions (Borggrefe & Neuhoff, 2011).

A review of the numerous studies that have been made on the subject of the impact of intermittent generation on the need for additional reserves appears to lead to the following findings, which have to be adapted to the diverse characteristics of each individual power system:

- The observations and analysis of actual wind plant operating data have shown that, unless in those few cases in which extreme weather conditions arrive, wind does not change its output fast enough to be considered as a contingency event. Therefore the largest contingency to be considered in the determination of reserves is not affected by wind penetration. Also, both the uncertainty and the variability of wind generation may affect the required amount of regulating (secondary) reserves, but not significantly in most cases. Fast response reserves–frequency response and regulating reserves–should be ready to respond to quick fluctuations in solar or wind production. Since power systems already need these kinds of reserves to cope with load fluctuations and unexpected emergencies, the practical relevance on production levels or costs of the presence of VER on the demand for these reserves is not deemed to be of much relevance.

More important is the impact of errors in the prediction of the output of wind and solar on the day-ahead schedule of plants, since this requires having ready a significant capacity of flexible generating plants with relatively short start-up times and/or fast ramping capabilities, such as OCGT and CCGTs plants, to provide load following and supplemental (tertiary) reserves. Therefore, improvements in wind plant output forecasting offer a significant opportunity to reduce the cost and risk associated with this uncertainty (Lew et al., 2011), minimizing the need for more balancing and intra-day trading (Weber, 2010; Nievel, 2011). However, most authors do not consider higher quality wind forecasts as sufficient to solve the problem (Weber, 2010; Borggrefe & Neuhoff, 2011). Improvements in prediction require better models and more observational data. The benefits of wind output aggregation at power system control level and the need for large investments in observational networks favour centralization of the wind forecasting activities. The involvement of demand response can potentially reduce costs.

These additional requirements imply an increasing amount of mandatory dispatching of thermal units. It reduces the capability of generators to manage their portfolio (trading with these units is limited), and consequently reduces the offers on the commodity market and may increase market prices.

As pointed out in Holttinen H. et al. (2011), an ‘increase in reserve requirements’ does not necessarily mean a need for new investments, as countries already with much wind power have learned from experience. Note that most wind-caused reserves are needed when wind output is highest and, therefore, the conventional power plants must have more spare capacity to provide reserves. Critical issues appear to be the capability to follow steep long ramps if the wind forecast errors are large enough that the slow units cannot follow, although this matter could be mitigated by regulating wind plants (the so-called pitching).

2.3.2 Availability of other ancillary services

Power systems must be able to maintain their integrity while responding to different kinds of contingencies that take place in very short time scales: short circuits in lines, sudden loss of load or generation, or special system conditions that gradually become unstable. Power system stability is the ability of an electric power system, for a given initial operating condition, to regain a state of operating equilibrium after being subjected to a physical disturbance, with most system variables bounded so that practically the entire system remains intact (Kundur et al., 2004).

There are several forms of instability that a power system may undergo. Transient stability refers to the capacity of the generators to maintain the synchronism in the presence of transmission line faults. Spontaneous low frequency oscillations must be damped quickly. Frequency excursions due to abrupt imbalances between generation and demand should be contained and the frequency brought swiftly to its nominal value. Voltages have to be maintained within safe boundaries at all times. The allowed response time to these contingencies typically ranges from some milliseconds to a few seconds or even minutes, therefore with some overlap with the activity of fast operation reserves. The most crucial factors for the stability of a power system are its mechanical inertia (provided by the rotating masses of all the turbines and the electricity generators) and its capability to damp any perturbation (Rouco et al., 2008).

The physical characteristics of wind and solar PV plants are substantially different from those of thermal plants–including concentrated solar power units–which consist of a boiler producing high-pressure steam that drives a turbine rotating in the same shaft with a synchronous generator. The ability to regulate frequency and arrest any sudden rise and decline of system frequency is primarily provided through the speed droop governors in conventional generators.

In principle, the inertial response of wind turbines and solar PV plants to the overall power system is almost negligible. Therefore, in systems with a high penetration ratio of wind farms, the effective inertia of the system may be reduced and the system response to large disturbances could be significantly affected. This situation is more likely to happen for system conditions with a strong wind output and light demand. In particular, small standalone or weakly interconnected systems, as for example the Irish or the Hawaiian power systems, are more vulnerable to contingencies like the sudden loss of generation (Xie et al., 2011).

An additional consideration is that long transmission lines are required by power plants that are located far from the main load centers–typically hydro, nuclear and, more recently, large wind or solar plants. The synchronizing power capability of these lines is significantly reduced when they are heavily loaded (Gautam et al., 2009).

2.3.2.1.1 Power management and frequency control

Many modern wind turbines are capable of pitch control, which allows their output to be modified in real-time by adjusting the pitch of the turbine blades. This capability can be used to limit ramp rates and/or power output of a wind generator and it can also contribute to power system frequency control. A similar effect can be realized by shutting down some of the turbines in a wind farm. Unlike a typical thermal power plant whose output ramps downward rather slowly, wind plants can react quickly to a dispatch instruction taking seconds, rather than minutes. Operators need to understand this characteristic when requesting reductions of output. Examples of implementation of these techniques to provide frequency control can be found in Martínez de Alegría et al. (2004) or Gautam et al. (2009).

Detailed simulations of a large penetration of wind generators equipped with doubly fed induction generators in the New York (assuming 10% wind) and WECC (assuming 20% wind) regions, have shown that wind plants can actually contribute to system stability by providing low voltage ride through capability and dynamic VAR support to reduce voltage excursions and dampen swings (GE ENERGY, 2005). From the WECC system frequency response study, results have shown benefits provided by special wind plant controls specifically contributing to system frequency performance during the first 10 seconds of a grid event by providing some form of inertia. These cases show that wind generation does not necessarily result in degraded frequency performance (Miller et al., 2010).

Large PV solar plants can potentially change output by +/- 70% in a time frame of two to ten minutes, many times per day. Therefore, these plants should consider incorporating the ability to manage ramp rates and/or curtail power output. The use of inverters in solar PV plants makes them able to provide real-time control of voltage, supporting both real and reactive power output. Due to their energy storage capability, the electrical output ramps of a solar thermal plant can be less severe and more predictable than solar PV and wind power plants.

Concentrating solar thermal plants that use steam turbines typically make use of a “working fluid” such as water or oil; molten salt may be used for energy storage. The mass of working fluid in concentrating solar thermal plants results in these types of plants having stored energy and thermal inertia. Due to their energy storage capability, the electrical output ramps of a solar thermal plant can be less severe and more predictable than solar PV and wind power plants.

2.3.2.1.2 Voltage control

Most wind generators that were deployed more than a few years ago were equipped with minimum voltage protections that can trip the unit, with the purpose of protecting both the machine and the power system. As noted by Rouco et al. (2006), a large amount of wind power generation can be tripped if the voltage dip affects a large fraction of the power system with much installed wind capacity, leading to a potential system collapse. Depending on the technology being used, the dynamic response of wind power generators to voltage dips may be different. A sudden significant loss of wind production may also occur when wind velocity in a region happens to exceed the safety specifications of the plants, which then have to shut down immediately.

Voltage control can also be implemented in wind power plants, which, as well as PV plants, can control reactive power. As variable resources, such as wind power facilities, constitute a larger proportion of the total generation on a system, these resources may provide voltage regulation and reactive power control capabilities comparable to that of conventional generation. Further, wind plants may provide dynamic and static reactive power support, as well as voltage control in order to contribute to power system reliability. The most demanding requisite for wind farms, especially those equipped with doubly fed induction generators (DFIG) is the fault ride through capability. The effect of such a voltage dip in the wind turbine is different for different wind turbine system technologies. Voltage ride-through can be achieved with all modern wind turbine generators, mainly through modifications of the turbine generator controls. Older types of wind turbine-generators at weak short-circuit nodes in the transmission system must be disconnected from the grid unless additional protection systems are provided, or there may be a need for additional transmission equipment.

2.3.2.1.3 Grid codes and VER as ancillary services providers

All these factors, plus the knowledge that large levels of penetration of wind and also solar PV are anticipated to take place in many countries, lead to two major conclusions. First, the operation of power systems with a strong presence of VER has to be profoundly reconsidered and grid codes have to be adapted to this new situation (Tsili et al., 2008). Second, wind and solar PV plants can no longer be regarded as passive units, shutting down when system faults occur and with local control of regulation. In this new context, they must behave as much as possible as ordinary power plants, which are able to provide reactive power, remain connected during system faults and increase the amount of control effort required to stabilize system frequency (Xie, et al., 2011). These features are considered essential for the future integration of high wind penetration in electric power systems.

The good news is that wind generation is technically able to actively participate in maintaining system reliability along with conventional generation. It is now possible to design wind generators with a full range of performance capability that is comparable, and in some cases superior, to that in conventional synchronous generators. This includes voltage and VAR control and regulation, voltage ride-through, power curtailment and ramping, primary frequency regulation and inertial response.

2.4 Changes in electricity wholesale prices

Experience and modelling show that increasing shares of renewable electricity lead to changes in the level and volatility of energy wholesale prices.

2.4.1 Merit Order Effect

First of all, electricity wholesale market prices at times of high renewable generation and thus average electricity wholesale prices are reduced due to the Merit Order Effect (Bode & Groscurth, 2006; Morthorst and Awerbuch 2009; Haas, 2011; Traber et al, 2011; Sensfuss et al, 2007): wind and solar generation directly reduce the wholesale market price, since a zero variable cost energy contribution replaces expensive fossil-fuel electricity production. However, it should be reminded that this effect is not necessarily a social benefit, but just a transfer between producers, since costs decrease at the expense of incumbents (which cannot now recoup their investment costs).

Figure 1 shows a stylized merit order curve (the example is taken from the German market). The right curve includes more must-run renewables plants. The resulting new price is lower than the original price as plants with higher marginal costs (in this case gas-fired plants) are driven out of the market.

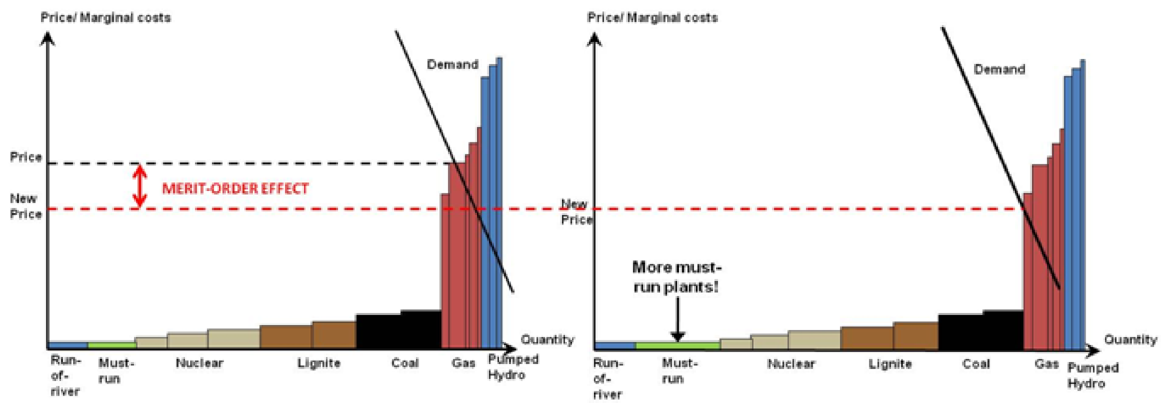

Figure 1. Merit order effect

It has been traditionally argued that especially high wind and solar generation reduce the electricity price in the wholesale market at least in the short term (Felder, 2011; Wissen & Nicolosi, 2007; 2008; Nielsen et al, 2011). The merit order effect has been quantified by several authors (Pöyry & EWEA, 2010; Green, 2010; Labandeira et al, 2009). Sensfuss et al (2007), as an example, estimate that renewables have reduced the electricity price by 7.83 Euro/MWh in 2006. Schüppel et al (2011) find that price effects are bigger in times of high demand as the merit order curve is steeper at the margin.

However, the calculation and quantities are debated. Pérez-Arriaga & Batlle (2012) note that while this effect is undoubtedly significant from a cost perspective, in a wholesale generation market the price reduction may be less important. This happens when the addition of wind does not change the technology that sets the marginal price in most of the hours of the year. This is often the case in Europe with systems with a large component of combined cycle gas turbines (CCGT). To date, the newly installed CCGT plants worldwide are quite standard, with similar heat rates and also fuel costs within each power system. Most of the drop in electricity prices that has been observed in some of these electricity markets, as in Spain, might be better explained due to the reduction of the CCGT load factors, and the activation of the inflexible take-or-pay clauses included in the natural gas supply contracts[7].

In the longer term, as argued in the next section, new investments have to be considered – if less base load plants and mid merit plants are part of the electricity mix, peaking plants with higher marginal costs are used more frequently. According to some authors this might lead to an increase of the average wholesale price (Erdmann, 2008; Wissen & Nicolosi 2007; 2008; Green, 2011).

2.4.2 Increasing cycling and price peakiness

The second impact is due to the lack of correlation of wind production with demand. Wind output alters the shape of the net load to be satisfied with conventional thermal generation, therefore changing the traditional way to schedule the thermal portfolio. Peaks of thermal production no longer occur when demand is highest. In addition, VER production may result in such a low value of net demand (mostly at night in the case of wind, and during the day in the case of solar PV) that will force a large number of thermal units to shut down only to have to start up a few hours later.

The term “cycling” refers to the changing operating modes of thermal plants that occur in response to varying dispatch requirements: on/off operation, low-load cycling operations and load following. Lefton et al. (1996) put forward a good qualitative summary of the impacts of fossil power plant cycling operation: significant increase in equivalent forced outage rate (EFOR), additional capital and maintenance expenditures and increase fatigue-related and creep-related wear and tear. These translates into a significant cost increase caused by operation, maintenance, and capital spending, replacement energy and capacity cost due to changed EFOR, cost of heat rate change due to low load and variable load operation, cost of start-up auxiliary power, fuel, and chemicals, cost of unit life shortening and general engineering and management cost (including planning and dispatch).

Since the increasing penetration of wind and solar is unavoidably going to lead to a significant increase of these cycling-related costs, any sound economic analysis needs to properly take these expenses into consideration, particularly due to the fact that the actual and expected costs of cycling fossil units that were originally designed for base-load operation is greater than most utilities had estimated.

The extent to which the combination of a large penetration of VER, the resulting increased cycling needs and the impact of technical operation constraints of conventional generating units may affect the economic dispatch of the power system and the electricity market outcomes in the future is an active research topic at the present moment. There is a growing number of modeling analyses that deal with the impact this new scheduling regime will have in the short to medium term, as for example Denny (2007), Delarue et al. (2007), Goransson and Johnsson (2009) and Troy et al. (2010).

Batlle et al. (2012) review the sources of costs that are expected to suffer changes as the penetration of VER (and thus thermal cycling operation) grows. Significant costs are incurred when shutting down and starting up a thermal generation plant. A considerable amount of fuel is needed to raise the boiler to its minimum operating temperature prior to producing electricity. Moreover, the heat-

[7] For example, if a CCGT unit expected to produce 6000 hours per year and signed a contract with a pay penalty of 25% of the price for the first 5000 hours, but it happens later to expect an actual production of only 3000 hours per year (due to the large penetration of wind, or demand reduction because of the economic crisis or simply flawed investment planning) its opportunity cost (i.e. its rational bid in the market) is reduced by 25%.

ing and cooling processes intensify the wear of plant equipment that shortens the maintenance cycles. Cycling, and starting-up in particular, accelerates component failure, resulting in an increase in failure rates, longer maintenance and inspection periods and higher consumption of spares and replacement components. The results are higher operating and maintenance costs and lower plant availability.

These costs can be conceptually framed within three main factors, namely:

- Fuel start-up costs (fuel needed to heat the boiler);
- Energy production costs as a function of the incremental heat rate curve (that is, a curve taking into account the efficiency-loss costs due to suboptimal operation regime[8]);
- O&M costs (reflected in a Long-Term Service Agreement), which strongly depend on the operating regime.

As thoroughly analyzed by Batlle et al. (2012), the impact of the increase in the number of starts on the maintenance of the generating units turns to be a crucial factor in the power system operation when a significant amount of renewable generation is installed. As a summary, the previous components of the total cost are expected to change when a large amount of wind and particularly solar enters in the system. The fuel start-up cost can increase or decrease due to the fact that the number of starts will increase at the same time that the cost of each start will decrease. As mentioned, this is because the number of hours between two consecutive starts is lower in the presence of wind and/or solar. The energy production cost is expected to rise as a result of the increase in the number of hours producing below the maximum output. In most cases (as a result of the abovementioned effects), the larger the number of starts, the larger the additional operation and maintenance cost each start causes. Starts are responsible for shortening the maintenance period and therefore the annualized value of the maintenance costs. Therefore, the O&M cost increases in the presence of wind and/or solar due to the reduction of the time between two consecutive maintenances caused by the higher number of starts. The cost increment due to this last effect can be two or three times larger than the fuel start-up cost, which has traditionally been the only start-related cost one that had any impact on the operation costs of conventional thermal plants.

The impact of these effects on price is to steepen peaks. In off-peak periods, when expensive minimum load thermal operation that would not normally be dispatched comes into play by lowering prices below production costs, it takes the place of less expensive generation, prompting a re-arrangement of the merit order. The ultimate result is that the marginal price is set by units with lower generating costs. Prices tend to decline. During peaks these units need to recover their start-up, shutdown and minimum load costs, raising the price of power.

Pöyry (2009) and Green (2011) show using a modelling approach for the UK, that price volatility in the short term increases substantially with higher shares of variable generation. Both negative prices and high scarcity prices occurred frequently in their simulation. Studies for the German market also predict more volatile and less predictable prices for the EPEX day-ahead market (Nicolosi & Fürsch, 2009). However, for 2010 and 2011, peak prices have almost disappeared from the German spot market and price volatility was reduced as the market has become more competitive but also that the increased share of solar power is pushing down prices at peak times (LBD, 2011).

2.4.3 Negative or zero electricity wholesale prices

Electricity generation from VER is less flexible in following electricity demand. This is especially true for variable and weather-dependent renewables such as wind, solar PV, river hydro and to a

[8] Given the cost involved in stopping and re-starting plants, one alternative is to keep them running at the minimum possible output. Production costs (fuel consumption) are higher (per unit generated) at minimum load operation than at full capacity. Plant efficiency is lower, further increasing the extra production costs attributable to this factor.

lesser extent concentrated solar power. Depending on the chosen support policy, also dispatchable technologies such as biomass, biogas and reservoir hydro are incentivised to generate without considering price and demand developments. As a consequence, at times of low demand, oversupply of electricity can lead to very low or even negative electricity wholesale prices.

The variability of a high share of generation in a completely renewable system leads to changed load profiles for non-variable plants (Pöyry, 2011; Nicolosi, 2010; Obersteiner & von Bremen, 2009; MacCormack et al, 2010). Currently, this can be observed in the phenomenon of negative or zero prices already occurred in those PX in which the VER presence is more significant (see Figure below).

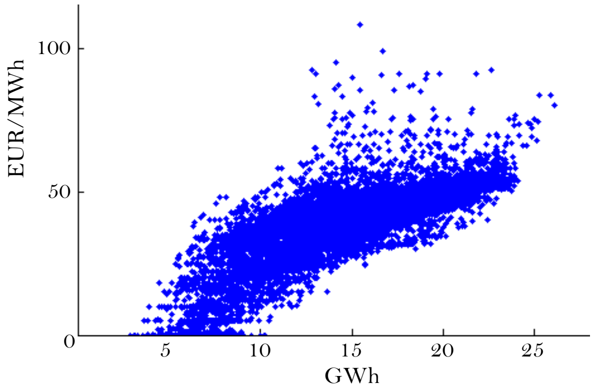

Figure 2. Prices in the Spanish market in 2010

As described by Pérez-Arriaga & Batlle (2012), the presence of VER in power systems has frequently motivated the creation of ad hoc market rules to deal with the new patterns of behaviour that have been encountered. A prominent case is the so-called "priority of dispatch" rule included in the EU legislation –the Renewables Directive 2001/776– to promote the development of renewables. This requires that "Member States shall ensure that when dispatching electricity generating installations, system operators shall give priority to generating installations using renewable energy sources in so far as the secure operation of the national electricity system permits and based on transparent and non-discriminatory criteria". The practical effect of this rule is that production with renewables can only be limited because of security reasons. Therefore, whenever the market price equals zero or a negative value, even if the optimal solution of the unit commitment algorithm indicates that the most economic option is to curtail wind rather than to stop some conventional thermal plant for a short period of time, renewable production will be scheduled and receive the feed-in tariff or premium, if this is the case.

Several reasons have been given to support this drastic rule. In the first place, the rule helps meet the committed renewable production targets, as well as any carbon reduction targets, by minimizing curtailments of renewable production. The rule may also incentivize a more flexible operation – to avoid being driven out of the market– of conventional plants that, otherwise, might not try to make an effort to accommodate increasing volumes of intermittent generation. In addition, it also helps to reduce financial risks for investors and therefore may reduce support costs.

The down side of this rule is that it may be the cause of inefficient dispatches of generation, as it may constrain what otherwise would be the optimal unit commitment, whether based on generators operating costs or bids. Note that conventional generators may be willing to bid negative prices to avoid being shut down. This is normal rational economic behaviour of the agents in a competitive market and should not be interfered with. Wind or solar generation would be also willing to bid a negative price to retain the income from any financial support scheme that is linked to production, although this might not be considered acceptable.

As an example, negative bids are allowed in the German electricity wholesale markets since 2008 and negative prices have already been observed. These price developments are sometimes seen as useful for the market as a signal to restructure the generation fleet but they increase costs for renewables support (Nicolosi, 2010). While negative prices are mostly associated with an oversupply of wind energy, there are several additional structural reasons. First, in the German system grid operators sell all renewable electricity in the electricity wholesale market regardless of the price. Second, many plants on the system are not very flexible. Thus, they only stop generation as a reaction to negative prices if these are expected for a longer period as otherwise costs for ramping the plant up and down as well as the opportunity costs of minimum standstill times are more expensive than a short period of negative prices. The last issue is that plants have to produce at a certain level to be technically able to offer balancing services when called upon (Andor et al, 2010; Brandstätt et al, 2011).

2.4.4 Market power

Market power is one of the most important challenges in the present electricity system in many European countries. It can incur high costs for society as market prices are artificially increased. Due to the special characteristics of electricity, the power sector is particularly prone to market power (de Hauteclocque & Perez, 2011). In addition, price volatility in a system with high shares of renewable generation is accentuated with a high degree of market concentration (Green, 2010). Apart from wholesale market prices, market power can also increase costs for re-dispatch and balancing (Neuhoff, 2011).

The value of renewable electricity in the wholesale market is lower than that for electricity generated from other sources (Bushnell, 2010). According to Twomey & Neuhoff (2010) this is the case especially for wind which already contributes considerably to overall electricity production and is not correlated with the demand profile. These authors state that in a system with market power, average prices for wind can be even lower (Twomey & Neuhoff, 2010). Green (2011) however states that in the UK market wind generators that have a high output in winter get almost the same average prices as conventional generators.

Batlle et al. (2011) discuss that when remuneration of RES-E installations is tied to short-term energy market prices, as it is the case in the feed-in premiums regime, RES-E receive market signals that may lead to more efficient operations, but, conversely, this approach also creates incentives for incumbent generators to increase their market power by assembling a generation portfolio that includes both RES-E infra-marginal capacity and conventional units.

2.5 Generation adequacy: Changes in the future mix

A number of noteworthy papers have discussed how RES-E can change the optimal capacity mix in the long term. For example, Lamont (2008) and Nicolosi and Fürsch (2009) include the consideration of RES-E in the standard screening curves approach to illustrate how increasing VER leads in the long-run to a lower share of base-load technologies and a lower average utilization of the generating capacities. Bushnell (2010) and Green & Vasilakos (2011) assess the long-term impact of the introduction of large amounts of wind on electricity prices and capacity expansion (in the US and Great Britain respectively), extracting similar conclusions on the basis of stylized equilibrium models.

However, there is still a significant lack of tools and literature dealing with the implications of detailed short-term operation costs on the long-term capacity expansion problem, which may no longer be negligible when the amount of VER becomes significant. One attempt in this respect is the one developed in Traber and Kemfert (2011), where a simplified representation of start-up costs is included in a long-term analysis focused on evaluating the need for regulatory technology-oriented incentives.

2.5.1 Flexibility

In this new context, a key factor that minimizes the cost increase of the economic dispatch is the flexibility capability of the thermal plants. The cost impact of a large introduction of VER will therefore be inversely proportional to the amount of existing flexible generation: the larger the inflexible capacity (older coal units and nuclear, typically), the larger the operation costs; and the larger the flexible capability (including storage facilities and demand response services) the lower these costs.

The role of those technologies that until now have been considered inflexible (older coal and nuclear, typically) will have to diminish radically. In the future they will probably exhibit more flexibility if the incentives exist to make proper investments in refurbishing the plants and changing the maintenance contracts.

A power system can respond with flexibility to the variability and uncertainty of VER with more resources than new investments in flexible power plants. To start with, as indicated in the previous section, a very important source of flexibility is the spare capacity of already existing flexible power plants. For instance, the New England Wind Integration Study (NEWIS) has revealed that the ISO-NE system presently has adequate resources to accommodate up to 24% of annual energy penetration of wind generation by 2020, see GE Energy et al. (2010).

Demand response holds a huge potential that still has to be demonstrated; see FERC (2011). This includes applications that have been used for a long time, such as interruptibility contracts with large industrial consumers, as well as others that still are in its infancy, like tapping the response of smart domestic appliances or of large aggregates of medium size consumers, as the company ENERNOC has already achieved.

Capacity credits

While there is agreement regarding the fact of the lower availability of weather-dependent renewables, there is a heavy discussion regarding the capacity credit of these technologies. The capacity credit is the percentage at which capacity of a power plant can be taken for granted and thus can be used to calculate system adequacy and operational margins. The exact value of assumed capacity credits therefore determines the need for storage or back-up plants for VER.

From a reliability perspective, according to NERC (2009), the system planner has to maintain some percentage reserve margin of capacity above its demand requirements to maintain reliability following unexpected system conditions. Reserve margins are determined by calculating the firm capacity of supply resources; this requires that some fraction of the rated capacity be discounted to reflect the potential unavailability of the resource at times when the system is in high-risk of not being able to meet all the demand.

If a large portion of the total supply resource portfolio is comprised of VER, the reliability evaluation becomes more complex. However, this does not fundamentally change existing resource adequacy planning processes in that the process must still be driven by a reliability-based set of metrics. The analytical processes used by resource planners range from relatively simple calculations of planning reserve margins to rigorous reliability simulations that calculate probabilistic measures of loss of some demand.

The capacity contribution of conventional generating units to reserve margins is mostly based on the unit performance rating, forced outage rate, fuel availability and maintenance schedules. However, the capacity contribution of VER is not straightforward, as it will depend on their variability and uncertainty, as well as on the correlation of their output with electricity demand. It has been noted in NERC (2009) that current approaches based on the “Effective Load Carrying Capability (ELCC)” or “Capacity Factor” (CF) may need to adapt to properly include VER, see also IEA (2011). Thus, for ELCC, the weather-driven correlation between VER and demand is critical, where a large amount of time-synchronized hourly RES-E generation and demand data is required in order to estimate its capacity contribution. For CF calculations, the definition of high-risk reliability periods has been identified as key for calculating the capacity value of wind. Approximations should be avoided and more detailed approaches, such as ELCC with abundant historical data should be employed.

For a conventional, dispatchable plant, capacity credits of 95% are typically assumed. For VER, capacity credits are undoubtedly lower although the importance of this factor is very dependent on specific system characteristics, such as interconnection or hydro storage capacity. Exact estimations vary however widely, especially in the case of wind energy and will therefore be further discussed in the following sections.

Capacity credits of some renewable technologies namely solar PV and wind are relatively low. Thus more installed capacity or other measures such as increased storage or demand side management are necessary to keep the same level of security of supply (Gross et al., 2006). The need for additional capacities can be at least partially mitigated by an increase in demand side management and the introduction of smart grid technologies (Wilson, 2010).

In several studies it has been noted that the capacity value of wind decreases as the penetration of wind increases, indicating that its incremental contribution to reliability decreases (NERC, 2009) (ESB National Grid, 2004). The contribution can be up to 40% of installed wind power capacity in situations with low penetration and high capacity factor at peak load times, and down to 5% under higher penetration, or if regional wind power output profiles correlate negatively with the system load profile. The smoothing effect due to geographical distribution of wind power has a positive impact on the wind capacity value at high penetration, subject to having enough capacity in the grid (Parsons & Ela, 2008). It remains to be well understood the logic behind this result, which is probably the effect of a “common cause of failure”: a quasi-simultaneous absence of the wind resource throughout the entire system. The larger the presence of wind in a system, the stronger this negative impact is on the system reliability performance.

Note also that a sudden loss of all RES-E power on a system simultaneously, e.g. due to a loss of wind is not a credible event. It might happen because of automatic disconnection in case of excessive wind velocity, but this can be mitigated by adequate control measures. A sudden loss of large amounts of wind power, due to voltage dips in the grid, can also be prevented by requiring fault-ride-through from the turbines.

The worst credible scenario for VER under a reliability viewpoint consists of an extended period of time –maybe as long as a few days– with very low output, during a high demand season. It is very important to characterize the probability of occurrence and the depth and duration of these events, since the power system has to be ready to cope with them.

The lower predictability of renewable generation when compared to conventional power plants can also reduce system reliability. As explained above, the need for balancing and intraday adjustments as well as the need for ancillary services might increase.

2.5.2 Cost recovery and investment incentives for non-variable plants

In power systems under competitive market conditions generation capacity expansion is left to the decentralized decisions of private investors, who will evaluate the convenience of building plants in a particular power system depending on the expected price levels and operating conditions during the lifetime of the potential facility, among other considerations. There is an ongoing discussion whether energy-only markets are suited to allow for high enough scarcity prices in periods of low excess capacity to provide sufficient investment incentives even in a conventional system (Joskow, 2006; Batlle & Rodilla, 2010). Furthermore, so far no nuclear or renewables plants have been built relying on the market alone. For example in the UK; most investment after privatisation went into combined cycle gas turbines (CCGT) with comparatively low capital and high operational costs and the operator of nuclear plants went bankrupt in a market with a low share of renewables due to low gas prices (Clough et al, 2011). The changes in the electricity wholesale market described above (lower average and more volatile prices as well as changing load profiles) lead to even harder conditions for cost recovery and investment incentives. The uncertainty regarding the adequate technology mix, the penetration of renewables, and the economics of such a mix under the anticipated future prices and operating conditions raise concerns about attracting sufficient investment in these flexible plants under a competitive market regime.

Several studies for a diversity of power systems –see for instance MIT (2010), DOE EERE (2008), GE Energy (2010), Charles River Associates (2010), Poyry Energy (2009)– have analyzed, in detail, plausible future scenarios with a large presence of wind and solar generation, and shown that, if the market mechanisms would properly work, this also should lead to an increased presence of flexible mid-range generation capacity with high cycling capability and low capital cost. The function of some of these plants –typically open cycle gas turbines, OCGT– is almost exclusively to provide reserve capacity margins. Other plants are subject to heavy cycling regimes with relatively low capacity factors (e.g., 2000 to 3000 hours per year), typically combined cycle gas turbines, CCGT. These results are obtained under the assumption of centralized planning. Ideally the same mix should also be the outcome of a competitive electricity market.

However, a number of recent studies conclude that capacity mechanisms are necessary to provide sufficient investment incentives (WWF, 2012; EWI, 2012; RAP, 2012).

2.5.3 Grid infrastructure, market and re-dispatch

Often, the best renewable energy potentials are not located near centres of electricity demand. In Germany for example, wind parks are so far mostly built in Northern Germany while the highest demand for electricity occurs in the South of the country (Moser, 2009; DENA, 2010). Wind potentials in the UK are best in Scotland and other Northern areas as well. On a European scale, solar potentials are best in Southern countries while wind potentials are highest in the North.

Therefore, depending on the technology mix and geographical distribution of renewables resulting from the selected policy path, current existing infrastructure might become insufficient for providing secure electricity supply.

This is the case both within but also between Member States. In Germany, regular grid congestion along the North-South corridors can already be observed and is expected to further increase (Neuhoff, 2011; E.ON, 2011b; Moser, 2009; Wawer, 2007b; Inderst & Wambach, 2007). The same is true for other European countries.

Grid congestion also leads to a higher need for re-dispatch. For example the German electricity market treats the national grid infrastructure like a copper plate i.e. plants are dispatched regardless of their location respective to demand without considering the possibility of grid congestion. So far, this is no problem as the grid is designed to incorporate maximum power flows from plants. Grid congestion does not occur frequently and re-dispatch costs are therefore still low (Schmitz & Weber, 2011; Boot & van Bree, 2010). The necessity for re-dispatch and thus the costs for integrating renewable electricity are however rising.

2.5.4 Ownership structure and market power

Power plants based on renewable energy have a more diverse ownership structure including farmers, communities and households. This is probably even true if current efforts of incumbents to invest in big renewable generation units are taken into account. The new actors can possibly reduce market concentration and thus possibilities for exerting market power (Ackermann, 2007).

2.6 Grid regulation

There are two significant lines of interaction between RES-E and grids. In one direction, the deployment of RES-E has an important influence on the way the grid is to be built and regulated. On the other hand, grid regulations (particularly regarding cost allocation rules) have a large influence on RES-E deployment. Since, at least concerning the first aspect, there are significant overlaps with the design of the electricity market, we will address this topic in more detail in section 4.

2.6.1 Challenges of RES-E for grid infrastructure

Often, the best renewable energy potentials are not located near centres of electricity demand. In Germany for example, wind parks are so far mostly built in Northern Germany while the highest demand for electricity occurs in the South of the country (Moser, 2009; DENA, 2010). Wind potentials in the UK are best in Scotland and other Northern areas as well. On a European scale, solar potentials are best in Southern countries while wind potentials are highest in the North.

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As previously introduced, the fact that often the best renewable energy potentials are not located near centres of electricity demand implies that RES-E may increase the need for new interconnectors, both at the national and European level. There is however not much literature on how to allocate the costs of these interconnections, although some recommendations on how to address the issue at the EU level for the connection of offshore wind farms have already been put forward by Meeus et al (2012), in which three guiding principles are proposed to minimize the total investment cost of transmission and generation: the planning principle, the competition principle, and the beneficiaries pay principle. The authors also argue for the benefits of combined solutions (mixed farm to shore and shore to shore investments).

Another challenge arises due to the increasing congestion of the grids (in turn due mostly to the difficulty of building new lines). In this context, variable energy sources can add complexity to the operation of the grid, and modify the context in which decisions are made over nodal or zonal prices. As mentioned before, this is discussed in more detail in section 4. Let us summarize this by saying that nodal prices would improve significantly the operation of the grid, and would also make fuller use of the existing network in Europe, as shown by Neuhoff et al (2011).

3 Estimation of the different interactions assessed

In this section we give a quick overview of the results produced within Task 5.2 and already presented in Deliverable 5.2.

The data regarding installed capacities of renewables in different European countries for modelling the effects of increasing shares of renewables on electricity markets was taken from the output of the Green-X model (used mainly in Workpackage 4 of the project). For the market modelling, four policy scenarios were selected out of the list of possible policy pathways (as developed by the project) and analyzed in order to represent a wide variety of outcomes. For the analysis of price and grid effects, data for all European countries was used (although with a limited level of detail in the case of the grid effects outside Southwestern Europe), effects on reserve markets were modelled with data for Spain. As mentioned earlier, the effects on system adequacy were only modelled for one high-RES scenario.

The first of these scenarios **"NOPOL"** serves as a baseline under which renewables are only supported by an ETS system after 2020. This policy pathway results in a lower overall share of renewables compared to the other pathways. Electricity market prices are relevant for investment decisions and thus technology choice and locations of renewable plants in this scenario.

In the other scenarios, an equal share of renewables is reached (at the European level, not at the regional level) and support levels are set in order to enable cost recovery for renewable plants. Under policies where price risks are taken by investors in renewable plants (i.e. quota systems and feed-in premiums), risk premiums are included in the calculation of necessary support levels, through the WACC.

The scenarios considered are:

- A harmonized quota system (**"HARMQUO"**):
  In this scenario, the support given is technology neutral and does not differ between locations. Market price signals (represented by expected average market revenues per technology) are taken into account by investors in RES plants.
- A harmonized feed-in tariff (**"HARMFIT"**):
  Under this policy, the support to renewables is given as a harmonized fixed feed-in tariff. However, tariffs are not equal across Europe but differ between geographic locations based on resource quality. Differences in electricity market prices have no influence on location or technology mix as the income for renewables is independent of electricity market prices.
- A national feed-in premium (**"NATFIP"**):
  Under this policy, all member states use the same support instrument, a fixed feed-in premium. Support levels thus differ between member states and market price levels influence investment decisions.

Unfortunately, the task was not able to provide a joint, consistent assessment of all interactions. This would have required the combination of many assessment methodologies into a single instrument, which would then be applied to the entire European region. Because of the serious limitations in the availability of both data and modelling tools, we resorted instead to using different tools, applied to different regions in Europe. However, and in order to be able to compare to some extent our results, we used (except for the assessment of system adequacy) the same scenarios for RES-E deployment. These scenarios were generated in WP4 with the Green-X model. Also, the same set of prices for fuels, carbon allowances, etc., were used, in this case taken from PRIMES high-res scenario.

Although the lack of an integrated tool prevents us from providing consistent, global estimates of the total impact of RES-E support on electricity markets and grids, it does allow for understanding the magnitude of these impacts and how they depend on the support instrument chosen or other factors, so that they can be taken into account when designing support instruments, electricity market rules, or grid regulation.

3.1 Price effects

The analysis of the price effects had the following results:

- A number of factors influence the general price level in electricity markets: These include the CO_2 and fuel prices, the capacity level compared to overall demand, the degree of interconnection and market coupling, the share of renewables in the system and system flexibility.
- Therefore, rising renewable shares do not necessarily lead to lower average electricity prices. Prices will however decrease, if capacities are too high in general or if the electricity mix and flexibility of the system do not correspond to the needs of the rising renewable shares.
- The analysis confirms that rising renewable shares increase price volatility in the electricity spot market. Negative prices (or very low prices if negative prices are excluded by regulation) occur more often in a system with higher shares of renewables.
- Both effects might increase risk premiums for investments in both, renewables and conventional power plants or other flexibility options. They can however be partially mitigates by using smoothing effects through more extensive interconnector capacities. The impact of increased interconnector capacities is most pronounces in scenarios with a harmonized support scheme.
- The market value factor of renewables decreases as expected with higher shares of the respective renewable technology. The effect can also be mitigated by further interconnection capacities.

In general, the analysis confirms that rising shares of renewables have an influence on electricity market prices. These effects can however be superseded by other factors such as fuel price developments etc. Nevertheless, investment conditions for conventional power plants and other flexibility options might become more risky and hence more expensive in a system with high renewable shares. All effects can however be partially mitigated by increasing grid capacities and system flexibility.

3.2 Balancing needs

As mentioned in section 2.2, the impact of different RES policy scenarios on balancing needs and costs in 2030 was assessed for the Spanish system so that indicative results could be obtained for the European power system. In this sense, the results presented in this section must be carefully analysed. First, the total RES generation share in Spain in 2030 (70% in HARMFIT, 66% in HARMQUO and NATFIP, and 43% in the NOPOL scenario) is higher than the RES share assumed to be achieved in Europe by 2030 (around 55% in HARMFIT, HARMQUO and NATFIP, and 35% in the NOPOL scenario. Furthermore, the particular characteristics of the Spanish power system (i.e. conventional generation and interconnection capacity) may also influence the resulting impact of RES generation on balancing needs and costs. Finally, the fact that conventional generation capacity is kept constant in all policy scenarios has important implications on the results of this analysis.

Despite this, some important conclusions can be extracted from the study performed in Section 4.3:

1) As a result of higher RES penetration levels in HARMFIT, HARMQUO and NATFIP scenarios, the number of operation hours of conventional generation technologies is significantly lower in comparison to the NOPOL scenario. Consequently, the system marginal cost is also re-

duced, which, together with fewer operation hours, decreases the incentives to invest in conventional generation technologies, which are the main providers of balancing resources.

2) At the same time it displaces conventional generators, RES production increases system balancing needs. As it was seen in section 4.3, upward reserve use increase in HARMFIT, HARMQUO and NATFIP scenarios in comparison with NOPOL mainly due to higher intermittent generation forecast errors. Nevertheless, downward regulation increase not only due to higher production forecast errors, but also due to more frequent situations of excess of generation in the system. It also observed that the full deployment of downward reserve required RES curtailment during several hours in the scenarios with high RES penetration. In this sense, if non-conventional RES generators are not allowed to provide reserves in systems with massive penetration of intermittent generation imposing higher reserve requirements will increase RES generation curtailment.
3) Regarding balancing costs, the model computes marginal reserve costs as the increment in system operation costs resulting from keeping thermal units operating above their minimum output operation point (for downward reserve provision) and below their maximum output operation point (for upward reserve provision). Due to use of more expensive generation units for reserve provision in the NOPOL scenario, helped by the availability of cheap regulating resources (hydro power plants and pumped hydro storage capacity) in the Spanish system, reserve costs decreased in the scenarios with high RES penetration in comparison to the NOPOL scenario. However, it is important to have in mind that the conventional generation mix can be significantly different in a system with relative low RES generation penetration from the one in a system high RES penetration. This could have important implications on reserve costs.

In the light of these results some recommendations can be drawn: first, the participation of non-conventional RES generators in ancillary services provision will be essential for the integration of massive RES generation. Other sources of flexibility should also be integrated in power systems, such as storage capacity, demand response and virtual power plants. Furthermore, interconnection capacity plays a major role in the integration of power systems and can contribute significantly for a higher RES integration. Finally, market rules must be adapted in order to facilitate a higher participation of RES generation in electricity markets.

3.3 Network effects

The results presented and analyzed in the previous sections indicate that the network investment costs for a system are very much related to the amount of new RES generation installed in the system and the location of this new RES generation. In general, network costs should be higher:

- The higher RES generation is;
- And the further RES generation is from load centres

RES generation tends to be located far from load and conventional generation. Thus, the greater the production with RES, the more different the power flows should be from traditional ones. Therefore, required reinforcements of existing transmission lines should be larger and possibly new transmission lines should also be built where RES generation is installed and no previous conventional generation was located.

The main conclusions for each of the considered RES policy scenarios follow:

- The HARMFIT scenario features the highest network development costs because its level of RES generation is high and the location of this generation is not guided by energy market prices. As a consequence, new RES generation in it is installed far from the load.
- Network investment costs in the NATFIP scenario are also high because new RES generation in this scenario, which is largest, has an incentive to be installed close to load centres with-

in each country but, not having a harmonized scheme of support payments at European level, the distribution of RES generation among countries and technologies may be far from being optimal.

- The HARMQUO scenario features the lowest network investment costs because it has less RES generation in the considered region (France, Spain and Portugal) than the other two "green" scenarios and this generation is installed where market revenues tend to be larger, i.e. it is installed closer to demand than in other scenarios.
- The NOPOL scenario features the lowest investment costs after the HARMQUO scenario. RES generation in the NOPOL scenario is less abundant than in the other three scenarios. Moreover, RES generation in the NOPOL scenario has a natural incentive to be placed close to demand, since its revenues are a function of market prices. These two factors should press network investment costs low. However, given that the market value of RES generation in this scenario is very high, developing the network to maximize the integration of available RES generation into the grid makes economic sense, while in other scenarios some RES energy spillages can be justified. Besides, some additional conventional generation needs to be connected to the grid in this scenario to serve the system peak load (the contribution of RES generation to serve peak load in this scenario is lower than that in other scenarios). All this taken together results in final network costs in NOPOL being low but, still, a bit higher than those in the HARMQUO scenario.

3.4 System adequacy

The analysis presented in section 4.4 allows the extraction of the following generic results:

- *Impact of RES deployment:* large-scale deployment of RES capacity acts as a disincentive to the deployment of conventional power plants, leading to insufficient capacity margins and endangers system adequacy. Assuming a stagnating conventional generation fleet, Germany, France and Belgium are countries in the CWE region that will need substantial backup capacity.
- *Role of market integration:* for integrated markets, the required amount of back-up capacity more than halves compared to the case of isolated countries. For specific countries, market integration is enough to ensure sufficient generation system adequacy, without the need of extra backup capacity (as in the case of Belgium).
- *Role of interconnection:* By increasing interconnection capacity in integrated markets, further gains in generation system adequacy are achieved, since further cross-border share of backup capacity is possible. For the CWE region, increasing the interconnection capacity by 20%, leads to a further decrease in needed backup capacity by 24%.
- *Centralised vs decentralised approach:* The system-wide LOLE is lower than the sum of the national LOLEs due to the fact that that a loss of load event in several countries at the same time is relatively unlikely. Adopting an integrated system approach for the assessment of the generation system adequacy in Europe would therefore be a more cost-optimal solution. For this, a transformation of the national reliability targets to European reliability targets should be required.
- *Capacity needed*: The results also indicate that only a limited amount of back-up capacities is required in order to maintain the generation adequacy in a European system with high shares of renewable power sources. However, for more detailed assessment of the impact of variable renewable infeeds, the analysis should be performed for a longer time period.
- *Capacity mechanisms:* For systems with low generation adequacy, securing some additional capacity, is shown to increase the system adequacy levels significantly, which reflects the significance of capacity mechanisms.

4 Key design elements for electricity markets

Wind and solar power have only recently reached significant levels of penetration in some countries, but they are expected to grow much during the next few decades, and contribute substantially to meeting future electricity demand.

As mentioned before, wind, photovoltaic (PV) solar, run-off-river hydro and concentrated solar power (CSP) with no storage (referred to as Variable Energy Resources, or simply VER) have non-controllable variability, partial unpredictability and locational dependency.

One of the major present concerns in this respect is how these VER may affect the efficiency and remuneration of the different market agents in short-term (day-ahead and adjustment) electricity markets. As has been already discussed from different perspectives, see for instance Baldick et al (2005) and Litvinov (2009), the particular characteristics of the short-term electricity auction design, which includes the auction objective, the bidding formats and the pricing rules, may affect in general market results.

In this section, we discuss how the efficiency and results in each of the different short-term market designs may be affected by a high penetration of VER. We argue that a strong presence of intermittent renewable generation may exacerbate the different impacts of the alternative design options.

4.1 Day-ahead market design for high shares of RES-E

Short-term operation in the vast majority of the market-oriented electric power systems is critically conditioned (in some cases fully determined) by the results of a centralized auction algorithm managed by either an Independent System Operator (the common approach in the US) or an organized spot market, i.e. a Power Exchange (the widespread solution implemented in the EU). These algorithms do not just determine the daily system unit commitment, but also settle the remuneration for the generating units scheduled. The fact is that market outcomes differ depending on the particular design characteristics of these algorithms.

It is still not far from being clear to what extent these market results can be affected, and which are the key factors that need to be taken into account to evaluate this impact in the different electric power systems. Next, we focus on assessing the performance of the different short-term auction and pricing designs when a large amount of VER enters the system, in an attempt to shed some light to the discussion on which short-term auctions and pricing designs might be optimal in this upcoming context.

First, on the basis of Rodilla et al. (2012), the main and most common designs implemented in practice in organized day-ahead markets (DAMs) worldwide are classified and reviewed. Three main design elements of these DAMs are highlighted. Then we argue how there are three design elements that largely condition the potential market results when significant amount of VER is in place.

4.1.1 Alternative design elements of day-ahead auctions

Electricity wholesale markets are composed of all the commercial transactions of buying and selling of energy and also other related to the supply of electricity (the so-called operating reserves), which are essential for this to occur in adequate conditions of security and quality. These transactions are organized around a sequence of successive markets where supply and demand trade the abovementioned products related to the supply of electricity in different periods.

Roughly speaking, in organized short-term electricity markets the day-ahead market (sometimes half hourly, some others even every five minutes) prices are, in principle, determined by matching generators offers and consumers bids. However, this can be achieved in a number of different ways.

Short-term electricity auctions can be classified around three major criteria:

- Whether they use complex bidding or simple bidding;
- Whether the pricing rule is discriminatory or non-discriminatory;
- Whether single, zonal or nodal prices are computed.

A number of other aspects could also be distinguished (Baíllo et al., 2006): the trading intervals used (hourly, half hourly or even every five minutes), if portfolio bidding is allowed or not (i.e. if no link is required between bids and units or on the contrary each bid must refer to a particular unit), if is there a limited number of bids for each portfolio or unit per time interval, if price caps are implemented, etc. However, next we will focus on discussing the three ones previously highlighted as most relevant plus one more, if negatives prices are allowed and to what extent[9].

4.1.1.1 Complex versus simple auction

Since electricity is a very complex commodity, and its production is subject both to inter-temporal constraints and to the existence of a number of non-convex costs, the format of the generators offers can range from the so-called simple one (a series of quantity-price pairs per time interval) to a grayscale of more complex alternatives, in which inter-temporal constraints and/or multidimensional cost structures can be declared. We build our brief review of the main alternatives around the two extremes (complex and simple auctions), and then we introduce the hybrid alternatives implemented to amend these latter simple designs.

Complex auctions

In a complex auction generation agents submit offers, representing the parameters and costs which define best their generating units' characteristics (fuel cost, start-up cost, ramp up limit, etc.). With all these data, the market operator clears the market using an optimization-based algorithm which maximizes the net social benefit. This optimization algorithm shares most of the characteristics of the traditional unit commitment, but with the only difference that the data considered are market agents bids instead of costs. Usually, market prices are obtained as a by-product of the complex optimization-based algorithm.

Simple auctions

The downside of the complex-auction approach is the associated complexity of market clearing process. This factor has been the key argument held by (mainly) generators to move towards a much simpler auction, where the efficiency of the economic dispatch that results from the market clearing is sacrificed in favor of the transparency of the price computation process.

In the so-called simple auction scheme, the format of the offers does not explicitly reflect the generation cost structure (e.g. an offer component for the start-up cost) or imply any inter-temporal constraint. Instead, market agents submit simple offers/bids, which exclusively consist of price-quantity pairs representing the willingness to sell/buy the underlying product (one MWh in a certain time period of the day, e.g. an hour). Matching the market and obtaining the volume of electricity that is traded in each time period of the day is straightforward when offers and bids are simple: generation's offers are sorted in order of increasing prices and the demand's bids are sorted in order of descending prices.

[9] The discussion that follows is based on Rodilla et al. (2012).

Fully simple offers/bids do not imply any inter-temporal constraint. This means that for instance the offers of one thermal generating unit in the day-ahead market could be accepted in the third, fifth and seventh periods, leading to a resulting unit schedule which could be highly uneconomical or simply infeasible from the technical perspective. As we later further discuss, the main drawback of this approach is that it entails that to some extent generators have to anticipate (based on conjectures) the dispatch so as they properly internalize all cost in the hourly price component.

Hybrid or semi-complex auctions

In principle, the previous inconvenience could be partially fixed either by means of subsequent secondary trading (in the so-called intraday markets, in the EU context, or in the real-time market, e.g. in the US, see below) or closer to real time later in the balancing mechanisms/markets managed in most cases by the System Operator. However, in an attempt to combine the advantages of the complex and the simple auction design, EU PXs have opted for implementing hybrid alternatives, allowing linking semi-complex conditions to their offers.

The common idea behind the design of these semi-complex designs is simply to introduce as few complex constraints as possible in the auction, so as to not to complicate the matching process in excess while at the same time removing the huge risk at which agents are exposed in the simple auction context. Obviously, there is a whole continuum, between the extreme of including all potential constraints and the extreme of including none of them. The larger the number of constraints allowed, the closer the offers can represent the cost functions of the generating units.

In practice, this trade-off has been achieved either by introducing some of the most relevant (most difficult to be internalized) constraints, as it is the case with the ramp-up constraint (used in the Iberian day-ahead market) or by allowing some heuristic-based inter-temporal constraints in the offers format, in most cases not necessarily representing actual constraints or cost components, but rather a mixed effect of many of them.

Some of the complex conditions and offers used in semi-complex auctions are for example user-defined block bids (implemented, among others in the Nordpool, EPEX Germany and EPEX France), meaning that a market agent can offer/bid a price/quantity pair for a set of consecutive hours (three as a minimum), flexible hourly bids (Nordpool & EPEX France), i.e. price/quantity pairs with no pre-defined hourly period assignment or the so-called minimum income condition implemented in OMIE, enabling a generating unit to include a minimum income condition expressed as a fix (expressed in euros) and variable term (in euros per MWh) associated to the whole set of hourly bids corresponding to one particular unit.

4.1.1.2 Pricing rules: discriminatory versus non-discriminatory payments

The computation of market prices as well as the related determination of the generating units' remuneration is a quite controversial and still open issue in the context of complex auctions. We can classify these approaches in two large groups:

- non-linear pricing rules (also known as discriminatory pricing schemes), according to which, on top of the hourly prices, some additional side-payments are provided on a differentiated per unit basis;
- linear (or non-discriminatory) pricing rules, according to which the same hourly price is used to remunerate all the hourly production and no side-payments exist.

As it can be straightforwardly observed, the key factor that differentiates these two rules is that they yield different payments for consumers and correspondingly different income for generating units.

Non-linear pricing

In the context of complex auctions, non-linear (or discriminatory) pricing is undoubtedly the most extended pricing rule (especially in the US markets). This mechanism translates into each generator having a remuneration consisting of:

- first, a set of (non-discriminatory) prices which serve to remunerate all production in each time period,
- and then, some additional discriminatory side-payments (in practice computed as a lump-sum daily payment) which are calculated on a per unit basis.

As a consequence of the method used to compute marginal prices, these prices do not include the effect of non-convex costs (as it is the case with start-up or no-load costs). This is the reason why additional payments are considered on a per unit basis so as to ensure (if necessary) that every unit fully recovers its operating costs.

Linear pricing

Although the non-linear pricing approach is the most extended alternative in the context of complex auctions, linear pricing is also a possibility. Linear pricing in this type of auctions entails computing non-discriminatory hourly prices in such a way that all generating units fully recover their operation costs (thus avoiding the need for discriminatory side-payments of any kind), so in each time period (e.g. hour) every MWh produced is remunerated with the same hourly price.

Finally it is important to remark that we have just focused on the complex auction context. The reason is that the linear versus the non-linear pricing discussion has been less relevant in the context of simple auction. This is mainly because the question on whether or not the single price should internalize the effect of non-convex costs (such as the start up cost or the no-load cost) makes no sense in the simple auction scheme. In the simple auction context generators have to internalize all types of costs in their price-quantity pairs offers. Once submitted, there is no way for the market operator to make distinction on which part of the price corresponds to convex and which part of the price corresponds to non-convex costs.

4.1.1.3 Prices and transmission constraints: nodal, zonal and single pricing

A number of regulatory options are open to deal with the allocation of limited transmission capacity for transactions among players under normal market conditions[10]. One way to differentiate the main categories of options is to gather them in two main groups: those pricing algorithms that involve a detailed representation of the transmission network, and those other which consider a simplified one.

Nodal pricing

Nodal pricing applies security constrained economic dispatch to derive a bus by bus Locational Marginal Prices (LMP), the prices paid for the energy consumed or generated at a given transmission node.

Combining the definitions of LMPs provided y PJM Interconnection and ISO-NE in their websites, we have that LMPs reflects the value of energy at a specific location at the time that it is delivered. If the lowest-priced electricity can reach all locations, prices are the same across the entire grid. When there is transmission congestion (heavy use of the transmission system in an area), energy cannot flow freely to certain locations. In that case, more expensive and advantageously located electricity is ordered to meet that demand. As a result, the LMP is higher in those locations.

[10] This initial description benefits from Rivier et al. (2012).

Nodal energy pricing provides an accurate description of the technical and economic effects of the grid on the cost of electricity. They implicitly include the effect of grid losses and transmission congestion, internalising both effects in a single value (monetary unit per kWh) that varies at each system node.

Zonal pricing

Zonal pricing consists of using a single market price except where significant grid constraints arise frequently between a limited number of sufficiently well-defined zones of the power system. Once the most frequent points of congestion are identified, the grid nodes affected by internodal congestion are grouped into areas or zones. As defined by Baldick et al. (2005), in this context "a zone is a set of nodes in geographical/electrical proximity whose prices are similar and are positively correlated over time. This pricing mechanism distinguishes energy prices by zone in lieu of by nodes, and the same price prevails at all nodes within a given zone.

A widespread alternative which can be considered as a particular case of zonal pricing is the so-called single pricing model, i.e. transmission congestion is fully ignored when the electricity market is cleared. This alternative is implemented in those markets where supposedly no systematic or structural congestion occur.

Thus, the market is first cleared in the day-ahead PX considering the simplified representation of the network (e.g. taking into consideration predefined theoretical interconnection capacities between the zones or directly ignoring transmission congestion in the case of single pricing).

In the (supposedly) few cases in which grid constraints are detected, the System Operator re-dispatches the system, determining which players must withdraw from the system and which are to be included. Energy removed to solve the network constraint may be paid at the respective agent's bid price (if a specific bid related to the constraint solving mechanism is in place), at the opportunity price (energy market price less the price of the agent's bid), or not at all. When additional energy is requested, it is normally paid at the respective agent's bid price.

4.1.1.4 Negative prices

As it is well-known, electricity market clearing may sometimes result in negative prices. When this is the case, generation pays demand (and/or pumping) to consume electricity. But, why would generation be willing to pay for producing? There are two main reasons for this to happen:

- For some of the generating technologies (mainly thermal, such as nuclear or coal), it is very costly or even technically impossible to reduce their output (or stop producing) for short periods of time in which the demand level is not sufficiently high so as to accommodate all the output associated to these units. When there is at least one unit facing this very costly dispatch, it makes economical sense that prices go down to negative values, as they are supposed to reflect the opportunity cost (what the energy is worth)[11].

[11] By the way of illustration, let us consider a CCGT unit being scheduled from 0 to 5 a.m. and then from 6 a.m. to 17 p.m. That is, the unit would start-up to produce for five hours, then it would shut down and be offline for one hour, and then would have to start-up again to produce for twelve hours. Since the start-up cost is higher than the cost of producing at the minimum load output during one hour, this same unit would reduce production costs if it would rather be kept online at this minimum load output during the interval that goes from 15 to 16 p.m. In this case, it is easy to derive that this CCGT would be willing to pay for producing during this hourly interval, but, how much? The answer is as much as the total costs it could save by producing in that hour. When a unit facing this situation is marginal in the hours she would be willing to pay for producing, the market price should ideally go to negative values.

From this point of view related to thermal operation, there is no discussion about the fact that negative prices are a reasonable and efficient expected market result (however, as we discuss a few lines below, pricing rules do not always allow this result to arise). Generally speaking, negative prices due to operation constraints are more likely to appear as a consequence of this costly or infeasible thermal operation regime, when the next characteristics meet in an electricity system:

- Thermal-dominated generation mix.
- System with large amounts of inflexible generation. This is for example the case when there is high nuclear penetration or when some type of generation enjoys priority or obligation of dispatch (this latter is the case with RES in most of the EU electricity systems, as later discussed).
- Low valley demand (minus inflexible generation) values when compared to peak and shoulder load (minus inflexible generation) values.
- Very low (or inexistent) demand elasticity and low pumping storage capability

But this is not the only driver behind negative prices. There is also another one (and possibly the main) driver which is close-related to some type of regulatory technology-oriented support mechanisms that we next describe.

- A number of subsidized technologies (mainly VER), are entitled to receive production tax credits, premiums, etc. on their electricity sold. This means that some generators are willing to sell their output for as low as the minus value of the incentive they receive to produce power. Wind generators are a clear example of this latter type of generator. If one of these subsidized generators happens to be marginal, prices will go to negative values.

Pricing rules may limit negative prices

It is noteworthy that some pricing rules do not allow whichever negative price to appear. This can be a direct consequence of explicit market intervention or rather a consequence of the details of the methodology used to compute prices. We next briefly describe these two different cases.

First, some systems have explicitly introduced a price floor that limits the potential negative value the price may reach. For instance, this price floor has been set to minus 100€/MWh in Ireland or to zero (thus, not allowing negative prices) in the MIBEL (Spain and Portugal) electricity market.

Second, a more subtle type of limitation can be implicitly embedded in the methodology used to compute prices. For instance, we have just seen how in some systems prices are computed as the dual variables (shadow prices) associated to the generation-demand balance constraint of the linear optimization problem that results when the commitment decisions have been fixed. But note that if the commitment decisions are fixed, the role start-ups costs may have in the actual value of the energy in one particular hour is lost. Thus, such methodology would never allow a price to reflect the opportunity cost of a unit that is being forced to shut down to then start up after for example just one hour. In other words, from the first of the two drivers highlighted above does not lead to negative prices in the non-linear (or discriminatory) scheme[12].

[12] In some complex auction designs agents are allowed to submit a negative value for their energy costs component ($/MWh). In some other markets, on top of the previous characteristic, it is also allowed the energy cost component to vary along the periods (hours) of the next day. In this latter case, it is somehow possible that some negative prices due to these thermal constraints would arise for generators are able to express the opportunity cost a start up may induce. However, note that this deviates from the previously mentioned objective of the complex bidding alternative, as a way to induce generators to declare the parameters actually defining their production cost structure.

4.1.2 Auction and pricing design for high shares of RES-E

Under normal circumstances, the particular design of the short-term market (format of the bids, market clearing algorithm and pricing and remuneration rule) conditions the market results. As discussed by Rodilla & Batlle (2012), a significant penetration of VER may exacerbate the outcomes of the different design elements just introduced. Next the arguments of these authors are developed.

4.1.2.1 Efficiency of the economic dispatch resulting from simple and complex auctions in the presence of VER

In the simple auction scheme, agents have to calculate the quantity-price pairs in such a way that all expected costs (including non-convex costs, such as the ones related to starts) are properly internalized. This way, for instance, a peaking unit expecting to have to start to produce electricity the next day in four hours (e.g. for the evening peak, from 6 p.m. to 10 p.m.) and then shut down, would have to impute all operation-related costs in those hours. Note that, since generators do not know in advance the resulting dispatch (e.g. the hours in which the unit will be finally committed), it is evident that this internalization is subject to risk (e.g. the market clearing results might imply that unit should be committed just two hours), and thus, may lead to inefficiencies in the resulting dispatch (the income in these two hours might not be enough for the unit to fully recover its operating costs).

On the contrary, complex auctions enable generators to better align their offers with their actual generating units' cost structure. This scheme allows agents to better express their willingness to buy and sell electricity, since it allows them to declare all parameters defining generation technical constraints (e.g. ramp-up and down limits, etc.) and generation costs (heat rate efficiency rate, hot start cost, cold start cost, wear-and-tear-derived costs, etc.). By providing all these detailed data, the generating unit is most likely scheduled in the most efficient way. In this context, the generator does not need to anticipate ex-ante which the resulting dispatch will be, since this intricate issue can be left in the hands of the optimization algorithm.

As previously stated, in the case of the day-ahead markets of EU Power Exchanges, in which simple bids were originally considered, this problem has been tackled in two sequential (ex-ante and ex-post) and complementary ways: semi-complex conditions aim at reducing the risk of market agents associated to the simple bid decision-making process, and secondary markets provide market agents with additional opportunities to reschedule their positions[13]. Thus, these two tools can be used to first avoid and then (if necessary) correct a non-profitable scheduling that has previously resulted in the day-ahead market.

Nevertheless, in practice these two alternatives are still far from solving the efficiency loss problem linked to simple bidding. First, secondary markets in theory would allow market agents to first solve the potential infeasibilities that might result from the day-ahead market clearing, and at the same time to gradually adjust their schedules to changing conditions. But on the one hand, transaction costs, although not significant, cannot be considered as negligible: being able to properly trade in these markets implies additional costs for market agents. And more importantly, due to the traditionally oligopolistic structure of a good number of electricity markets, these secondary markets have proven not to be always liquid enough, increasing the costs for particularly generators owning small generation portfolios, and thus affecting to their competitiveness[14].

[13] Intraday sessions as for instance the ones implemented in the Iberian or French cases or balancing markets as the ones also implemented in France or Elbas in Nordpool.

[14] See for instance Batlle et al. (2007). Although the situation apparently has improved after the implementation of intraday markets, observed balancing spreads have occasionally been rather significant.

Second, semi-complex conditions certainly are a valuable tool for market agents to mitigate their risk to face an uneconomical (or even technically infeasible) schedule resulting from the market clearing. But by no means they guarantee that efficiency of the schedule resulting from the market clearing is maximized. Most of the simple bids linked to semi-complex conditions explicitly or implicitly expose generators to the necessity of anticipating under uncertainty their expected dispatch. This is for instance evident in the case of block bidding, where generators have to decide the hourly interval in which they are willing to offer their energy (e.g. from 10 a.m. to 15 a.m.). Then, on the basis of this expected dispatch, it is possible to add a “kill-the-offer” condition if a minimum income is not perceived. In the example of the block bid, this is expressed usually through an average price.

Simple and semi-complex-conditioned offers allow for a significantly less flexibility than the complex bidding alternative. Note that the kill-the-offer condition allows avoiding the risk of losses for the generating agent, but does not avoid the risk of not being scheduled in the most efficient way from the standpoint of the overall system economic dispatch optimization[15]. For instance, an offer killed by the semi-complex condition may have been scheduled in some other intervals in such a way that both the system and the agent would have been better off.

VER and the efficiency of the auction design

A large penetration of VER directly increases the need for flexibility and thus for balancing resources. This has been the case in those markets in which the deployment of VER has been particularly significant, as for instance the German or Spanish cases, to name two particularly relevant examples. But, at least for the moment, since storage technologies and demand response tools are not yet sufficiently developed, this increasing need has not been accompanied by an equivalent addition of flexible technologies able to cope with it with the same level of efficiency. Thus liquidity is lower, and therefore the cost of adjusting the generation programs resulting for the market clearing are larger.

In the case of complex auctions, the presence of wind does not impact in a relevant way the generators strategies. Obviously, the associated uncertainty will introduce a risk component in the determination of the net social benefit, but this should not affect to generators’ offers, since again, the algorithm is the responsible of finding the optimal schedule.

In the case of simple auctions, ideally, under perfect information, the offers of all the market agents would also lead to the most efficient economic dispatch, the one corresponding to the equilibrium under perfect competition conditions. But in this case, a significant amount of wind in the system entails an additional source of uncertainty on the expected day-ahead market scenarios on which the bids building process of each market agent is based. The consequence is therefore that the disparity of these market agents’ estimations grows, and thus the errors are more likely and the market result further deviates from the optimum.

As argued by Vázquez et al. (2012), there is empirical evidence about the fact that VER significantly complicates the bidding task of market agents in simple and semi-complex day-ahead markets: bidders make an increasing use of semi-complex constraints as the amount of installed VER grows, as well as also these constraints activate the kill-the-offer condition accordingly. This kill-the-offer condition can allow some generators hedging from an incorrect assessment of the future market conditions when building the bids, but it will obviously will be too restrictive for some others whose production could probably have been scheduled in a different pattern than the one implicitly included in the semi-complex offer. When the amount of offers killed by the algorithm becomes large, the efficiency of the market results can be put into question.

[15] Ideally (in a competitive market) this solution is also supposed to represent the equilibrium, i.e. the desired schedule from the agent’s point of view in the absence of market power.

Take for instance the case of the Spanish system, where the deployment of wind and solar technologies has been more than remarkable[16]. Since the start of the market in Spain back in 1998, market agents operating in OMIE, the Iberian day-ahead market, can link their hourly quantity-price pairs to semi-complex constraints. The market clearing algorithm then searches for a solution that respects the constraints, so result is that a number of bids are killed. This is clearly illustrated in the figure below, in which for a particular hour back in 2010, the market matching, including the supply function before considering the quantity-price simple offers and the finally considered offer curve, resulting from the activation of the semi-complex conditions (in thick trace) are shown.

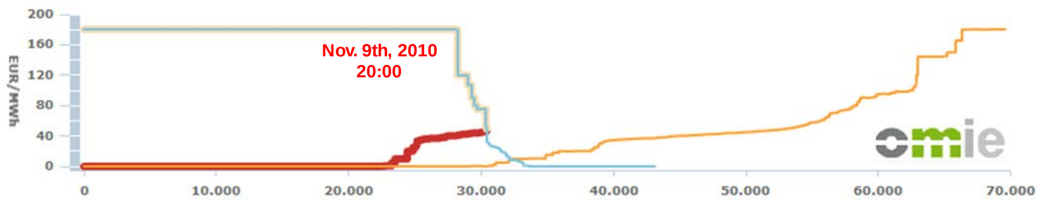

Figure 3 Renewable Market price settlement in OMIE

The effect that VER have had on the relevance of these semi-complex conditions is clearly illustrated in the figure below, taken from Vázquez et al. (2012). The withdrawn energy in the day-ahead market stemming from the activation of the minimum income condition in the peak hours is depicted along with the evolution of daily wind production from 2002 to 2010.

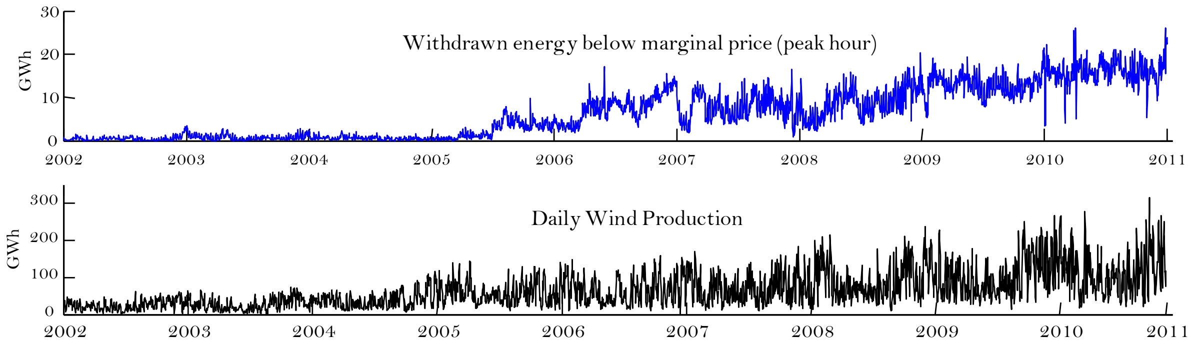

Figure 4 Energy withdrawn as a consequence of the activation of the complex conditions

As the installed capacity of VER (namely wind, but also a significant amount of solar PV, around 4 GW as for the end of 2010) has grown, the amount of energy discarded in the final market clearing due to the activation of semi-complex constraints has increased accordingly[17].

In the same line, Borggrefe & Neuhoff (2011) argue market design needs to allow generators to adjust their energy production and provision of balancing services in a joint bid, so that they can contribute to an efficient system operation.

4.1.2.2 Non-discriminatory versus discriminatory pricing in a context with high penetration of VER

Veiga et al. (2012) show how the pricing rules implemented (either uniform prices or the shadow prices resulting from the unit commitment plus additional side-payments) may amplify or reduce the resulting change on short term price dynamics due to the presence of VER. To do so, the authors

[16] As of the beginning of 2012, the installed capacity of wind was close to 21 GW, plus 4 GW of solar PV and 1.2 GW of solar thermal, while the recorded peak demand in 2011 was 44 GW.

[17] It is important to note that this increase cannot be attributed to a demand growth, since in the Spanish case electric power demand has experienced a very significant decrease from 2008 (281 TWh) to 2011 (261 TWh), a drop of around 7.5% in three years.

base their discussion on a simulation analysis using a detailed unit commitment model, able to capture the impact of cycling in the short-term price formation.

The two pricing contexts selected are respectively a simplified version of the pricing rules in force in the US ISOs short-term markets (as e.g. PJM or ISO-NE) and a simplified version of the pricing rules in force in the SEMO short-term market in Ireland. While in the first ones a uniform price not including non-convex cost is used in addition to some discriminatory side-payments to ensure operation cost recovery, in the latter just uniform prices including the effect of the non-convex costs serve to remunerate all generation.

The authors show how in the particular context of a system with large penetration of VER, non-convex costs are expected to increase and argue that, due to the increased impact of the non-convex costs of conventional thermal plants, the growing deployment of VER exacerbates these differences, which can have a relevant effect on the long-term capacity expansion of the system. It can be observed that the income in the linear pricing context increases when a significant amount of solar is added into the system due to the increase of the costs related to the larger need to start the plants and therefore to increase the O&M costs.

The authors illustrate how the income for a baseload plant is significantly different depending on the pricing rule implemented, what naturally would lead to a different generation mix in the future. The income in the discriminatory context is equal without and with a large penetration of VER as the calculated prices do not include the non-convex costs such as no-load or start-up costs of the marginal units and the marginal generator is a ccgt plant in both scenarios. Conversely, in the linear scheme, these start-up costs are perceived by all units.

One of the main conclusions extracted by Veiga et al. (2012) is thus that the role of short-term market prices as optimal long-term signals is to give incentives to bring in the most efficient investments (from the net social benefit standpoint). In order to give these optimal signals, prices need to reflect what the energy is worth, and this necessarily calls for internalizing all related-costs in the market price. Thus, in order to send proper sound long-term market signals, market prices should internalize the non-convex-cost-related component of the actual value of electricity.

4.1.2.3 Wind and efficiency of zonal pricing

Nodal prices implicitly include the effect of grid losses and transmission congestion, internalizing both effects in a single value (monetary unit per kWh) that varies at each system node. They are, therefore, perfectly efficient signals for economic decisions concerning the short-term operation of generation and demand, since they correctly convey the economic impact of losses and constraints at all producer and consumer locations. Gilbert et al. (2004) showed that implicit auctions maximise the use of transmission capacity.

In densely meshed transmission grids with no systematic or structural congestion, nodal pricing is often regarded to be an unnecessary sophistication and a limited number of zonal energy prices are preferred across the entire network. In these cases, under the assumption that grid costs have a relatively small impact on the market, grid effects are disregarded for reasons of transparency and simplicity. This approach is aimed at enhancing market standardization, increasing market liquidity.

But, as discussed for instance in Baldick et al. (2005), "when the transmission congestion within zones does not prove to be minimal, (...), then the allocation of zonal redispatch costs can quickly become large and inefficient". Next we briefly discuss how in most real cases, an increasing penetration of wind aggravates the inefficiency of zonal pricing.

Borggrefe & Neuhoff (2011) also argue that nodal pricing provides appropriate price signals for the economic design, encouraging the effective use of transmission capacity while improving interfaces between balancing and intraday markets.

When discussing the importance of implementing nodal pricing in the presence of large amounts of VER generation, two different cases can be tear apart:

- In some cases, particularly in the case of wind, the best sites to develop VER are concentrated in specific areas of the transmission system, sometimes far from demand[18]. As discussed for example in MIT (2011), the planning process in most restructured electric power systems is significantly more difficult than within vertically integrated utilities because decisions about the generation expansion are the result of market forces modified by the regulator's support for renewables and other policies, rather than centralized planning. When generator build times are shorter than those for transmission, planners are forced to either anticipate new generation and build potentially unnecessary infrastructure or wait for firm generation plans before starting the process and thereby potentially discourage new generation investment. The evidence is that, since transmission planning on the vast majority of cases takes much longer to plan, get approvals, and build a high-voltage transmission line than a wind farm or solar generating facility, currently transmission reinforcements are finally developed significantly later than what in principle it would be desirable.

  At least in the medium run, transmission will be increasingly constrained around these areas with good VER resources, so zonal pricing will lead to higher inefficiencies if the number of areas is not strongly increased to render zonal pricing closer to nodal pricing[19].

- In other cases, VER are irregularly dispersed in different areas of the system, often presenting different generation patterns. VER modify the patterns of power flows and prices so that the use of zonal pricing becomes increasingly inefficient.

4.1.2.4 Negative market prices in the presence of a large VER penetration level

We have seen that negative market prices may arise driven by two major factors: on the one hand, very costly thermal dispatches which could be avoided (lowered) in case demand consumption was higher in certain periods, and on the other hand, because of the existence of RES-E support mechanism that provides the installations with an out-of-the-market remuneration on a per MWh produced basis.

With these two major drivers in mind, we now qualitatively analyze the effect VER (mainly wind) may have on the appearance of negative market prices. But first, it is important to remark that this assessment cannot be performed without paying attention to the particular regulatory mechanisms supporting VER technologies. In this respect, two different factors of RES-E support schemes may affect to different extents the negative price dynamics:

- First, those mechanisms in which a "priority of dispatch" rule applies.
- Second, those in which they receive an out-of-the-market premium or production tax credit (PTC) based on their actual output.

[18] Just to mention three different examples of onshore wind, take for instance the case of Texas, where most of the wind farms are located in the West, Germany, in the North, and Rumania, in the southeastern region of the country, close to the Black sea. Obviously offshore wind aggravates this phenomenon.

[19] Although this is the most common situation, it has not been always the case. For instance, take the Spanish example: first, there are no significant differences among the wind mill load factors all around the country, and second, the FIT for wind resulted in more than 40,000 MW applications of interested capacity when the government target was only 2,000 MW per year installation (recently a renewable moratorium was announced). Instead of implementing auctions, which in principle it would have appeared as the best alternative, the System Operator, alleging transmission network stability and efficiency, allocated the permits in a disperse way all around the country, so no significant bottlenecks have yet appeared due to wind.

The first support scheme has a direct bearing on the potential appearance of very costly thermal dispatches. We saw that the larger the amount of inflexible generation, the more acute this issue may become. The so-called "priority of dispatch" rule included in the EU legislation –the Renewables Directive 2001/776– to promote the development of renewables establishes that "Member States shall ensure that when dispatching electricity generating installations, system operators shall give priority to generating installations using renewable energy sources in so far as the secure operation of the national electricity system permits and based on transparent and non-discriminatory criteria". The practical effect of this rule is that production with renewables can only be limited because of security reasons, so strictly speaking it would be fair to rename the rule as "obligation of dispatch", since for instance wind generators are not stopped even in those cases in which negative prices are well below the quantity of the feed-in tariff or the premium. In this context, these VER are nothing but an inflexible production which may push thermal units to more costly dispatches, that, as pointed out previously, may lead generators to be willing to pay for producing in certain periods (and this willingness may be quite large in some cases)[20].

The second factor is that a production-based incentive makes generators to be willing to sell their output for as low as the negative value of the incentive they receive to produce energy. This can also have a significant distortion effect that is larger the higher the incentive is. However, note that as long as VER production is committed in the market in this context, the price will necessarily be equal or above the offer VER submits to the market operator. Thus, unlike the previous case, when no obligation of dispatch applies, the distortion effect is limited, and prices cannot be below the negative price incentive as a direct consequence of VER production.

This latter argument leads us to an evident but also relevant conclusion. Negative prices are just a transitory consequence of the impact of the just discussed factors, but they will gradually disappear. PTCs apply to first 10 years of operation, and feed-in tariffs or feed-in premiums for as much as 20 years. Once this period is over, the VER installations will start to be fully exposed to market prices, and therefore they should be expected to produce only if it is economically efficient from the point of view of the whole system. Also, according to the observed learning curves of RES-E, specially wind but also solar PV, it should (hopefully) be expected that the time in which these technologies are fully competitive without needing any extra remuneration is close[21]. When any of these two or both situations occur, prices will then be naturally capped at a floor of zero (or close to zero). If a price ever falls below this value, it is either because there is no wind production at all (which is unlikely), or equivalently, because all wind energy production is being spilled for purely market-based economical reasons (probably as unlikely as the previous assumption).

4.2 RES and adjustment markets

4.2.1 The need for flexibility in system operation

As discussed previously, both the variability and uncertainty of VER ask for more flexibility of the generation portfolio and in the operation of the power system, including the design and utilization of transmission and distribution networks.

[20] Several reasons have been given to support this drastic rule. In the first place, the rule helps meet the committed renewable production targets, as well as any carbon reduction targets, by minimizing curtailments of renewable production. The rule may also incentivize a more flexible operation –to avoid being driven out of the market– of conventional plants that, otherwise, might not try to make an effort to accommodate increasing volumes of intermittent generation.

[21] In the Brazilian case, wind power has been winning generation auctions for ~110 BRL/MWh (~61 US$/MWh), full energy price.

System operators need to have generation, demand resources, or any other form of flexibility in the power system ready to respond whenever ramping and dispatchable capabilities are needed; for example, during morning demand pickup or evening demand drop-off time periods (NERC, 2009).

The power system needs more flexibility to handle the short-term effects of increasing levels of wind. The amount of flexibility will depend on how much wind power capacity is currently installed, and also on how much flexibility already exists in the considered bulk power system (Parsons & Ela, 2008). Even with perfect forecasting, wind generation will remain variable, for instance from one hour to the next, and for this reason additional flexibility is required.

There are several dimensions in achieving flexibility: a) better use of the flexibility that the existing system has or may have, for instance by changing market rules or by integrating current small balancing areas into larger ones; b) adding new flexible plants to the existing portfolio; c) utilizing flexibility contributions of the intermittent units.

There are different flexibility capabilities that are needed from all the power plants in a system with a strong presence of intermittent generation, corresponding to the different functions in power system operation, and ranging from fast response to frequency disturbances to the capability of shutting down and starting up again frequently. These capabilities include: a) ramping of the variable generation (modern wind plants can limit up- and down-ramps), 2) regulating and contingency reserves, 3) reactive power reserves, 4) quick start capability, 5) low minimum generating levels and 6) the ability to frequently cycle the resources' output. Additional sources of system flexibility include the operation of structured markets, shorter scheduling intervals, demand-side management, reservoir hydro systems, gas storage and energy storage. System planners and electricity market regulators must ensure that suitable system flexibility is included in future bulk power system designs, as this system flexibility is needed to deal with intermittency on all time scales. It therefore can be said that, as penetration of intermittent resources increase, system planners need to ensure that the added capacity has adequate flexibility to meet the total new flexibility requirements of the system. This is a new design requirement for future systems, and it can be met with local generation, interconnections with other systems or demand resources.

The contribution of most power plants to the flexibility of the operation of a power system is–up to a certain point–a function of the existing economic incentives. Technical minima, ramping capabilities, start-up times and hydro reservoir management can be modified given the adequate economic conditions. It is a regulatory challenge to define these conditions and a technical challenge to respond to them. See, for instance, the debate on the regulating capabilities of nuclear generation units in Pouret et al. (2009).

Demand response is another potential source of flexibility; see NERC (2009). Demand responsiveness by means of time-variant retail electricity rates, such as real-time pricing (RTP) or interruptible load agreements, could potentially reduce wind integration and forecast error costs. Through a price signal in the form of RTP, consumer demand could be made to follow the supply of wind generation, where if wind generation is high, for example, electricity demand will increase as a result of low electricity prices. Conversely, if wind generation is low, electricity demand will decrease as a result of high electricity prices (Sioshansi, 2010). Actual deployment of demand response schemes and an evaluation of its potential in the US can be found in FERC (2011).

4.2.2 Additional requirements of operating reserves

This issue has already been addressed in section 2.5.1 so we will not elaborate it further. It seems that careful attention must be given to the relationship between flexibility and reserves. It has to be realized that the need for flexibility is not the same as the need for reserves, which is smaller since a part of the variation of the net load–i.e. the original load minus intermittent generation output–can be forecasted. As it has been shown before, reserves mainly depend on forecast errors and the overall flexibility in scheduling deals also with the changes in output level for several hours and a day ahead; see Holttinen et al. (2011). These points out the open question of how to precisely define the flexibility requirements of a power system and how to incentivize the investment in the right kind of power plants and the provision of flexibility services.

4.2.3 Coordination of balancing areas

Large volumes of intermittent generation would be integrated much more easily in existing power systems if some institutional and organization problems could be properly addressed. One of them is the integration and coordination of balancing areas: the extension of the areas that are responsible for offsetting the variability and uncertainty of wind and solar production will smooth out the impacts and pool existing resources more efficiently and reliably.

As described in NERC (2009), ancillary services are a vital part of balancing supply and demand and maintaining bulk power system reliability. Since each balancing area must compensate for the variability of its own demand and generation, larger balancing areas with sufficient transmission proportionally require relatively less system balancing through operation reserves than smaller balancing areas[22]; see, for instance, Parsons et al. (2008).

With sufficient bulk power transmission, larger balancing areas or wide-area arrangements can offer reliability and economic benefits when integrating large amounts of variable generation. In addition, they can lead to increased diversity of variable generation resources and provide greater access to other generation resources, increasing the power systems ability to accommodate larger amounts of intermittent generation without the addition of new sources of system flexibility, and benefitting competition, removing entry barriers for new and small generation and retailing companies. In this line, Borggrefe & Neuhoff (2011) argue that coupling national balancing markets will then again increase market efficiency and reduce potentials to exercise market power.

4.2.4 Reduced scheduling intervals

Arrangements for the provision of the different kinds of ancillary services (and in particular operating reserves) widely depend on the individual power systems. In some cases the commitments for energy and some operating reserves are made at the day-ahead time range (e.g. the US power markets), while in others balancing energy transactions are scheduled one or two hours before real time (as it is the case in many EU power markets). More frequent and shorter scheduling intervals for energy transactions may assist in the large-scale integration of intermittent generation. If the scheduling intervals are reduced (for example, providing intraday markets to adjust previous positions in day-ahead markets and closer to real time balancing markets), this will help to reduce the forecast errors of wind or solar power that affect operating reserves.

Given the strong level of presence of wind or solar generation in some power systems, there should be a level playing field for balancing responsibility, which applies to all producers, including wind and solar generators (although perhaps with some less stringent requirements) in order to stimulate all market participants to carry out thorough and proper scheduling and forecasting and thus limit system costs.

In summary, the virtuous combination of adequate available transmission capacity, larger balancing areas and frequent scheduling (within and between areas) may significantly reduce the variability impact of generation and demand, increase predictability and therefore reduce the need for additional flexible resources in power systems with large penetration of intermittent renewable generation. Consequently, the need for ancillary services would be less, and the costs of running the power system would be lower. As an example that this can be accomplished, mandatory Framework

[22] For instance, in the US, New York, New England, and Texas are each tightly integrated and have one balancing authority each, while Arkansas and Arizona each have eight and Florida has eleven (MIT, 2011).

Guidelines has been recently adopted in the European Union with some of the necessary components: A pan-European intra-day platform to enable market participants to trade energy as close to real-time as possible to rebalance their positions, with the participation of the system operators to facilitate an efficient and reliable use of the transmission network capacity in a coordinated way, see ACER (2011). A similar approach is proposed in NERC (2009).

5 Key design elements for grid regulation[23]

The distribution and transmission networks will have to adapt to the new situation so that the revolution towards a sustainable low-carbon energy model can take place.

Transmission and distribution networks have to be separately considered, since their functions and the challenges they will have to face are so different.

5.1 Transmission policy

The increasingly new role of transmission networks will include reaching to those places where the best large renewable resources are located, enlarging the footprint of VER – therefore increasing their economic value and their contribution to the reliability of the power system –, and permitting the integration of otherwise quasi independent electricity markets.

There are some unrelenting transmission policy issues, which will become more acute under the new conditions. If very large amounts of power have to be transported from distant places (offshore wind production from the North Sea, solar power from Northern Africa to Europe, large wind resources from the sparsely populated Mid-West in the USA) and very broad market integration is an objective, then just reinforcements of the existing high voltage grid (400 and 220 kV in Europe) may not be sufficient and some sort of overlay or supergrid will have to be built, perhaps using higher voltage levels and direct current (DC) technology.

5.1.1 Policy and institutional framework

- How to reconcile wide interconnection interests (EU or USA in scope, for instance) with national or local interests?
- How will these decisions be made, both *by whom* (some planning authority with such a wide reach) and *how* (a method that can cope with a problem of such a huge dimensionality and uncertainty)?

5.1.2 Novel technologies

Another open issue is the best use of existing or novel technologies to minimize the environmental impacts and to make maximum use of the existing or future transmission capacity: gas insulated cables, superconductors, low sag conductors, phase measurements, wide area monitoring, flexible alternating current transmission systems (FACTS), etc.

5.1.3 Cross-border interconnections

Transmission networks and flows will crisscross interconnected power systems, where some agents, companies, states or entire countries will benefit clearly from these flows while others will not obtain much benefit from the lines sited in their territories.

- Should the cost of these lines be socialized or should these costs rather be allocated to the beneficiaries of the transmission facilities?
- How can the benefits and beneficiaries be identified in an objective way?

[23] The discussion developed in this section can be found in the work develop by Pérez-Arriaga et al. (2012), researchers from Comillas University.

- How to make whole and minimize the hostility of those who do not benefit from the installation of transmission facilities in their vicinity?
- How to address the coordination of the operation of large interconnected power systems?

5.1.4 Transmission planning

Given the large uncertainty and the diversity of interests that exist in the expansion of the transmission network:

- Should all decisions be left to a central planner under a regulated monopoly scheme or other business models with more participation of stakeholders are also possible?

5.2 Distribution policy

Integration of renewable generators is together with many other relevant ones (e.g. higher efficiency in energy consumption in homes and commercial buildings or deployment of future plug-in electric vehicles) is a driver demanding a profound transformation on the way electricity distribution grids are designed and operated. This transformation needs to result in an enhanced distribution grid, more sophisticated and complex than the actual.

Present distribution electricity grids have been designed to carry electricity from the meshed transmission grid, where most of the generation resources were connected, to final electricity consumers. Distribution grids are characterized by one-direction flows from sources to loads, radial structure, simple operation rules and acceptable reliability of supply. Planning and operation of distribution grids are based on "fit and forget" practices. Distribution grids are presently planned to supply the future peak demand with ample design margins. And they are operated in a passive mode, meaning that once the distribution grid facilities have been installed, for the most part, medium – several kilovolts – and low voltage grids are not monitored or controlled in real time. Customer meters are used for energy settlement and commercial services, but not for network operation. Automatic control systems almost do not exist and grid operators are mainly focussed on ensuring continuity of supply and reconnecting affected customers in case of grid failures or maintenance works.

However, much of the expected volume of electricity production with renewables will be connected in distribution networks, either in low voltage (small wind, roof-top solar panels), or in medium and high voltage distribution. This will force distribution utilities to change the customary procedures for design and operation and, in most cases, to incur in additional costs. Distribution is treated as a regulated monopoly worldwide, although it has been always difficult to determine the adequate level of remuneration and the proper incentives to promote reduction in losses and an optimal level of quality of service. This will become much more challenging with significant amounts of distributed generation, signaling the need for advanced network models and an in-depth revision of the remuneration procedures, as OFGEM is presently doing in the UK, see (OFGEM, 2010). There is the need, again, of an in-depth revision of the regulation of the distribution activity. In this case to assign roles to distributors, retailers and energy service companies on who is doing what in metering, aggregation of consumers, relationship with the distribution system operator, interaction with the end-consumers and control of their appliances, as well as improving the models of remuneration while taking into account quality of supply.

5.2.1 Smart grids

Both in the technical literature and in the non-specialized media the term "smart grid" is frequently used suggesting a radical departure from the present transmission and distribution networks. Smart grid is a loosely defined concept, which includes a diversity of technologies and innovations. The

European Union Smart Grids Platform[24] defines smart grids as “electricity networks that can intelligently integrate the actions of all the users connected to them – generators, consumers, and those that do both – in order to efficiently deliver sustainable, economic and secure electricity supplies”. The USA Energy Independence Security Act of 2007 provides a very comprehensive definition.

The transition from the present electricity grids to transmission and distribution networks with enhanced capabilities requires very significant volumes of investment in new facilities as well as in innovation efforts. Most of them are mainly related to the implementation of much more complex and sophisticated information, communication, and control systems. In addition, investment in grid infrastructure will be also needed to replace old assets, to increase network redundancy and to connect new generation sites and demand users. Finally, operational and maintenance costs should be re-evaluated taking into account the new structure and functionalities provided by smart grids.

Existing electricity grids are already smart. But they need to become much smarter to cope with the new realities of a much more complex, decentralized and interactive power sector, in its way to facilitate an efficient, reliable and carbon-free electric supply. It will be a long, evolutionary process that will use and expand existing network capabilities and add new ones. The design and implementation of adequate regulation at both distribution and transmission levels will be essential in guiding the financial resources and technical capabilities of the private firms towards this common objective.

5.2.2 Grid charges

As argued by Cossent et al (2009), a correct design of grid regulation, in particular use-of-system charges and connection charges for distribution systems are key elements for the large-scale deployment of RES-E in a fair and non-discriminatory way. Other important topic is the use of nodal or zonal pricing, discussed in section 5.

Only a few countries employ use-of-system charges for RES-E, although this would clearly be a good option for regulating correctly the way they are deployed and operated. All use connection charges.

Most countries in Europe use shallow connection charges (by which the RES-E plant only pays for the direct cost of connection), and only some (Spain and the Netherlands) use deep connection charges, by which plants must pay all the cost of connection, including upstream grid reinforcements. The choice between these two options has to strike a balance between providing incentives for deployment, particularly for small-sized operators, and incentivising an optimal and cost-reflective siting of new generation.

Another important issue is whether the DSO is the one determining the total cost of connection. If connection charges are not published ex-ante, this may create disadvantages for RES-E developers in the negotiations with DSOs. Under the current system, DSOs do not have clear incentives for the integration of RES-E, except for low-penetration situations and for low concentration of RES-E plants. Higher penetrations typically result in negative impacts for DSO benefits, mostly due to the need for network investments, which may not be adequately paid for. DSOs are therefore reluctant to facilitate connections.

A way to balance all these considerations would be to promote regulations in which connection charges for RES-E are averaged, regulated, and shallow. And then to socialize the rest of the reinforcement costs, recovering them through use-of-system tariffs. Cossent et al (2009) also recommend to implement incentive-based regulation for DSOs in order to strengthen the incentives for an efficient integration of RES-E.

[24] See http://www.smartgrids.eu/

6 Recommendations for the design of electricity markets and grid regulation

We now try to formulate some general recommendations for the design of electricity markets and grid regulation. Of course, these recommendations must be based on the relevance of their interactions with a large deployment of RES-E. Therefore, first we need to summarize the major conclusions extracted from the assessment performed in Task 5.2.

A first interesting result is that, given a certain amount of RES penetration, impacts do not depend much on the policy instrument chosen. Although the choice of policy instrument will of course have an influence on the amount of RES, and also on the share of the different technologies and their location, most of the impacts depend mostly on:

- the total amount of RES deployed
- the availability of the grid infrastructure

Even when there are some differences between instruments, these are not due to the instrument itself, but to its design elements (e.g., the stability of the regulation, whether the support is technology neutral or technology specific, the harmonized or national character of the policy, etc.).

In fact, most of the differences between policy pathways result from their dependence on the grid. Thus, those pathways that result in a more even development of renewables across Europe (NATFIP, HARMFIT) depend less on the development of the grid, since the compensatory effects of the network are less critical. Instead, for HARMQUO, the effects of the grid expansion are more important.

Other than that, and for all the policy pathways assessed, the results we have obtained confirm many of the results derived from the literature, although with some particularities:

- A significant price decrease effect: average wholesale prices in Europe are expected to be 30% lower in 2030 compared to the no-RES policy scenario. The price level would be only slightly above today's values. However, it is not clear whether this effect is derived from an increased RES penetration or from the increased capacity that accompanies it. Capacities were taken from the Primes High-RES scenario. Modeling results showed that this leads to sufficient or even overcapacity across Europe.
- Price volatility also increases with RES penetration. In general this effect is dampened with grid reinforcement. Without grid reinforcement price volatility will increase even in the no-RES policy scenario. This increase is however much higher when the grid is reinforced, since then the no policy scenario results in lower price volatility in 2030. When there are grid limitations, increased RES do not result in volatilities much higher than the no policy scenario.
- Negative prices appear more frequently in 2030 when RES are strongly developed. The exact amount differs: with the PowerAce model we find 10% of the hours, whereas for the ROM model (used only for Spain) zero-price hours increase up to 40-50% of the year. That shows the strong impact of the grid and system connections. As would be expected then, grid reinforcement also dampens the number of hours with negative prices.
- The impact of RES on generation adequacy depends on the degree of market and network integration. When there is little European integration, some countries will suffer from a significant loss of adequacy in their systems (increased loss of load probability). However, when systems are well integrated this risk is very much reduced.
- In both cases additional capacity will be required to back-up RES, what raises the issue of whether this capacity will come online if prices are depressed (and therefore the investment signal is reduced). Currently, the European electricity market is characterized by a situation of overcapacity, so this should not be an issue in the medium term, and will any-

way depend on the strength of the incentive for new investments (be them in the generation or demand side).

- Balancing needs significantly increase under strong RES support. Upward regulation grows almost 50%, whereas downward regulation increases 200% (basically to prevent spilling RES).
- However, the costs of these balancing services need not increase, depending on the system. In the exercise run in Spain, with significant overcapacity and a large share of hydro, balancing costs actually decrease. These costs will depend strongly on the conventional generation mix considered in the analysis.
- Finally, regarding the cost of grid expansion, our results for Southwest Europe show that these costs will depend on three major factors: the amount of RES incorporated, its location, and its market value. In general the calculated grid extension costs are rather low compared to RES generation costs (e.g. for Southwest Europe in the range of 1.7 to 2.5 €/MWh related to RES generation). Here the choice of policy instrument does create a small difference: for example, a harmonized quota system would probably induce RES to be installed where its market value is higher (closer to the load) and this would result in lower network costs (lower even than under a no policy scenario). Under a feed-in-tariff this may not be the case and network costs may increase.

All these results show that there will be significant impacts on electricity markets and grids, and that is therefore a need to change the way they are designed if we are to accommodate more RES.

Below we provide some recommendations based both in the modeling and the extensive literature review:

- The first priority for electricity markets and grid regulation should be to deploy the investments required in the network. Substantial internal and cross-border grid investments are needed to mitigate the impacts of RES-E on prices or generation adequacy, which requires sufficient investment signals. Current regulations should be adapted if the foreseen extensions (TYNDP) could not be realized.
- In addition, and related to this, improved cross-border transmission policies will facilitate the efficient operation of the grid under increased RES penetration. Also nodal prices might be an instrument to improve grid investment and operation decisions.
- The costs and need for balancing can be reduced by more frequent and shorter scheduling intervals. Balancing markets should be made more flexible so that renewables and demand side sources can participate more easily. The coordination of balancing areas is also important to reduce balancing costs.
- Increased RES penetration leads to an augmented need for flexibility in system operation. Therefore, incentives for demand response or other flexibility options could be considered after an in-depth analysis of all their strengths and weaknesses.
- Pricing and bidding rules in electricity markets should be analyzed in detail. Possibly, complex instead of simple bids could be beneficial for systems with a high renewables penetration. Also, joint bids for energy production and balancing services could be useful. Non-discriminatory pricing could be used to internalize non-convex-cost related components of the actual value of electricity market prices.
- Finally, it should be taken into account that priority of dispatch amplifies the merit-order or negative prices effect (and with them the impacts on the market value of renewables). Given also that priority of dispatch for renewables may also increase the cost of the system (because of the lack of flexibility of the thermal fleet), rules for priority dispatch should be carefully considered to minimise these impacts.

Therefore, we can see that significant changes may be required in the design of electricity markets and grid regulation in order to accommodate a growing share of RES-E. Moreover, given that many of these changes will also benefit the rest of the system (e.g., by providing a more flexible and wider network), they should be addressed as soon as possible.

7 References

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