Dialogue on a RES policy framework for 2030

towards2030

D5.1 Report

Electricity markets and RES integration – Key challenges and possible solutions

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About the project

The aim of **towards2030-*dialogue*** is to facilitate and guide the RES policy dialogue for the period towards 2030. This strategic initiative aims for an intense stakeholder dialogue that establishes a European vision of a joint future RES policy framework.

The dialogue process will be coupled with in-depth and continuous analysis of relevant topics that include RES in all energy sectors but with more detailed analyses for renewable electricity. The work will be based on results from the IEE project beyond 2020 (www.res-policy-beyond2020.eu), where policy pathways with different degrees of harmonisation have been analysed for the post 2020 period. **towards2030-*dialogue*** will directly build on these outcomes: complement, adapt and extend the assessment to the evolving policy process in Europe. The added value of **towards2030-*dialogue*** includes the analysis of alternative policy pathways for 2030, such as the (partial) opening of national support schemes, the clustering of regional support schemes as well as options to coordinate and align national schemes. Additionally, this project offers also an impact assessment of different target setting options for 2030, discussing advanced concepts for related effort sharing.

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Executive summary

As the share of intermittent RES (such as wind turbines and solar PV) increases significantly, their deployment challenges the operation of power system, and impacts the role played by electricity markets that have not been designed to handle the features of intermittent RES. First of all, intermittent RES feature a variable output that depends on the availability of the resources they are based on. This variability is worsened by the low-marginal costs of intermittent RES. RES are willing to produce whenever they can, but only when they can. Second, this output is also difficult to predict accurately. Third, the best generation sites for intermittent RES such as wind turbines are often located far away from consumption centres, creating the need for significant investment in the transmission system. On the opposite, some resources like solar PV are mostly integrated to the distribution level, creating new kinds of flows from low-voltage level to high-voltage level. Fourth, the development of intermittent RES is still driven by support mechanisms and isolated from most market-signals.

It is therefore clear that electricity market design must be revamped to integrate intermittent RES. On the one hand, electricity markets must cope with the changes in power systems operation that are created by the deployment of intermittent RES: new time-definitions must fit RES variability, the day-ahead horizon is not adapted to RES predictability, existing zones do not reflect the congestion patterns corresponding to the location of intermittent RES. On the other hand, intermittent RES cannot remain at the margin of power systems, and must be more closely integrated into electricity markets.

In this report we identify four key challenges for electricity market design in the context of RES integration. First, there is a need to ensure resources adequacy in the long-term. This challenge emerged as the profits of conventional generation assets have eroded under the pressure of intermittent RES with "zero" marginal-costs. It is then not guaranteed that the assets being decommissioned will be replaced, especially as the deployment of RES is driven by uncertain support policies rather than market-signals. Second, it is crucial that the flexible resources required to cope with RES variability are in place and incentivised to operate flexibly. Third, electricity market design must ensure efficient expansion of the transmission and distribution network, as significant investments are needed to connect intermittent RES. This challenge is made more difficult by the lack of coordination between network investments and generation investments, especially when the generation investments are driven by uncertain policies. Fourth, while the traditional organisation of power systems was based on a centralised operation of a set of large plants adjusting their production to follow load variations, system operation at the distribution level will be increasingly challenging with the development of distributed resources. The causality relationship between the features of intermittent RES and the four key challenges are illustrated in Figure 1.

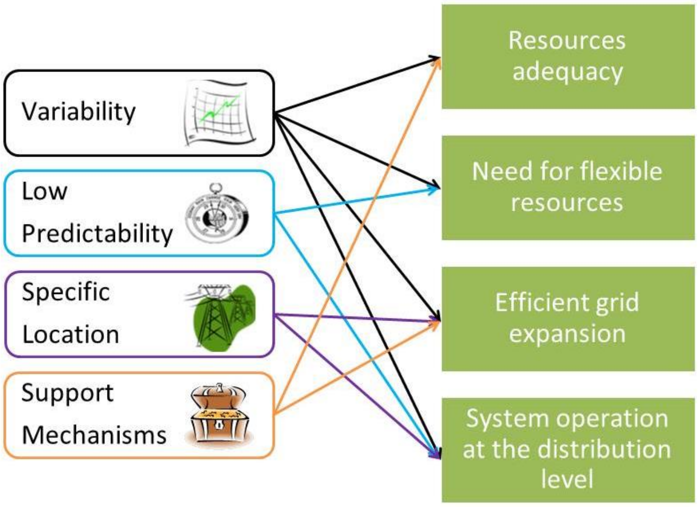

Figure 1 **Causality relationship between RES features and key challenges for electricity markets. Own depiction.**

In the last session of the report, we describe three toolboxes of market design element that could contribute to solving the four main challenges: the wholesale market design, additional coordination tools, and solutions based on the deployment of distributed resources.

Evolutions of the wholesale market design have two facets. First, the integration of intermittent RES must evolve as they get deployed. We show that the only obstacle to 'melting-pot integration' (i.e. with a single set of rules common to all resources) is the absence of dynamic retail pricing. However, once this shortcoming will have been solved, melting-pot integration should ensure efficient integration of intermittent RES. The second facet of wholesale market design relates to the evolutions required to manage the power system efficiently when this power system features a high share of intermittent RES. This report details the evolutions required: shorter-time units will be needed to reflect the variability introduced by intermittent RES and remunerate flexible resources adequately; refined and dynamic space-units could help tackling efficiently the grid expansion challenge; higher differentials between extreme prices would be needed to reflect the value of energy at times of scarcity or abundance and encourage the development of flexible resources; the consistency between the different markets from day-ahead to real-time should be improved to match the needs of intermittent RES that are poorly predictable. Obviously, these evolutions will not be easy to implement and they might have negative secondary effects. Non-convexities of thermal generators might be more difficult to handle with shorter time-units, while redefining space-units would have significant redistribution effects that could lead to acceptability issues. Finally, we would have a high number of products as a result of smaller time and space units in a set of parallel markets (day-ahead, intraday, real-time and reserves markets), which could be a source of liquidity and complexity issues.

An alternative (and/or complement) to wholesale market evolutions is the implementation of a set of coordination tools to ensure efficient investment and operation in power systems featuring a high share of intermittent RES. Generation adequacy policies might be implemented to coordinate the development of generation (or demand-response) assets and solve the resources adequacy issue. However, our analysis reveals that this would imply the development of national rather than European approaches to generation adequacy, with consequences on the provision of flexibility. The coordination between network investment and operation at the regional scale might require specific tools, such as a European system-management layer, as well as planning at the regional scale and cost-allocation tools. Coordination between network and generation investment to ensure efficient expansion of the grid can be ensured via the development of market facilitators, reforming the payments by generators, and changing the response of TSOs to connection requests and investments need.

Finally, coordination of investment and operation between transmission network operators and distribution network operators will be required to manage efficiently operation at the distribution level.

The last toolbox focuses on tools required to unlock the potential of distributed resources. Indeed, these resources can provide many different flexibility services, contribute to resources adequacy, allow deferral of network expansion, and are needed to manage actively the system at the distribution level. However, an efficient development and management of distributed resources will only be possible provided a compatible framework is implemented. The contracts offered by suppliers to their customers and the retail market design must evolve to allow consumers expressing their willingness to pay for electricity and valuing their flexibility. Similarly, in order to develop a contribution of distributed resources to efficient grid expansion and management, network tariffs should be revamped to reflect the state of the distribution network and the contribution of a certain consumer to local losses and peaks in the distribution network. A wide set of contracts and intermediaries proposing the contracts to consumers would also be needed to tap the full potential of demand-response by consumers who differ widely in terms of technical potential and preferences. Finally, the role of DSOs will have to be revisited. A sound regulation must be established to deliver efficient incentives to the DSOs. Whether new services (e.g. ownership and management of metering systems and charging infrastructures, data handling, energy efficiency and flexibility provision) will be provided by the DSOs or by third-parties, there will be a need for stricter unbundling and transparency requirements as DSOs handle more responsibilities.

These three toolboxes are partial substitutes and complements, but a mix of these tools must be picked and implemented to address the key challenges of RES integration for electricity market design. A consistent vision must be developed to solve these challenges.

1 Introduction: Intermittent RES features and market integration

1.1 Features specific to intermittent RES

Power systems were conceived on a set of paradigms that reflected the technical options available then. In particular they were based on a set of large controllable plants at the transmission level that are dispatched centrally to match the variations of an inelastic load. Electricity markets were then introduced to provide the short-term and long-term signals required to coordinate a set of competitive actors and ensure optimal dispatch and investment in generation assets. The design of electricity markets was logically adapted to the features of power systems by then. However, the features of intermittent[1] RES that are introduced in power systems today are very different from the ones of a typical combined cycle gas turbine. In order to understand the challenges for electricity markets and RES integration, it is necessary to understand how intermittent[2] RES differ from the more traditional power plants.

1.1.1 Variable output

The output of intermittent RES is variable for two main reasons. First, the output of wind turbines and solar PV depends on the availability of the resources they are based on: wind doesn't always blow, Sun doesn't always shine. Second, these units feature very low ("zero") marginal costs and there is hence a strong rationale for these units to generate cheap energy when possible. In other words, intermittent RES are willing to generate whenever they can, but only when they can.

These fluctuations are seasonal, daily, hourly, or minute-by-minute, with different consequences on power systems and power markets.

Long-term variability results from climatic seasonal effects. The output from solar-based resources will for instance typically be lower in the winter. While such variations do not constitute a challenge for the operation of power systems in the short-term, it implies that some plants will then be needed as back-up, while running only part of the year. Long periods of time with low wind output will also occur at a relatively high frequency at a country-scale, with consequences on the economics of energy storage and power systems in general (Plötz and Michaelis).

Very short-term fluctuations occurring within seconds do not constitute a major challenge for power system operations used to handling load fast variability, as these fluctuations tend to average out when the penetration of intermittent RES increases. However, variations that occur over longer time-scale (from several minutes to several hours) can be more problematic. With high penetrations of wind, these variations can become quite significant. In the whole Denmark, maximum upwards and downwards variations of wind output (for more than a hundred sites) were estimated by Holttinen et al. (2009) to roughly 20% of total installed capacity within an hour, 50% of total installed capacity within four hours, and 80% of total installed capacity within 12 hours. Similarly, Bertsch et al. (2013) estimated that by 2050 Germany and Great-Britain could face hourly variations of the output of intermittent RES of respectively 20 GW and 40 GW. This has important consequences on the

[1] The term "variable" is sometimes deemed more adequate to designate the wind and solar power technologies, as these resources rarely switch-on and off completely. Yet, we will conserve in this study the word "intermittent" that is more commonly employed. Of course, not all RES are intermittent: one can for instance think of hydropower and biomass. However, it is likely that wind and solar power technologies will constitute the bulk of RES development by 2030.

need for back-up flexible resources (on generation or demand-side) to be able to ramp-up and down when needed.

This variability can be mitigated by smoothing factors such as geographical spread or technological spread (which explain for instance the significantly higher variations for the UK in the study of Bertsch et al. (2013)). Even in a small power system like Denmark, there are stability gains at the system level compared to the unit level (Holttinen et al., 2009). However there is a limit to the benefits of geographical spread. First, extreme weather events occur on large geographical scales: a study by Pöyry (2013) for instance emphasizes the fact that residual loads (i.e. consumption minus output of intermittent RES) are partially correlated even in distant power systems. Second, making the most of geographical aggregation requires a supra-national approach to generation adequacy that is for instance missing today in Europe (Henriot and Glachant, 2014).

1.1.2 Low predictable output

The output of most intermittent RES depends on complex meteorological phenomena, some of which are very difficult to predict (e.g. cloudiness for solar PV, phase changes for wind). As a consequence, it is difficult to predict precisely what will be the output of intermittent RES. Forecasts are based on a mix of physical models and statistical models that are constantly improving as experience with intermittent RES is gained. However, it is still impossible to predict accurately the output of intermittent RES in the short-term, as illustrated in Figure 2.

While system operators are used to deal with uncertainty related to load forecast errors, Maupas (2008) argues that load is easier to predict: the day-ahead Mean Square error of load in the French system was for instance equal to 1% of peak demand in the winter 2007, significantly less than the numbers presented in Figure 2 for wind forecast errors.

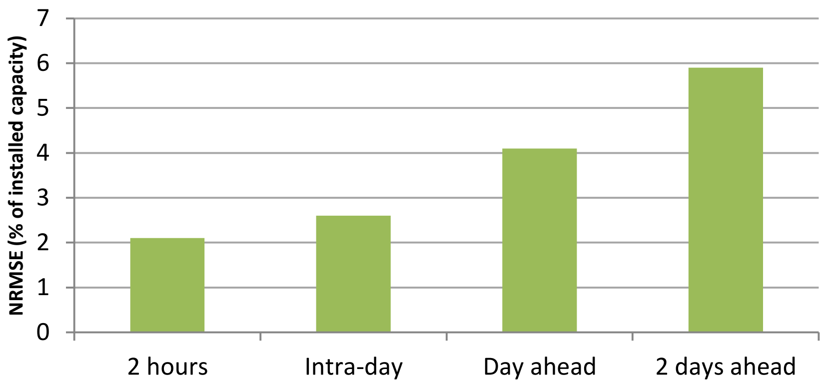

Figure 2 **Wind power forecast error with increasing forecast horizon (2009 average value in Germany, from Tambke as quoted by EWEA (2010))**

1.1.3 Location

The best generation sites (in terms of output/unit installed) for wind turbines are located at very specific location, often far from the consumption centres: this is for instance the case of wind farms in Scotland or in the north of Germany. Similarly, the output of PV varies a lot with latitude. A further difficulty comes from the fact that land-intensive renewables (like wind farms) cannot be installed in places where land is expensive, which is typically the case close to consumption centres. As long as intermittent RES do not receive locational signals, they therefore tend to pick generation sites that require significant investment in the transmission network. According to the Ten-Year Network Development Plan (ENTSO-E, 2012), 80% of the projects of common interests are required to solve directly or indirectly bottlenecks created by intermittent RES.

In parallel to these large developments taking place at a great distance from load, a significant share of intermittent RES is now installed at the distribution level. This creates flows from low-voltage level to high-voltage level, requiring more active system management at the distribution level (Trebolle, 2013).

1.1.4 Development driven by support mechanisms

Finally, in addition to these technical features of intermittent RES, it is important to keep in mind that the significant development of intermittent RES in Europe has been made possible thanks to strong support mechanisms. While this support can be justified by a wide range of positive externalities of intermittent RES, it has resulted in a development of RES being disconnected from market prices. As this support and the impact on electricity bills have been increasingly contested, especially at times of financial difficulties, RES policies are highly uncertain today. Further development of intermittent RES, and the related impact on market prices and load-factors of all generation assets, will probably be the result of targets, quotas, and regulated tariffs that are set politically.

1.2 The concept of RES market integration

The specificities of RES that are described in section 1 challenge the functioning of power systems. It is clear that, as they develop significantly, these resources cannot remain at the margin of power systems. As put very clearly by Pérez-Arriaga (2012): “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 intermittent generation has to be profoundly reconsidered […]. Second, wind and solar PV plants can no longer be regarded as passive units […]. These features are considered essential for the future integration of high wind penetration in electric power systems.” Integration of RES into electricity markets is therefore a two-fold challenge. First, electricity markets must be redesigned to handle resources that are more variable, unpredictable, and located at specific generation sites. Second, RES cannot be kept out of power markets that were conceived as the main driver of operation and investment in liberalised power systems.

The need to adapt electricity markets design and integrate intermittent RES is of course associated to a series of challenges, both to ensure adequate and efficient investment in generation and transmission assets (as described in section 2.1), and to ensure safe and efficient operation of power systems (as described in section 2.2). But the potential of solving technical issues by implementing the right economic incentives also make market design a source of solutions for accommodating large shares of intermittent RES into power systems, as described in section 3.

2 Challenges for electricity market design and RES integration towards 2030

2.1 Key challenges: Unlocking investment

2.1.1 An issue of "missing money"

2.1.1.1 Generation assets

As explained in section 1.1.1, intermittent RES feature very low variable costs. They are therefore the first resources dispatched when available. This effect, often referred to as the "merit-order effect", has for instance been described by Sensfuss et al. (2008) and is illustrated in Figure 3. It has two consequences on other generators. First, the most expensive units are dispatched less often as their bids are pushed by intermittent RES out of the market. Second, prices are lower on average, as the price in a competitive energy market is set by the marginal costs of the most expensive unit dispatched. The merit-order effect associated to the strong growth of intermittent RES has therefore reduced the profits of conventional generators that run less often and get lower wholesale prices on average. Under these circumstances, conventional generators are struggling to achieve break-even. An article published in The Economist on 12th October 2013 highlighted the fact that the top 20 energy utilities in Europe had lost half their market value between 2008 and 2013, as wholesale prices in Germany were going down from 80 €/MWh to 38 €/MWh. E.ON and RWE had lost one third of their income since 2010 and 30-40% of RWE's conventional power stations were losing money at that time (The Economist, 2013).

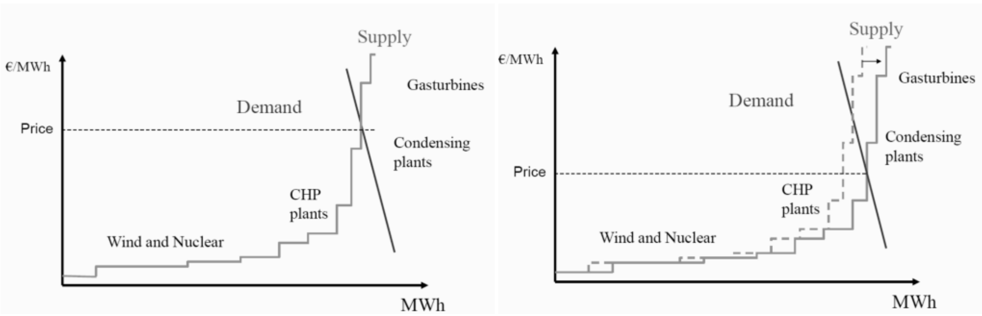

Figure 3 **Merit-Order and Prices in a generic electricity market, with low wind output (left figure) compared to high wind output (right figure). Source: Morthorst (2008)**

It is important to specify that RES are not the only responsible of the financial difficulties of conventional power units. The Economist (2013) also emphasises the fact that utilities overinvested during the 2000s and were then caught back by the financial crisis hit on electricity consumption. This is illustrated in some calculations realised by Rüdinger et al. (2014) illustrated in Figure 4. If demand for electricity in Europe had followed the pre-crisis trend (2000-2008) up to 2012, the total increase between 2000 and 2012 would have reached 550 TWh compared to the actual 267 TWh increase. Across the same period, the development of intermittent RES followed the trajectory planned and added additional generation of 350 TWh, while increase of the fossil fuel capacity accounted for a potential production of 280 TWh. These results show that RES alone (i.e. without the crisis and without overinvestment in conventional capacity) would not have led to the significant overcapacity we observe today.

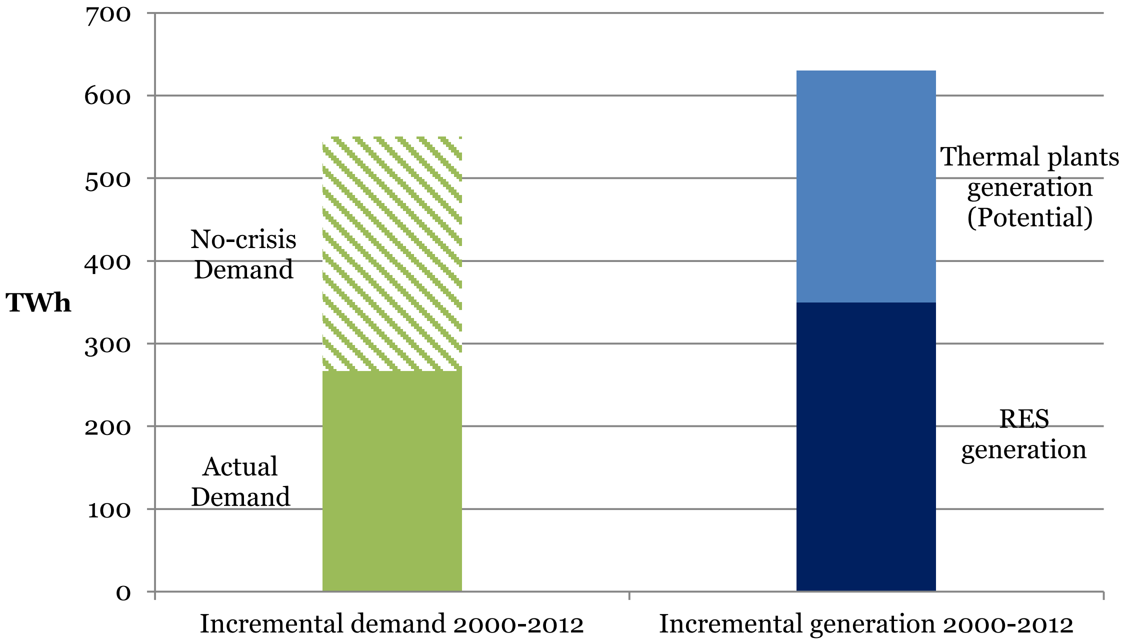

Figure 4 **Incremental electricity demand 2000-2012, with and without crisis, versus incremental renewable and fossil fuel capacity (potential generation based on a conservative 40% load-factor). Source: own depiction based on Rüdinger et al. 2014**

However, the current situation is unstable. In an energy-only market with a large share of intermittent RES, the revenues of conventional generation assets (that could still be needed as back-up when the variable output of intermittent RES is low) depend increasingly on high prices at times of relative scarcity. It does not mean that a new equilibrium of generation entry cannot be found, as discussed further in section 3.1. Yet, there are several challenges that must be solved to ensure a decarbonisation of the energy mix and generation adequacy.

While we are in a situation of overcapacity today in Europe (THEMA consulting group, 2013), it is not clear whether investment in generation assets will remain sufficient in the future. Indeed, many generation assets are ageing or must be decommissioned, such as for instance high-emission coal power plants under the Large Combustion Plant Directive, or nuclear power plants in Germany. Will a revenue stream based on a small number of uncertain energy peak prices be attractive enough to investors? Will these high prices be politically accepted? At the same time, we have targets for high share of intermittent RES in the generation mix by 2030, which raises two further questions. How to reach market equilibrium when a significant share of the mix is pushed by support policies? And how to make sure that these RES targets will be reached if there is a move towards more market-based support to intermittent RES?

2.1.1.2 Transmission & distribution assets

The need for investment in the power sector is not limited to generation assets. Significant investment will also be required in the transmission and the distribution network both to replace ageing assets and to accommodate new flows created by resources that are located at very specific locations (See section 1.1.3). Estimates of the required capital expenditures are presented in Table 1. These figures represent a significant increase compared to capital expenditures observed in the last decade (Roland Berger, 2011). Intermittent RES are not the only source of needs for investment, but they account for a significant share of the planned expansion of the grid. The Ten-Year Network Development Plan established by the ENTSO-E claims that 80% of the Projects of Common Interests listed in this document are needed to solve bottlenecks created directly or indirectly by intermittent RES. Transmission investments are also required to make the most of the geographical and technological spread described in section 1.1.1.

Table 1 **Investment requirements in electricity T&D networks by 2030.Source: IEA (2014b),ENTSO-E (2014),European Commission (2011)**

Source		Time period	Perimeter	Transmission grid	Distribution grid
ENTSO-E	*TYNDP 2014*	2014-2030	ENTSO-E	110-150 billion *€14*	N.A.
European Commission	*Impact Assessment Energy Roadmap 2050*	2011-2030	European Union	113.5 billion *€05*	507.2 billion *€05*
IEA	*World Energy Investment Outlook 2014*	2014-2030	European Union	114 billion *$12*	398 billion *$12*

Most of these investments are realised by regulated transmission and distribution network operators that receive a guaranteed return on their asset base. However, this is not sufficient to guarantee that such volumes of investment will be achievable. As transmission system operators traditionally finance their capital expenditures by emitting debt, the gearing of these companies is already high today. The increase in tariffs that would be required for TSOs to achieve such levels of investment without losing their investment grade (and therefore without losing access to low interest rates) might not be accepted by consumers. Investment in the network would then not be financially sustainable in the long-term (Henriot, 2013).

This is especially true as a significant share of the transmission tariffs is based on the net energy consumption that could stagnate as consumers install more distributed energy resources. In other words, while the needs for investment are proportionate to capacity (and hence maximum consumption), the revenues are partly based on the energy transmitted (and hence net average consumption), which will grow much slower as distributed resources with low load factors and variable production get installed. In extreme cases, consumers could have incentives to leave the grid as distributed resources get cheaper and grid-parity is reached, further increasing the tariffs for remaining consumers, and creating a dynamic process that would leave the grid operators with stranded assets.[3] It is therefore crucial to address the question of the remuneration of network infrastructures, despite the fact that they receive a regulated return.

2.1.2 An issue of missing planning

2.1.2.1 The impact of uncertain policies

As mentioned in section 1.1.4, the development of intermittent RES in Europe has been made possible by a wide range of support schemes.[4] However, the modifications of these schemes have generated a high uncertainty both for intermittent RES (whose return directly depends on these schemes), and for conventional generators (whose value is impacted by the development of additional RES capacity). The fact that the implementation of capacity remuneration mechanisms is considered in many member states currently facing overcapacity illustrates the instability of a power system whose development is based on uncertain support schemes.

As the costs of intermittent RES have fallen, there have been calls to reform these support schemes. In its guidance for the design of renewable support schemes, the European Commission has for instance emphasized the need to change instruments for more market-based solutions, and argued that "*support levels will decline and eventually be phased-out*" (European Commission, 2013). This is based on the assumption that the high technology learning rates observed both for wind and solar technologies, as capacity is installed, will lead to a point

[3] Such a process has been described in detail in the case of the United States, where it could become economic to defect the grid by 2020 (Rocky Mountain Institute, 2014).

[4] For more details on the different schemes, the reader can report to Batlle et al. (2012)

in which support will not be required anymore to make intermittent RES competitive with conventional technologies. Intermittent RES would then receive their revenue from wholesale energy prices.

An extensive review of the learning rates observed for energy technologies has been made by Junginger et al. (2008). These learning rates[5] are typically between 10% and 30%, as described in Figure 5. However, a second result from the analysis of (Junginger et al.) is also the need to take into consideration other effects that can lead to negative learning rates, such as increasing commodity prices (steel for wind power, and silicon for solar PVs), or disconnection between prices and cost caused by a lack of competition or increasing demand. There are therefore many uncertainties that make it difficult to extrapolate learning curves to forecast RES technology prices.

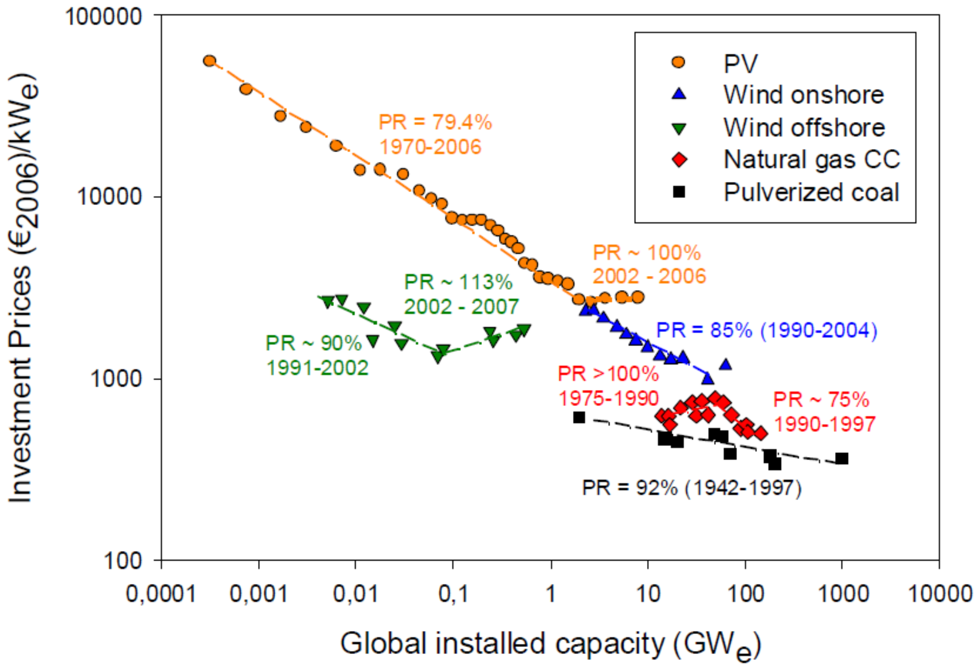

Figure 5 **Historic learning curves and progress rates (PR) of different generation technologies. A PR of X% means that costs are reduced by 1-X% each time the installed capacity doubles. Source: Junginger et al. (2008)**

In addition, there is a risk that the market value of intermittent RES might fall faster than costs. Intermittent RES production is variable, and the profitability of a unit depends on its resource-dependent generation profile and on the wholesale market prices at times when the unit generates (Joskow, 2011). In practice, it means that two units generating the same amount of energy can have very different values for the system, and very different profitability if their returns are based on market prices. Schmalensee (2013) recently showed that for a set of generating units located across the United States, the actual value of wind power was only 88% of what it would have been if produced at average spot prices, while the actual value of solar power was 116% of what it would have been if produced at average spot prices. Of course, the more units installed with a similar profile, the more the merit-order effect (described in section 2.1.1.1) will lead to reduced prices when these units are available, and the lower revenues these units will get from energy markets.[6] A good literature review of what is

[5] The concept of learning rate is based on the observation that there is a logarithmic relationship between the costs of a technology and the cumulative experience of this technology. A theoretical analysis of this concept and a meta-analysis of wind power learning rates can be found in Lindman and Söderholm (2012). In this document, a learning rate of X% (corresponding to a progress rate of 1-X%) means that the installation costs decrease by X% each time the installed capacity doubles.

[6] In this short analysis, we consider that all other capacities remain identical. We will see in section 3.1.1 that conclusions can be different in a dynamic environment.

sometimes referred to as a "*cannibalisation effect*" in a wide range of power systems in Europe and the United States has been published by Hirth (2013), with value factors reaching 0.7 for wind at 30% market share and reaching 0.7 for solar power at 10-15% penetration rates.

It is therefore clear that the existence of a break-even point where the costs of intermittent RES would be low enough to phase-out support schemes depends on a race between learning rates and the cannibalisation effect. To put it simply, the more a certain RES technology is installed, the cheaper it gets but the less value it has. This process has been assessed by Green and Léautier (2014) in the case of the British power system. For learning rates of 19% ('Central scenario'), lower prices resulting from the cannibalisation effect would offset the saving on costs due to learning rates (See Figure 6). Learning rates of 30% ('High scenario') would be required to phase-out support schemes in the long-term, while learning rates of 10% ('Low scenario') would even require higher levels of support. These results might vary across different markets with different resources and generation mix, but the effects of cannibalisation should in any case not be neglected.

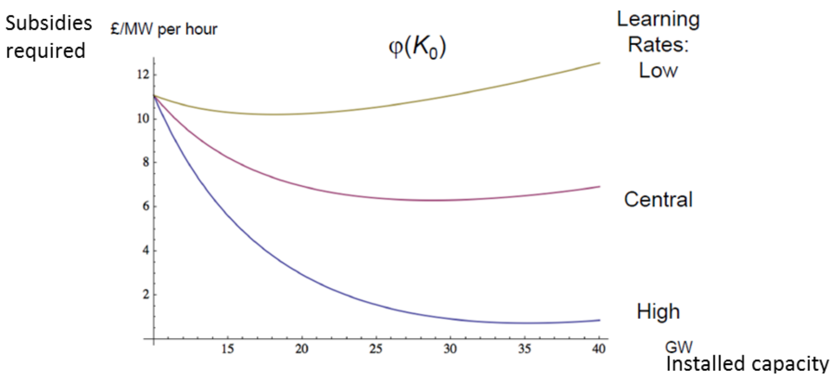

Figure 6 **Support required to install wind power in the UK under different learning rates. Source: Green and Léautier (2014)**

Despite the willingness of the European Commission to phase-out support schemes as soon as possible, it is likely that future power prices will depend on carbon prices, support to RES development, energy efficiency targets that are the result of both national and European political choices. Liberalisation was to substitute the coordination of investment (and operation) within integrated monopolistic companies with a market-based coordination. As a significant share of the investments in European power systems do not depend on market signals, the energy wholesale market cannot fulfil its role of long-term coordination of investment in the current setting. One of the challenges of a power system integrating a high share of intermittent RES benefiting from support schemes is therefore to ensure the development of adequate long-term investment signals.

2.1.2.2 Coordination of transmission with generation assets

Power generation and transmission are complementary activities. Before liberalisation and unbundling of generation and transmission assets, expansion of the transmission and generation system was planned by vertically integrated utilities. The coordination between generation and transmission is now more difficult as the planning of generation, transmission and distribution are independent from one another and result from decisions taken by a multiplicity of actors. Different paradigms have been introduced to solve this issue, from approval by a regulator of transmission reinforcements proposed by the system operator, to merchant lines developed by merchant investors who then collect congestion rents of their lines (Peréz-Arriaga and Olmos, 2006). Yet, the complex task of developing the transmission grid without certainty on the future development of the generation mix becomes even more challenging with the development of intermittent RES.

First of all, as intermittent RES are often located at very specific locations, the joint optimisation of the grid and the generation assets becomes crucial. As explained in section 1.1.3, the best resources are sometimes located far from load centres. There is hence a significant number of trade-offs between better generation sites that are costly to connect to the grid, and sites with a lower output but requiring less grid expansion. At the same time, more actions must be taken at the distribution level to defer grid expansion (Anaya and Pollitt, 2014; EPRI, 2014), which is also a source of further trade-offs between investments in generation and transmission assets.

Second, permitting is a much more complex issue for transmission lines than for generation assets. As a result, it takes on average seven to ten years (and up to twenty years for the most controversial lines) to build a power line compared to two to three years for wind farms and Combined Cycle Gas Turbines (Rious et al., 2011). It means that a reactive TSO that would not anticipate the connection of generators could create a severe delay between the moment when a power plant is operational and the moment when the network upgrade becomes operational. Rious et al. (2011) argues that the solution is a proactive TSO anticipating the future development of the generation mix.

However, there is also increased uncertainty on the evolution of the generation mix as a result of RES development, and hence higher risks of costly anticipation. An idea of the range of possible evolutions can be provided by the four visions of the ENTSO-E introduced in the TYNDP 2014 (ENTSO-E, 2014), from a “Slow Progress” vision featuring a low electricity demand, reinforced national energy politics and slow implementation of the Energy Roadmap 2050, to a “Green revolution” featuring high electricity demand, development of smart-grids, CCS, demand response and electric plug-in vehicles. The needs for infrastructure would of course be quite different under each of these visions. In the current context, the support schemes discussed in section 2.1.2.1 could be the main drivers of the evolution of the generation mix, and hence of the need for expansion of the transmission and distribution grid. Such schemes could also determine whether the targets for RES generation will be reached by developing offshore wind in the North Sea or distributed solar PV, with very different consequences on the required infrastructure. Figure 7 illustrates how the development of wind in Germany has led to a redistribution of physical flows from France to Germany. Indeed, the operational review realised by Coreso (2014) showed that thanks to massive renewable infeed (resulting of support mechanisms), Germany is reinforcing its position of exporting country.

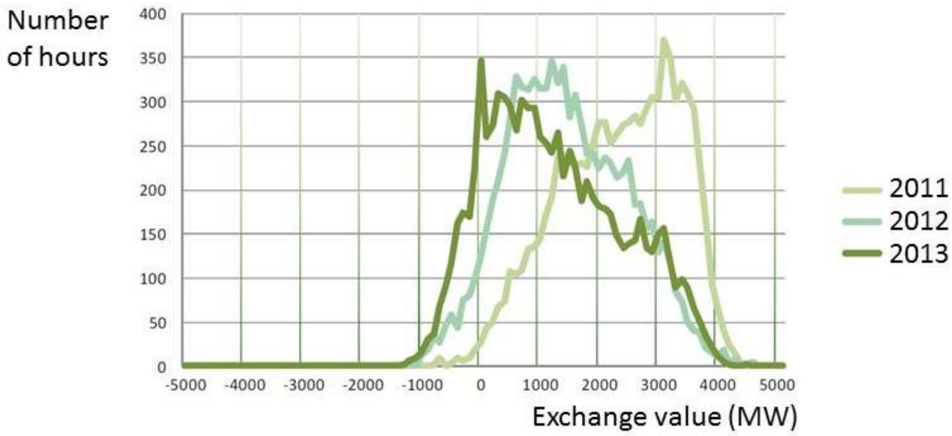

Figure 7 **Statistical distribution of physicals flows from France to Germany. Source: Coreso operational review 2013**

Finally, there is not only a need for intra-TSO network upgrade investments, but also for inter-TSO network upgrade investment, as described by Joskow (2006). The asymmetries between these two kinds of projects can result in inefficiencies, as TSOs first tend to solve internal congestions by pushing congestion to the borders of their control zone, before facilitating trade between the different zones. Saguan and Meeus (2014) illustrate how a national transmission planning can impact the costs of renewable energy, when compared to supranational planning.

2.2 Key challenges: ensuring safe and efficient operation

2.2.1 The need for flexibility

2.2.1.1 Why flexibility is needed

Flexibility is defined here as the ability of a given resource to adjust production or consumption within a given timeframe (regardless of potential variations in RES production). It includes the ability of a power unit to start-up and quickly ramp-up or ramp-down, to cycle frequently, and to operate at low minimum loads. As the output of intermittent RES is variable (See section 1.1.1) and not predictable (See section 1.1.2), an increasing share of intermittent RES leads to higher and new needs for flexibility. Gottstein and Skillings (2012) for instance estimated that the development of intermittent RES in the UK would create a need for 260 start-ups per year for mid-merit CCGTs by 2030, compared to less than 50 per year today. Bertsch et al. (2013) estimated (up and down) hourly changes in residual demand for Great-Britain and Germany by 2050. The first and third quartiles of hourly changes in residual demand, as well as the maximum hourly variations, are represented in the boxplot in Figure 8. Maximum values of hourly load changes double from 2011 to 2050 with a share of intermittent RES in electricity consumption equal to 50%. The UK faces maximum hourly load changes of 40 GW by 2050 with a share of wind power equal to 70% of electricity consumption. It is clear that flexibility will be a prerequisite to generation adequacy (Henriot and Glachant, 2014).

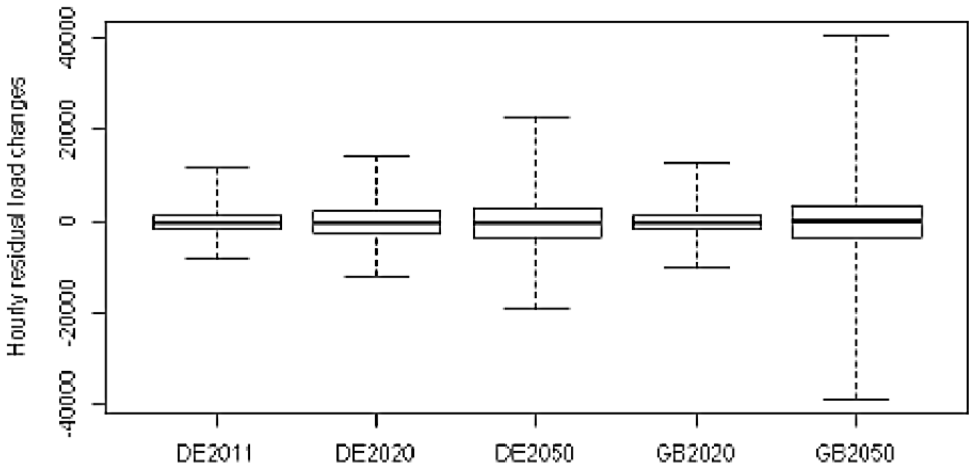

Figure 8 **Hourly changes in residual demand (MW): actual for DE2011 and model simulations for 2020 and 2050 (Bertsch et al. 2013) DE stands for Germany, GB for Great Britain.**

Yet flexibility is costly. Increased cycling leads to higher costs for generators as it increases wear and tear and lower efficiency, while maintenance contracts must be renegotiated to allow for more flexibility (Pérez-Arriaga and Batlle, 2012). As flexibility will be increasingly needed to cope with the variations of intermittent RES in power systems, some market signals will be required to reflect this need for flexibility in power markets and remunerate the flexibility providers.

A further difficulty emerges from the wide range of flexibility needs across the different power systems. In the study of Bertsch et al. (2013), the maximum hourly changes will be twice as large in Great-Britain as in Germany for similar average variations. This can be explained by a higher share of intermittent RES in the UK and a more diversified mix (featuring both solar and wind power) in Germany.

Finally, the maximum needs for flexibility will be far more significant than the average variations (as illustrated for hourly variations in Figure 8). It implies that the capacity to deliver flexibility will face a similar issue of low load-factor as the one described for capacity to deliver energy in section 2.1.1.1. Under the current setting, the revenue stream for flexible capacity will be based on revenues at times of extreme events, and the compatibility of such a revenue stream with the business-model of flexible resources should be assessed.

2.2.1.2 Which flexibility provision?

As the share of intermittent RES in the generation mix and the requirements for flexibility increase, the range of resources that are able to deliver flexibility will also have to evolve. Peaking units that are the most flexible units in current power systems are shut down (in the short-term or the long-term) in response to high RES generation. This is emphasized in a report by ECOFYS (2014) reviewing the different flexibility options that are available in power systems. These options include among others thermal generators, intermittent RES, demand-response and storage facilities, although some economic, technical and political barriers must be taken into account when assessing the potential of each resource (See Table 2). As the future flexibility needs of power systems are very diverse and still not fully identified, it is important not to discriminate any of these resources from flexibility provision.

Table 2 Flexibility resources potential and main barriers. Adapted from ECOFYS (2014)

Technology	Ramping	Cold start	Minimum load	Barriers
Coal	Existing: 1.5%/min New: 6%/min	Existing: 10 hours New: 4 hours	20% - 40%	Lowe efficiency and increasing variable costs when used flexibly
Lignite	Existing: 1%/min New: 4%/min	Existing: 10 hours New: 6 hours		Increased war-and-tear when used flexibly
CCGT	Existing: 2%/min New: 8%/min	Existing: 4 hours New: 2 hours	15% - 50%	High Co2-emissions
OCGT	Existing: 8%/min New: 20%/min	<0.1 hour	20% - 50%	
Nuclear	3.8%/min - 10%/min	Up to two days	20% - 60%	Risks of accident Controversial resource
Biogas	On-off within seconds			High costs Requires storage capacity for flexible operation
RES	100%/min	N.A.	N.A.	High opportunity costs due to lost production Specific technical equipment required
Industrial Demand-response	20% /min - 100%/min	N.A.	N.A.	Need for sufficient incentives: high organisational efforts might not be worth the savings
Small-scale Demand-response	100%/min	N.A.	N.A.	Investment in IT infrastructure and data processing Market prices not visible to retail level Data security issues
Pumped Hydro	40% /min - 100%/min	N.A.	N.A.	Long return on investment Very specific siting requirements

Flexibility can be remunerated either implicitly or explicitly. It is remunerated implicitly when the flexibility remuneration is embodied in energy prices. If the product definitions are adequate, flexible units can take advantage of the spread between electricity prices at different times, and to do arbitrage between day-ahead markets, intraday markets and real-time markets. Extreme prices can then be a sufficient incentive for a supply or demand resource to provide flexibility. Flexibility remuneration can also be explicit, through the remuneration of specific flexibility products or technical requirements. California for instance discusses the introduction of new flexible ramping products, while the grid codes in Ireland impose minimum ramping capacity of 1.5% of installed capacity per minute.

Different ways to provide (implicitly or explicitly) flexibility resources can impact the range of flexibility providers, and hence the costs of flexibility (if more efficient resources are excluded) as well as the allocation of costs and revenues between participants. These costs can be aggregated at the system level and socialised between all participants, or more cost-reflective schemes can be conceived. A significant challenge for electricity markets is hence to solve the flexibility measurement problem (i.e. defining and estimating the needs for flexibility), and the flexibility provision problem (i.e. meeting these needs efficiently). It is also important to keep in mind that the flexibility needs and resources vary significantly across Europe. Should dedicated mechanisms target the specificities of each member state? How to ensure their compatibility? Should regional solutions be preferred?

2.2.2 The need for system operation at the distribution level

The traditional organisation of power systems was based on a centrally regulated set of large plants adjusting their production to follow demand. Power would flow from these large generating units through the transmission grid and then through the distribution grid. However, the development of intermittent RES has challenged this vision. The optimal size of units extracting energy from wind and solar is often much lower. In particular, photovoltaic technologies are extremely sizeable, and their efficiency does not change with the size of the installation. Wind turbines do feature economies of scale, but the recent prototype V164 conceived by Vestas as the largest wind turbine on the planet is only 8MW. The development of intermittent RES has therefore resulted in a significant increase of the share of generating units connected at the distribution level. Cossent et al. (2011a) estimated that by the 31st December 2010, 46% of wind capacity and 98% of PV capacity in Spain was connected to the distribution level. Similarly, 86 GW of Germany's installed capacity (48% of total installed capacity) at the end of 2013 was distributed generation (Edelmann, 2013).

This phenomenon is likely to amplify as the costs of PV keeps getting lower and as feed-in tariffs are reduced. Indeed, in this context, "grid parity" is reached when it is cheaper for a consumer to produce and consume its own energy (paying installation costs of distributed generation) than to get the wholesale price and feed-in tariff for production but pay retail prices (including grid costs) for consumption.[7] Schleicher-Tappeser (2012) estimates that the grid parity has been reached in Germany at the beginning of 2012, and that rooftop electricity could be 40% cheaper than electricity delivered by the grid by 2016. Note that in some countries the gap can be further widened by hidden subsidies to prosumers, as grid costs are almost entirely related to capacity (which is not impacted by distributed generation) while grid tariffs are sometimes indexed on net energy consumption (which is lower for consumers owning generation assets).

As the share of distributed generation increases, it becomes a source of technical challenges for system operations. Trebolle (2013) identifies several challenges. First, local congestion does not coincide with system imbalance as local injections can sometimes be several times higher than local extractions. Second, voltage control becomes more challenging as load variations introduce instability in the distribution system. This is also described by Oosterkamp (2014): when the production of power by distributed resources is high and injections higher than load, power flows occur from the distribution level to the distribution level, and voltage rises local-

[7] Other definitions of "grid parity" are sometimes provided.

ly; when the feed-in is low and load is high, voltage may become too low. The resulting instability in the distribution system is illustrated in Figure 9. The variation of DG production already creates today local issues of power quality and these issues are expected to become more frequent as the penetration of distributed generation resources increases. As a result, it is clear that as more perturbations occur at the distribution level, distribution system operators (DSOs) cannot continue to do "business-as-usual".

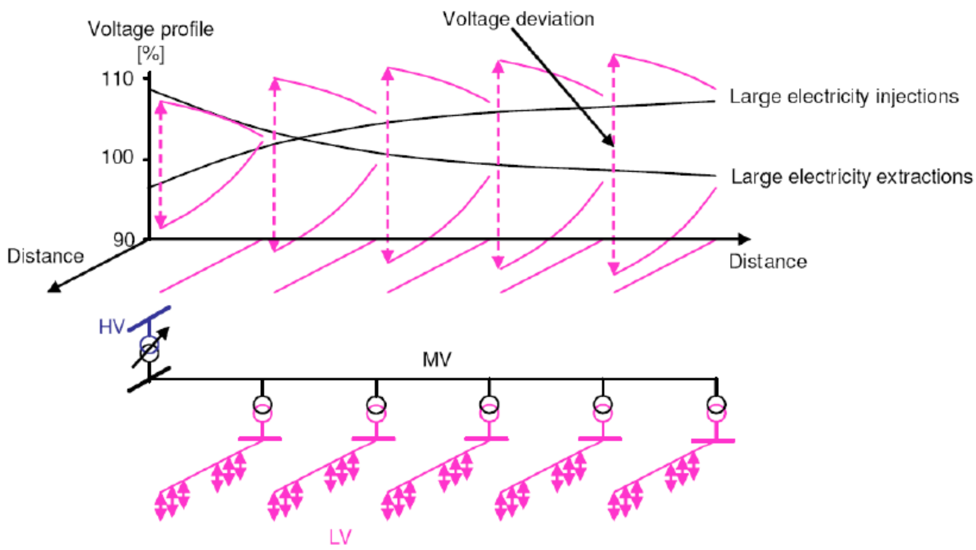

Figure 9 **Voltage variations for different levels of injection and extraction by distributed generation and load. Source: Meeuwsen (2007) as quoted by Oosterkamp (2014)**

However, integration of distributed resources is not only about new issues, it is also about new solutions to ensure the reliability of power systems. Distributed generation can be managed actively to provide upward or downward adjustments to the system when needed, and contribute to voltage control, thus saving operational costs and reducing the need for investment in the grid. However, it is important to ensure that the electricity market design will deliver the right incentives for an efficient active participation of distributed intermittent RES. The role of DSOs vis-à-vis TSOs, and vis-à-vis the market, must be reconsidered (Cossent et al., 2011b; Oosterkamp, 2014; Pérez Arriaga et al., 2013). Rather than finding technical solutions to operate the system safely, the challenge of system operation at the distribution level with intermittent RES is about delivering the right regulatory frame and market design to unlock these technical solutions.

2.3 Four intertwined key challenges

European electricity markets were introduced to coordinate both operations of generation assets in the short-term and investment in generation assets in the long-term. The specific features of intermittent RES (described in section 1.1) create challenges for electricity market design in a context of integration of intermittent RES. These challenges are relevant both for operations and for investments, and are not limited to generation assets. They also pervade to the complementary investment and operation of transmission and distribution assets. The four key challenges that we identified can be summarised as: 1/ Ensuring efficient resources adequacy in the long-term (See section 2.1.1.1 and section 2.1.2.1); 2/ Ensuring that the required flexible resources are in place and have incentives to operate flexibly (See section 2.2.1); 3/ Allowing efficient expansion of transmission and distribution grid; 4/ Unlocking efficient system operation at the distribution level. The causality relations between RES specificities and key challenges for electricity market design are described in Figure 10.

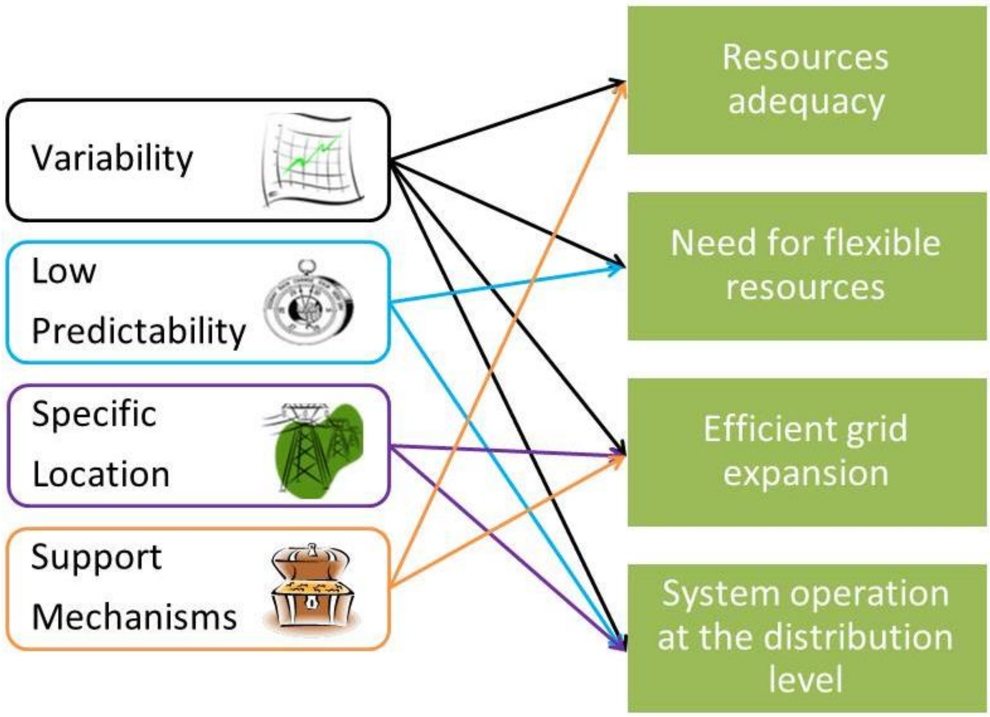

Figure 10 Causality relationship between RES features and key challenges for electricity markets. Own depiction.

Rather than a single factor resulting in a single challenge, the challenges identified are often the product of several factors. The issue of resource adequacy created by variability low load-factor is reinforced by the uncertainty resulting from support schemes. Flexibility is needed to cope with both variability and low-predictability. Grid expansion is needed to accommodate resources located at very specific places, but the development of the grid is made more difficult by the variable output of these resources and uncertain support mechanisms that challenge grid planning. Finally, the variability and the low-predictability of resources located at the distribution level create the need for system operation at the distribution level.

These four challenges are not independent one from another. Flexibility is a prerequisite to generation adequacy (Henriot and Glachant, 2014) while flexibility provision can enhance the cash-flow of supply resources providing generation adequacy. Part of the flexibility required can be delivered at the local level, provided distribution systems operation is revisited. The needs for grid expansion can be reduced (and resources adequacy enhanced) by more efficient ways of operating the systems at distribution level. And of course, grid expansion and interconnectors have a key role to play to ensure generation adequacy.

Finally, when addressing these challenges, one should keep in mind broader issues of acceptability, affordability, and distributional effects. Different solutions can indeed face public opposition, be financially unsustainable, or lead to significant distributional effects, thus preventing their implementation. While this is not considered as an independent challenge in our report, it will be addressed when assessing the solutions proposed in section 3.

3 Design elements to cope with these challenges

3.1 Which energy wholesale market for RES integration?

3.1.1 Which paradigm for RES integration

Section 1.2 explained why renewables cannot be kept out of power markets. In this section, we explore further the concept of RES integration, by introducing (section 3.1.1.1) two paradigms that build on the existing literature: the 'melting-pot' paradigm in which intermittent RES and dispatchable generation are integrated under uniform market arrangements; the 'salad bowl' paradigm in which rules are adapted to the specificities of each set of technologies.[8] We then discuss the pros and cons of each paradigm in section 3.1.1.2.

3.1.1.1 Melting pots and salad-bowls

The first paradigm for RES integration (hereby "melting pot" paradigm) is the simplest one. As the costs of intermittent RES are reduced by their large-scale deployment, these resources could be exposed to the same risks and incentives as more conventional generators. The European association of the electricity generation industry (Eurelectric, 2010) for instance argues that wind generators should be subject to the same scheduling and balancing obligations as conventional power plants. The market would then reach a new equilibrium. Similarly, for Pérez-Arriaga (2012) the share of wind power is reaching such levels that they cannot be considered as neutral passive units. By 2030, intermittent RES will be too big to be allowed to fail: they must operate as other power plants and participate in maintaining power systems stability. Note that full market integration doesn't mean that intermittent RES should not receive additional revenues. There might be additional positive externalities justifying such additional remunerations.[9]

The second paradigm (hereby "salad-bowl" paradigm) is based on the claim that RES integration should address structural discrepancies between intermittent RES and dispatchable generation. Even if the costs of generating electricity using intermittent RES get low enough to compete with dispatchable thermal generators, there will still be fundamental differences between intermittent RES and dispatchable units (See section 1.1). RES integration should then follow a 'salad bowl' approach, taking into account the specificities of each resource and applying different rules to fundamentally different power units.

RES integration is therefore not a well-identified concept, and it can refer to very different approaches. In Section 3.1.1.2, we have a closer look at these paradigms and discuss their pros and cons.

3.1.1.2 Pros and cons of both paradigms

Can a market equilibrium be found with melting-pot integration?

The first general argument against melting-pot integration is a fundamental one: Finon and Roques (2012) argue that investment in RES, even commercially mature, will not be financially viable if current remuneration mechanisms are removed. Low variable costs lead to lower prices, lower annual load factor, and disappearance of scarcity rents resulting from the high correlation between peak demand and wind power contribution. Besides, intermittent RES can suffer from the "cannibalisation effect" described in section 2.1.2.1. RES development would not only impact the development and revenues of RES but also undermine the case for invest-

[8] Section 3.1 builds largely on a recent publication by Henriot and Glachant (2013).

[9] See for instance Borenstein (2011) for a complete discussion of arguments for subsidising RES.

ments in semi-load technologies. By opposition to the assumptions made by Eurelectric (2010), Finon and Roques conclude that the current market arrangements would not lead to a new equilibrium, in which adequate prices could stimulate the needed investment.

However, a solid demonstration of this argument, that contradicts more fundamental economic analyses, is missing. The difficulties currently faced by conventional generators to recover their costs are mostly due to the massive introduction of excess generation capacity in an existing power system, as explained in section 2.1.1.1. What can be observed today is the impact of a shock on a set of previously existing long-lived assets. The interaction between short-run direct effects and the longer-run indirect effects after adaptation of the generation park is for instance described in analytical studies by Sáenz de Miera et al. (2008), and Keppler and Cometto (2013). On the short-run, reduced electricity prices and residual load (defined as load minus generation by intermittent RES) predominantly affect technologies with high variable costs such as gas turbines. On the long-run, the evolution of the residual load impacts mostly technologies with high fixed costs such as nuclear power plants. If this is simply the result of a shock on an existing set of assets, it might be only a transition phase. A simulation realised by the IEA (2014a) also explains how the introduction of a significant share of RES in a certain power system can lead to low load-factors if the generation mix is optimised in the absence of intermittent RES and not adapted afterwards ('Legacy' scenario). If the generation mix is adapted as intermittent RES get deployed ('Transformed' scenario), baseload plants are substituted by mid-merit plants and the load-factor of these assets remain stable. The corresponding evolutions of the generation mix and the load-factor of each unit are illustrated in Figure 11. These results justify the belief of Eurelectric (2010) mentioned in section 3.1.1.1: as the share of intermittent RES increases, a new market-entry equilibrium can be found.

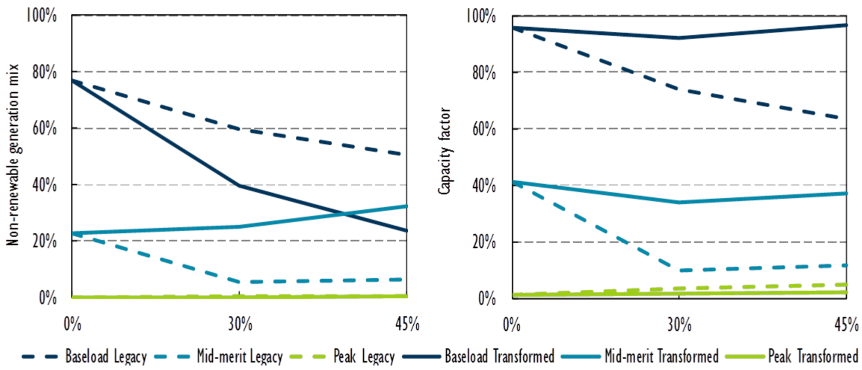

Figure 11 **Evolution of the generation mix and capacity factor of generation assets, for increasing share of intermittent RES. Source: IEA (2014a)**

If a new equilibrium can be found after a transitory phase, there will still be a need for back-up flexible units. These resources (for instance generation capacity or demand side management) will be needed at times when intermittent generation is not available to meet load. Prices would then have to be high enough at times of scarcity to cover the fixed costs of these flexible resources, and a new equilibrium would be found between low-carbon intermittent resources and peak or semi-load technologies. It is true that some of the features of this optimal generation mix, such as high uncertainty attached to the low number of running hours, negative prices, or need for high scarcity prices will lead to risks for investors in all kinds of generation technology. Yet this is not a structural barrier to the long-term coordination of investments by an energy-only market.

A different argument against melting-pot integration for fundamental market failures is provided by the rigorous economic analysis by Chao (2011) and Ambec and Crampes (2012). Both developed analytical modelling and demonstrated that ex-ante uniform retail pricing does not allow decentralising the energy mix. In the absence of dynamic pricing, in which prices are contingent to the availability of the intermittent source, either cross-subsidies or structural integration within a single company would be required to ensure optimal allocation. Indeed, without dynamic retail pricing, consumers cannot distinguish the time when energy is produced at low cost by available intermittent RES. Their consumption, that matches an average tariff, is too high at times when RES are not available. It leads to an overcapacity of conventional plants compared to the optimal generation mix, and hence low profits for these producers. When dynamic retail pricing is implemented, consumption is lower at times when RES are unavailable, and conventional plants only partially substitute the production of intermittent RES. Dynamic retail pricing hence allows market mechanisms to achieve the optimal generation mix, while delivering at the same time sufficient revenues to cover the capital costs for the capacity investment. These results seem to contradict the reasoning of Finon and Roques (2012): the main obstacle to a long-term functioning of an energy market would not be the characteristics of intermittent RES but the lack of dynamic pricing.

Better incentives through melting-pot integration…

A thorough review of the positive effects of 'melting-pot' integration is developed in an analysis of interactions between support schemes and market design realised by Hiroux and Saguan (2010). These benefits include optimal selection of generation sites, improvement of maintenance planning and technology combinations, control of production in extreme cases and higher efficiency of system balancing in general, incentives for innovation, better production forecasts and transparency (See Box 1 for more details). As a result, the authors of this study recommended to increase the exposure of intermittent RES to price-signals by adapting support schemes, and to eliminate distorted market signals. Hiroux and Saguan however acknowledged that it might lead to higher risk and higher transaction costs that should be taken into account.

… but is it worth the risk ?

Salad bowl integration is sometimes justified by a reduction of risks and transaction costs, rather than by fundamental market failures. As pointed out by Klessmann et al. (2008), exposing RES to market signals to which they are not able to react will hinder RES development without bringing any (or little) benefits. As wind power producers have high incentives to generate electricity whenever the wind is blowing, it is pointless to expose them to more accurate price-signals. Higher risks will lead to higher capital costs, and more complex schemes will also favour large players. Batlle et al. (2012) also insisted on the fact that there is little efficiency improvement when linking remuneration of RES to wholesale electricity prices, as non-dispatchable generators have no mean to adjust their output. The scope for efficiency gains by planning maintenance at times of low electricity prices will also be quite limited, as availability rates are very high. In their survey about RES integration in Europe, Eclareon (2012) estimated the technical availability factor of wind turbines to 97.5% while it is close to 100% for PV panels.[10] As a result, melting-pot integration would therefore increase risks for intermittent RES while the prospect for efficiency incentives would remain limited.

This argument makes sense at times when the priority is to develop significantly the share of RES in the generation mix. However, in a system featuring a high share of intermittent RES, these risks are transferred to conventional generators and to consumers, who undergo the price and volume effects. For instance, the schemes of tradable certificate that feature quantity caps can present risks for developers, as overproduction and oversupply of certificates leads to very low prices. But schemes that do not feature any quantity cap can lead to excessive costs for consumers (or taxpayers) if the schemes are too successful. Similarly, feed-in tariffs give producers a fixed revenue that is not impacted by market prices, while feed-in premium are sometimes presented as more risky for developers. But if market prices go low, the resulting surcharge for consumers to pay feed-in tariffs increases, while it remains stable with premiums. In both cases, risk does not disappear; it is transferred between producers and consumers. Risks should hence simply be allocated back to the entities that are most able to manage them.

[10] This impressive figure is due to the fact that there are no moving parts in PV; maintenance mostly consists in cleaning the panels.

Box 1 **Benefits of intermittent RES integration into electricity markets. Source: Hiroux and Saguan (2010)**

Optimal selection of generation sites related to generation pattern
Developers have incentives to pick generation sites that generate more energy at times when it is more valuable for the power system, which is reflected by higher energy prices in wholesale markets. This can improve the variability issue described in section 1.1.1.

Optimal selection of generation sites related to congestion costs and losses
Short or long-term locational signals allow a better trade-off between better generation sites (in terms of output) and extension of the grid, thus mitigating the issue of location constraints described in section 1.1.3.

Improvement of technology combinations and portfolio effects

Developers have incentives (through energy prices and tariffs) to pick technologies that generate more energy at times (and places) when (where) it is more valuable for the system. This can enhance geographical and technological diversification, counterbalancing the cannibalisation effect described in section 1.1.4.

Improvement of maintenance planning

Maintenance is operated at times when wind generation has less value for power systems, and hence when energy prices are low in wholesale markets.

Control of production for extreme cases of imbalance and network constraints

Exposure to market prices can lead to voluntary curtailment when prices become low enough to compensate generation premiums, thus mitigating the variability issue (section 1.1.1).

Improving controllability by innovation

Increased exposure to market signals can also give incentives to RES owners to develop control tools so as to take advantage of controllability, therefore reducing the variability challenge introduced in section 1.1.1.

Improving individual forecasting and system balancing efficiency

Increased exposure to market signals (and in particular exposure to balancing prices) can also give incentives to RES owners to develop forecast tools, therefore reducing the low-predictability challenge introduced in section 1.1.2.

Transparency of the support schemes

Finally, an argument of a different nature is a better identification of support to intermittent RES, that otherwise mixes direct support (e.g. premium to generation) and indirect support (e.g. balancing congestion). This could help clarifying the issue of support schemes discussed in section 1.1.4.

Finally, Batlle et al. explained that exposing RES-E to market prices would create incentives for incumbents owning both conventional and RES generation to abuse their market power. Therefore, they recommend to distinguish non-dispatchable RES from dispatchable RES, and to expose only the latter to price signals. Yet, there are more proper way to deal with market power abuse than introducing an artificial separation between intermittent resources and dispatchable generators. In addition, if a large part of the market resources is made to behave in a non-flexible way, it is likely to increase the market power of the remaining dispatchable generators.

Conclusion

From this section, we can therefore conclude that the only major obstacle to melting-pot integration is the absence of dynamic pricing. While salad-bowl integration can reduce risks for intermittent resources and foster their development, this is not efficient in a system featuring a high share of technologically mature intermittent resources. Last but not least, the alleged fundamental inability of energy markets to remunerate generators as the share of intermittent RES increases is yet to be proved.

3.1.2 Evolution of products exchanged

As suggested in section 1.2, "operation of power systems with a strong presence of intermittent generation has to be profoundly reconsidered". In a liberalised energy market driving operations of power systems, it means that the issue of market design remains highly relevant independently from the paradigm chosen for integration of intermittent RES. Even in cases when intermittent RES are kept isolated from the electricity markets, power systems (and hence power markets) will still be impacted by RES. An extreme case of isolation is for instance the one in which a large share of RES has full priority of dispatch and receives fixed tariffs. RES production is then considered as inelastic negative demand, but the load factor of thermal units as well as the congestion of transmission lines is still driven by their output.

Exchanges in electricity markets are based on a set of temporal and locational definitions, and these definitions are based on a trade-off. On the one hand, broader and simpler definitions enhance liquidity and reduce transaction costs. On the other hand, more accurate definitions allow participants to express better their willingness to pay, as well as their true opportunity cost, for a specific product. European power markets have logically been conceived to deliver market signals adequate to conventional units rather than to the features of intermittent RES. Besides, simplifications have been introduced with the aim to enhance competition: energy products are for instance typically defined on an hourly basis while geographical zones are kept simple and often correspond to national zones. As the share of variable sources of energy in the generation mix increases, leading to faster variations of the residual load and congestion patterns, the impact of these simplifications gets more significant, and these definitions might need to evolve.[11]

3.1.2.1 Time-units

The need for finer temporal signals

As the share of intermittent RES increases, their variability becomes the main driver of variations of the residual load[12] variations. Flexible resources need accurate signals to deliver energy when needed and shorter time-units are necessary.

A finer temporal granularity of prices is therefore essential to provide the appropriate price-signals to investors in flexible resources and cope with the flexibility challenge described in section 2.2.1. Hogan (2010) therefore argued that temporal granularity should match as close as possible real operations. Without market signals accurate enough, flexible technologies would either be too expensive to operate or require additional support.

In addition, shorter time-units also contribute to shifting risks from TSOs to Balancing Responsible Parties, as TSOs must fill the gap between products definitions and the actual needs of the system (Frunt, 2011). Figure 12 illustrates how less differentiated pricing leads to a higher role played by the System Operator and to further

[11] Note that, while this is out of the scope of this study, the need for new definitions could also impact the gas markets, as a result of the significant role played by gas-fired power plants in renewables integration into the network. (Henriot et al., 2012)

[12] Residual load is defined as load minus generation by intermittent RES

socialisation of the costs incurred: the variations within the time-unit must be covered by the TSO, as market participants do not receive any signals for differentiated production within this time-unit.

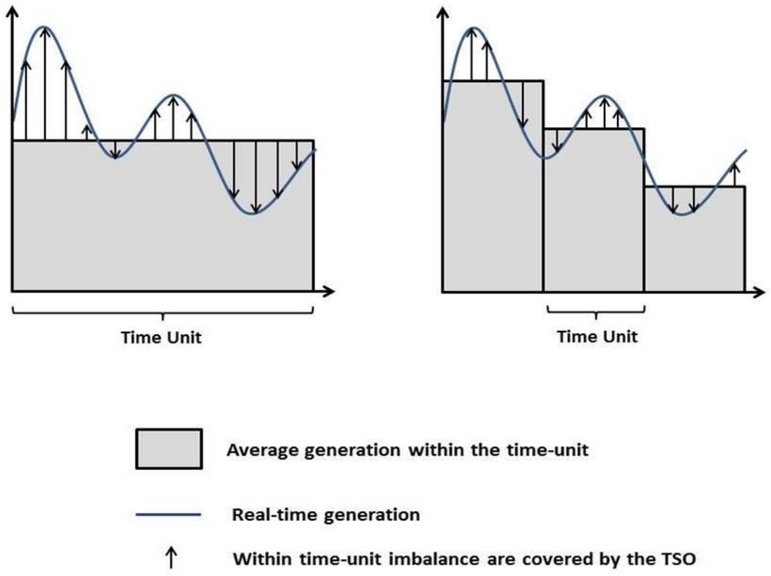

Figure 12 **Illustration of the roles played by the TSO and balancing responsible parties for different time units. Source: own depiction adapted from Frunt (2011)**

Fifteen-minute products have already been introduced in Germany in the intraday market in December 2011, followed by 15-minute day-ahead call options in December 2014. An analysis of intra-day prices reveal that these fifteen-minute prices are needed to reflect the needs of the German power system.

Challenges created by non-convex costs

While reducing time-units can lead to significant benefits and transfer more responsibilities from the TSOs to Balancing Responsible Parties, challenges could arise due to the lack of adequate remuneration for non-convex costs (start-up costs, ramping constraints) in present European energy markets (IEA, 2012). European electricity markets are based on marginal pricing, assuming that it is always more costly to increase production. Yet, it is sometimes costly for inflexible power units to cycle or stop production (See 2.2.1), which is not compatible with marginal pricing and difficult to reflect through hourly prices. While such inefficiencies were estimated by Stoft (2002) to be as low as 0.01% of retail electricity costs in conventional electricity markets, these costs might be underestimated when the number of cycling increases (Troy, 2011) as a result of RES variability.

As shorter time-units are introduced in electricity markets, non-convex costs might become an issue. If the whole start-up costs have to be internalised in a single energy bid, the shorter the time-period, the higher the impact will be on electricity prices: internalising start-up costs in a 5-minute energy bid would for instance result in a price increase that would be 12 times higher than for a one-hour energy bid. Such non-convexities could exacerbate the adequacy challenge described in section 2.1.

"Block orders" have been implemented in European electricity markets to handle non-convexities and give market participants an opportunity to express the complementarities between the different production horizons. A block order is executed under the condition that the average price of electricity across the block-duration is higher (or lower) than a certain threshold. Yet, complex blocks could be more difficult to manage in a power system featuring a high share of intermittent RES, for two reasons. First, computation time and complexity for participants might become an issue in a system featuring a high number of smaller time-periods with many different complex bids. In a system featuring 24 one-hour products, the number of possible consecutive block orders within a day is 300, and computation time then remains limited (Meeus et al., 2009). In a system featuring 288 5-minute products, the number of consecutive blocks within a day is a much more significant set of 41616 combinations. Second, Borggrefe and Neuhoff (2011) also pointed out that block bids can prove quite efficient as long as it is relatively easy to identify block of hours for which demand will be higher. It is quite understandable, as the existence of well-identified peak periods spontaneously reduces the number of consecutive blocks actually traded within a day. However, as the pattern of residual load becomes more complex, block bidding will also prove increasingly challenging: there will be more peak-periods, and these periods will be difficult to foresee.

3.1.2.2 Space-units

Most authors seem to agree on the necessity of more accurate locational signals in a context of a large-scale development of intermittent renewables (Green, 2008; Hogan, 2010; Smeers, 2008).

The first reason is that the best locations for wind farms are often far from load centres and that as a result there will be a need for significant transmission investments (See section 1.1.3). As trade-offs between good generation sites and locations with low connection costs become increasingly relevant, efficient signals should be provided to investors. Green (2008) also claims that the greater need to avoid high-cost locations is a strong argument in favour of locational pricing. The second fundamental argument in favour of nodal pricing is the impossibility to clearly define zones that would reflect physical realities at all times. As congestion patterns driven by a fluctuating RES output will evolve constantly, nodal pricing seems to be the only option able to match reality at all times (Neuhoff et al., 2013).

In the absence of locational energy pricing, locational transmission tariffs or deep connection charges could be used. It is however difficult to reflect fluctuating congestion patterns by using fixed locational charges. We come back to this issue in section 3.2.4.

Note that it is not only an issue of allocating domestic transmission capacity allocation but also of allocating cross-border capacity. Smeers (2008) for instance argued that the simplifications introduced to couple markets in the Central Western Europe area would backfire with the growth of wind power. Borggrefe and Neuhoff also insisted on the necessity to enhance trade between regions: this is indeed a prerequisite to mitigate the variability of intermittent RES by making the most of the geographical spread and the technological spread at the European scale (See section 1.1.1). They identified two potential solutions: integration within a single nodal pricing region, or coordination of nodal pricing in adjacent systems.

3.1.2.3 Price boundaries

Electricity markets typically feature price limits introduced by regulators to protect consumers against overcharging, in a context of low demand-elasticity. As the profile of the load served by dispatchable generators evolves, more differentiated price-signals are needed to remunerate the flexible resources necessary to operate the power system safely. Bertsch et al. (2013) argue that more differentiated price-signals would ensure flexibility remuneration, as being available to react and take advantage of extreme prices constitutes a sufficient incentive to be flexible.

Price caps

As a consequence of an increasing penetration of intermittent renewables, operations by power generation units will become more variable, and some peaking units will be needed to run only a few hours a year. Price-caps should then be high enough to allow these peaking units to recover their fixed costs over these running hours, so as to avoid a "missing-money" problem (See section 2.1.1). Note that in theory, price-caps are put into place to compensate for the lack of demand-response and should be set as equal to the value of lost load (VOLL) for consumers. As the VOLL is not affected by renewables, price-caps should in theory remain identical when the penetration of intermittent RES increases. Yet in practice, the VOLL is difficult to estimate and price caps are very different among power systems with similar consumer preferences: in Spain OMEL has a cap of €180.30/MWh, in Denmark ELSPOT has a cap of €2000/MWh, the German market has a cap of €3000/MWh. A literature survey of estimates for VOLL was conducted by Cramton (2000) who determined that estimates ranged from $2,000/MWh to $20,000/MWh.

According to Eurelectric (2010), low price-caps constitute artificial limits to scarcity-price signals, and undermine the long-term investment prospects in new generation. Yet, a brief analysis of the day-ahead prices in Spain and Germany from January to August 2013 reveals that price caps have not been a binding constraint, neither in Spain nor in Germany (See Table 3).

It is important to take into account the impact of implicit price-caps as a result of unpriced actions by the system operator. This notion has been developed by Joskow (2008), who argued that, in the US, these actions play a much more significant role to suppress prices than do the price caps. System operators can for instance slightly reduce system voltage before implementing rolling curtailment; such costs are dispersed among consumers and not reflected in market prices. System operators can also rely on bilateral out-of-market contracts to secure generators with specific characteristics that are not reflected in product market definitions, thus depressing wholesale and reserve markets (Joskow, 2008). Further examples of such actions also include emergency imports and load shedding if their purchase price is not used as the system marginal cost. Relying on prices to reflect scarcity implies that these administrative prices are substituted by marginal prices of energy at all times. This is a prerequisite to solving the generation adequacy challenge through energy and reserve pricing.

Price floors

Negative prices can appear in electricity markets even without intermittent generation, due to non-convexities of power plant generation costs (see Section 3.1.2.1 for further explanation on non-convexities). Indeed it can be costly for a power plant that is not perfectly flexible to stop and start again, or to cycle down and up. It is therefore rational for a producer to internalise these costs in its bids, sometimes offering energy at prices below marginal costs and even below zero, so as to avoid variations of the output. In other words, the producer can sell at a loss at a given time so as to avoid additional costs in the following hours. The introduction of a large quantity of intermittent generation capacity with variable output (see section 1.1.1) will hence naturally lead to a higher occurrence of negative prices.

There is no theoretical rationale for a limit to price-floors, and the floor for day-ahead prices is very different indeed in electricity markets like Spain (No negative prices), Denmark (-200€/MWh as in the rest of the Nordpool area), or Germany (-3000 €/MWh as in the rest of the CWE area).

Monthly extreme values of day-ahead prices in Spain and Germany for 2013 indicate that the absence of negative prices in the Spanish electricity markets is already probably a binding constraint (See Table 3). In order to reveal the real value of flexibility, such a constraint should be removed. In particular, in a market in which intermittent RES receive a premium X in addition to market price, the floor for prices should be at least lower than -X, so that RES get an incentive to curtail generation at times of extremely low prices.

This issue becomes even more crucial when taking into account cross-border exchanges of electricity. As pointed out by Eurelectric (2010), the lack of common market rules regarding negative prices will lead to distortions when joining offers of energy in zones with different price boundaries.

Table 3 **Minimum and maximum hourly prices in the day-ahead market in Spain and Germany. Source: OMIE monthly market report; Mayer (2013)**

	SPAIN		GERMANY	
Month	**Minimum hourly price**	**Maximum hourly price**	**Minimum hourly price**	**Maximum hourly price**
January 2013	0.00 €/MWh (16 hours)	87.54 €/MWh	-0.10 €/MWh	98.50 €/MWh
February 2013	0.00 €/MWh (32 hours)	90.00 €/MWh	7.30 €/MWh	99.90 €/MWh
March 2013	0.00 €/MWh (165 hours)	90.00 €/MWh	-50.00 €/MWh	120.20 €/MWh
April 2013	0.00 €/MWh (211hours)	90.00 €/MWh	0.00 €/MWh	109.40 €/MWh
May 2013	16.70 €/MWh	72.50 €/MWh	-3.60 €/MWh	73.90 €/MWh
June 2013	0.00 €/MWh (4 hours)	57.25 €/MWh	-100 €/MWh	60.00 €/MWh
July 2013	11.50 €/MWh	68.69 €/MWh	7.00 €/MWh	65.30 €/MWh
August 2013	20.00 €/MWh	62.88 €/MWh	6.00 €/MWh	130.30 €/MWh
September 2013	1.00 €/MWh	72.00 €/MWh	-0.10 €/MWh	77.70 €/MWh
October 2013	3.05 €/MWh	79.99 €/MWh	-49.10 €/MWh	85.80 €/MWh
November 2013	0.00 €/MWh (2 hours)	72.08 €/MWh	1.40 €/MWh	114.30 €/MWh
December 2013	0.00 €/MWh (37 hours)	112.00 €/MWh	-62.00 €/MWh	116.50 €/MWh

3.1.2.4 Ensuring inter-temporal consistency between the different markets

The rising importance of balancing markets

The key-role played by the day-ahead market in electricity markets today does not match the needs of intermittent RES. The output of these resources is difficult to forecast (Section 1.1.2) and these forecasts of wind improve significantly from day-ahead to real-time, as illustrated in Figure 2. Intraday markets that give stakeholders an opportunity to trade after the day-ahead gate-closure, and real-time balancing markets, should therefore play an increasingly significant role as the share of intermittent RES increases.

Cramton and Ockenfels (2011) accordingly argue that well-designed power reserve markets interlinked with each other through arbitrage can ensure recovery of fixed costs for back-up generation and, more generally speaking, long-term efficient exit and entry decisions. Prices in the reserve markets will rise compared to prices in the day-ahead market in case of higher scarcity of flexible power plants compared to inflexible power plants, therefore delivering the right investment signals and solving the need for flexible resources described in section 2.2.1 (Barth et al., 2008). It would however require adaptation of the market, such as avoiding block auctions for provision of reserves over a month or a week(which could make arbitrage between day-ahead and reserves provision more difficult) (Boot et al., 2014).

One must yet keep in mind that all the products aiming to deliver energy at a certain production time are substitutes. The more products defined, the lower the liquidity will get for each of these products. Liquidity remains for instance quite low in the intraday markets implemented in Europe, which could be explained by their inadequacy to the real needs of stakeholders, and the complexity for these players to realise arbitrage (Weber, 2010). This is why the IEA (2012) warned that the definition of too many flexibility products could create issues of market liquidity and market power, and claimed that the number of products defined should remain limited.

Moreover, if reserve markets play a significant role, RES should be able to participate into the full sequence of markets for the different products, as suggested by the IEA (2012). Note that it does not require the mandatory participation of RES into balancing markets, and that it could even prove costly to constrain intermittent RES to manage their production actively (Henriot, 2014). The only requirement would be to expose RES to balancing costs and to give them the possibility of delivering balancing services. Here again, it would be crucial to make reserve provision flexible by avoiding the 'block auctions' mentioned above.

Ensuring consistency between day-ahead and balancing services

Smeers as well as Borggrefe and Neuhoff (2011) criticize the multiple arrangements governing the organisation of day-ahead, intraday and balancing markets. For Smeers (2008), a single trading platform should be put into place, with continuous active trading from day-ahead to real-time. Components currently missing include intra-day markets for reserve capacities, and the integration of congestion management with the intra-day markets and ancillary services markets. When transmission capacity is priced in the day-ahead market but is free in the intraday market, distortions are created that shatter the inter-temporal consistency between the different trading spaces. For consistency purpose, the locational granularity should then be the same for the forward markets (e.g. day-ahead) and the balancing markets. A fully functional market for locational reserves would then be needed (Baldick et al., 2005).

Other distortions can hinder the financial links between the forward markets (i.e. day-ahead and intraday markets) and the balancing arrangements. Vandezande et al. (2010) described how the existence of asymmetric penalties in some balancing mechanisms would penalise wind producers and generate incentives to under-nominate injections in the forward electricity markets, leading to higher total system costs. Similarly, De Vos et al. (2011) pointed out that putting a cap on imbalance tariffs would "[violate] the link between the reserve market and the imbalance tariff" and thus endanger the well-functioning of balancing markets. As a consequence, the definitions and boundaries mentioned in the previous sections should be applied similarly in the full sequence of markets.

Green (2008) also advocates integration of energy and ancillary services, as it is often the case in the United States. Such a model is based on the use by the system operators of a dispatch algorithm taking into consideration the technical constraints of producers and the network to optimise simultaneously provision of both energy and reserves products. It is then possible to take into account efficiently the different technical constraints and manage the different substitutes in a single optimisation program, without increasing the complexity for participants. Similarly Borggrefe and Neuhoff (2011) favour pool type trading arrangements and joint provision of energy and balancing services. This would solve the lack of consistency resulting from a separation between balancing services that are typically acquired by the TSOs, and energy products in day-ahead and intraday markets, that are exchanged either on power exchange or bilaterally.

3.1.2.5 Conclusion

Redefining products definitions in wholesale electricity markets and revisiting their interaction with reserve markets can contribute to solving some of the key challenges identified in section 2.

Shorter time-units will be needed to handle the variability of intermittent RES, and solve the need for flexible resources that has been identified as one of the key challenges described in section 2.3. However, the existence of non-convex costs (that will gain in significance as a consequence of RES variability) could worsen the resource adequacy issue for flexible resources, if not addressed properly.

More accurate space-units will be needed to tackle efficiently the grid expansion challenge. As a result of variability, these space-units will have to be small enough to conserve a meaning for different states of the system.

Yet, this might lead to serious redistribution effects that will have to be addressed to ensure acceptability of the new definitions.

More differentiated price-signals are required to solve the resource adequacy challenge, and to ensure the development of flexible resources. It is not only about higher price-caps and low negative prices; it is also about explicitly pricing the actions taken by the system operator to ensure the security of the system.

Finally, the role of the day-ahead market will lose its significance as exchanges will take place closer to real-time due to the low-predictability of RES. The consistency between the different markets and products exchanged should be ensured as they will drive the remuneration of resources in general and flexible resources in particular. It implies that the previous recommendations also address products definitions in the balancing markets.

3.2 Coordination tools

3.2.1 The need for coordination tools

We have described in section 1.1.4 how the development of intermittent RES is the result of strong support policies. These policies impact the revenues of conventional generators and intermittent RES ("cannibalisation effect") and create a challenge of resources adequacy. At the same time, these policies also complicate the task of the TSOs (and DSOs) when planning grid expansion (see section 2.1.2).

The issue of coordination of generation and transmission investments is not new, and existed before RES. Green (2006) argued that without long-term contracts, electricity markets were likely to fate boom and bust cycles, as a result of investor's inability to keep track of others' investment decisions. There is therefore a need for coordination tools between generation assets, to avoid oversupply or scarcity. In Europe, electricity markets were supposed to deliver the signals required, but concerns on their ability to ensure generation adequacy have recently been growing, while utilities overinvested in the past decade (See Figure 4). This pre-existing weakness of European electricity markets is of course worsened by the uncertain development of intermittent RES. This has led to the emergence of national capacity remuneration mechanisms in several member states, as a patch to ensure coordination of generation investments. We investigate this solution in section 3.2.2.

A further difficulty comes from the fact that transmission investments are now made in a European energy market. There is therefore not only a need for coordination of investments within each TSO operation area but also coordination of investments and operation between the different control areas. This is challenging as transmission investment frameworks typically reflect the organisational and political boundaries (Joskow, 2006). However it is a prerequisite to unlock a regional approach to resources adequacy and mitigate the variability of RES by making the most of the geographical and technological spread of intermittent RES. The emergence of tools focusing on cost-benefit analysis and allocation are part of a toolkit that will be required to optimise operation and investment at the European level. We discuss this solution further in section 3.2.3.

Peréz-Arriaga and Olmos (2006) also identified the lack of economic signals to coordinate interactions between transmission and generation expansion as a major unsolved problem. Transmission investment should aim at minimising the total costs of transmission and the production costs of power, but it is not easy for planners to anticipate the moves of generation investments, especially as generation investors respond strategically to the decisions taken by the TSO (Stoft, 2006). Tools ensuring coordination of generation and transmission investments include advanced planning tools as well as locational signals. We explore these solutions in section 3.2.4.

3.2.2 Coordination between generation assets

3.2.2.1 From commercial to administered coordination mechanisms

Without a long-term coordination mechanism, it is difficult for investors in generation assets to anticipate the moves of their competitors, leading to a cycle of oversupply followed by scarcity (Green, 2006). In the textbook reform of electricity markets, the long-term coordination role traditionally played by monopolistic vertical integration was to be substituted by the development of long-term contracts (and the complementary options, contracts for differences, swaps…) traded on financial forward markets or over-the counter (de Hautecloque and Glachant, 2011). Long-term contracts reduce price-risk and volume-risk for investors. They can also act as a long-term coordination device as the demand for these contracts will depend on the estimates by retailers and large consumers of their expected demand (Green, 2006).

However, long-term contracts have failed, for several reasons, to provide the coordination signals required to ensure efficient resource adequacy. First of all, generators have encountered difficulties to find counterparties, due to the reluctance of retailers who have a legal obligation to allow their customers to switch providers within short-notice. Indeed, in case of lower prices, retailers having secured higher prices through long-term contracts would have either to sell energy at a loss or to see their customers switching to suppliers (Green, 2006). Long-term contracts therefore increase price-risk and volume-risk for retailers in a competitive environment. Exceptional counterparties who need long-term contracts with prices secured over a long time-span can only be found in electric-intensive industries (Finon, 2011). A second reason why long-term contracts did not develop as planned is the difficulty to develop long-term derivatives in the electricity sector that features non-storability. Finon and Perez (2007) explains that while the contracts observed usually cover at most two years and are therefore too short to accompany the development of new capacities, longer-term derivatives cannot be established by banks or hedge funds who commonly create liquidity in other commodity markets. Finally, the European Commission has been reluctant to allow long-term contracts with significant durations and volumes, in order not to hamper the opening of markets to competition (de Hautecloque and Glachant, 2011).

Today, the contract incompleteness in the electricity sector has become even more crucial. First of all, a lot of the low-carbon technologies feature higher capital expenditures. This is for instance the case of intermittent RES, nuclear power plants, or thermal plants equipped with Carbon Capture and Storage. It is crucial for these plants to secure the significant upfront investment cost by long-term contracts.[13] In addition, power plants now need to secure revenues based on policies that do not come with credible future markets (such as the carbon prices).

As a result, an increasing number of discussions on the development of alternative long-term coordination mechanisms are taking place in Europe. These administered rather than commercial coordination mechanisms will hereby be designed as generation adequacy mechanisms, reflecting the current preoccupation of governments implementing these solutions (See Figure 13). In the next sections, we do not discuss the details and the rationale for each mechanism, but rather the two main implications of these national patches to electricity markets.[14]

[13] In the case of intermittent RES, the volume-risk is solved by priority of dispatch while the price-risk can be partly or entirely reduced by support schemes that act as some form of long-term contracts.

[14] These two sessions are based on the work by Henriot and Glachant (2014).

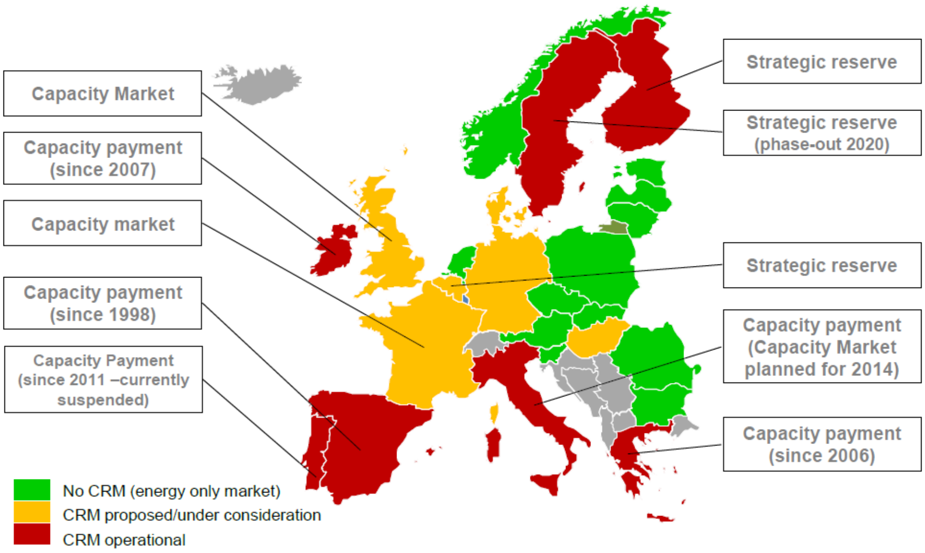

Figure 13 **Status of capacity remuneration mechanisms in Europe in 2013. Source: ACER (2013).**

3.2.2.2 Generation adequacy policies and the need for flexible resources

These new long-term coordination tools are based on the remuneration of a certain amount of capacity, so as to make sure that this minimum amount of capacity will be there when needed. Yet, as mentioned in section 2.3, the challenges of resources adequacy and the need for flexible resources cannot be fully decoupled. In a system featuring a high share of intermittent RES, ensuring resource adequacy is not only about achieving a certain capacity margin, it is also about making sure that the installed resources are flexible enough to cope with the variations of RES illustrated in Figure 8. It implies that efficient long-term coordination mechanisms ensuring efficient resource adequacy will have pervasive impacts on the short-term mechanisms coordinating power systems operation.

Indeed, remuneration of capacity for availability when needed conversely implies higher opportunity costs of unavailability. In particular, resources will have to be available at times when RES output drops quickly to low levels. For an inflexible thermal unit featuring slow ramping rates and long start-up times, it implies that such units would have to start generating earlier, when intermittent RES are available and electricity prices are low (or even negative). On the opposite, more flexible units (able to start-up and ramp-up quickly) could avoid generating at a loss. Even the simplest generation adequacy policy would hence incentivise a more flexible operation of resources by raising the opportunity costs of unavailability. Of course, one might argue that some clauses could be introduced into the design of the generation adequacy policies to exempt inflexible plants from penalty when flexibility would be needed to react. Yet, such clauses would considerably weaken the level of generation adequacy ensured in a system featuring a high share of intermittent RES.

Generation adequacy will therefore become an additional component of the remuneration for flexibility, which is made of a combination of implicit and explicit revenues (See section 2.2.1.2). In a long-run entry equilibrium, this combination of revenues must be just sufficient to cover the costs of providing this flexibility. An additional source of revenues (through generation adequacy policies) will mechanically lead *ceteris paribus* to compensation through lower revenues in another component of flexibility remuneration (e.g. the energy wholesale market, the market for ancillary services), as illustrated in Figure 14.

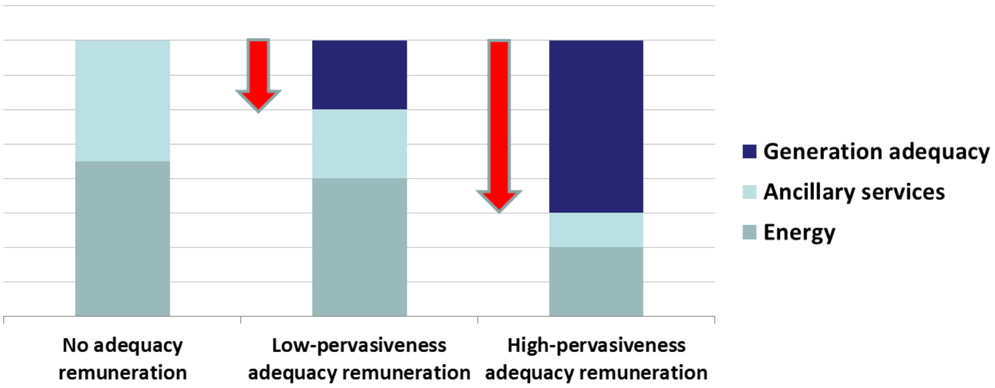

Figure 14 Distribution of flexibility revenues in the long-term across a set of explicit and implicit remunerations. Own depiction.

This evolution of the revenues distribution across different markets is not an issue as long as all the resources that provide flexibility can take part into the generation adequacy policies. Yet, in practice, the range of resources that can take part into generation adequacy policies is often restricted in terms of technologies (e.g. intermittent RES, demand-side resources) and locations (i.e. cross-border resources). Such discrimination can be explicit: cross-border resources are for instance not remunerated in many capacity remuneration mechanisms. It can also be implicit: availability requirements (number of calls, availability across a long uninterrupted period) can be incompatible with the capacity of demand-side resources or intermittent RES; limitations on the lowest possible bid can also exclude smaller generation or demand-side units. As the remuneration of flexibility is partially transferred from the energy and ancillary services markets to a discriminating generation adequacy policy, the range of resources able to offer flexibility will inevitably be reduced. This impact will be all the more significant if flexibility remuneration through the capacity mechanism is larger, and if the mechanism is more exclusive. It implies that the way the key-challenge of the need for flexibility is addressed will depends on the tools used to cope with the resources adequacy challenge. This could be especially costly as there is uncertainty regarding the best set of resources[15] required to meet the need for flexibility.

3.2.2.3 Coordination of generation assets will be national

There is already a patchwork of capacity remuneration mechanisms in Europe, as illustrated in Figure 13. The diversity of solutions implemented is the logical consequence of the diverse needs, resources and objectives of Member States, as reflected in Table 4. It is therefore unlikely that a common scheme could fit all Member states.

Yet, the benefits of a European approach towards security of supply are significant when compared to a national self-sufficient approach. First, the current reserve margins and future needs vary across Member States. Second, scarcity events across neighbouring countries are not fully correlated, which means that the reserve capacities will most of the time not be simultaneously needed by the different national power systems. Sharing these reserves and taking into account a European reserve margin would therefore be a cheaper approach to generation adequacy than defining reserve margins at the national level, even taking into account limited interconnection capacities (Henriot and Glachant, 2014). The additional cost of power systems explicitly providing for their own security of supply at a member state level was estimated to be 3.0 to 7.5 billion euros per year from 2015 to 2030, which would reduce the benefits of an integrated energy market by more than 20% (Booz & Company et al., 2013).

[15] For instance among all the technologies listed by ECOFYS (2014)

Table 4 Priorities and needs of different Member States. Source: Meulman and Méray (2012); Notenboom et al. (2012)

	Roadmap Priorities	Challenges identified	Mechanism
France	1/Affordability 2/Security of supply	- Increasing peak demand - Increasing share of RES	Capacity obligation on suppliers
Germany	1/Industrial opportunities 2/Security of supply	- "Missing money" due to RES - Closure of nuclear plants - Congestion in the transmission network	"Transitory winter strategic reserve" in the South Ongoing discussions
Netherlands	1/Affordability 2/Industrial opportunities	- No perceived need	"Safety net" never used
UK	1/GHG mitigation 2/Affordability	- Closure of existing capacity - More intermittent & inflexible generation	Centralised auction

However, coordination of national capacity mechanisms at the European level will only be possible if a minimum framework is implemented. This framework has been more extensively described by Henriot and Glachant (2014) and consists of three tools. The first tool required us a methodology sophisticated enough to take into account partially correlated evolutions of load and RES production across different Member States, and a common set of inputs and scenarios shared by the different stakeholders. A recent report by the Council of the European Energy Regulators for instance highlighted the need for harmonisation of methodologies and scenarios used to assess generation adequacy at the Member State level (CEER, 2014). The second tool required is a multilateral regulatory framework aimed at allocating responsibility (and the corresponding remuneration) for the delivery of energy when needed. This delivery indeed does not only depend on the availability of the resource committed in the generation adequacy policy, but also on the available capacity of the interconnector and the direction of the flow through this interconnector, which is the result of concomitant conditions in different Member States. A third tool is a method to allocate rights (financial or physical) to consume energy at times of extreme scarcity, while taking into account some solidarity principles. Unless such a framework can be established, generation adequacy policies will remain national patches, with joint consequences on the provision of flexibility.

3.2.3 Coordination between network investment and operation at the regional scale

A well-functioning and efficient transmission network is a pre-requisite to a competitive internal energy market. However, transmission system operators have been introduced as entities responsible for managing and expanding the transmission grid within their control zone (that often matches national boundaries). Incentives are conceived by national regulatory authorities to ensure efficiency within these political boundaries that do not reflect the physical reality of the grid (Neuhoff et al., 2013). There are therefore significant asymmetries between the frameworks for intra-TSO transmission investment planning and operation and inter-TSO transmission investment planning and operation (Joskow, 2006). This is a source of inefficiency as it does not allow managing properly the externalities created by the decisions of each TSO on neighbouring power systems. For Zachmann (2013) European welfare maximisation can only be achieved if three coordination tools are implemented at the European level: a tool for coordination of operations, a planning tool to ensure the coordination of investments, and a tool to allocate costs and benefits of network investments at the European scale.

3.2.3.1 Coordination of power system operations

Operational decisions are mostly taken within national operation centres, with a limited vision of the network state in neighbouring countries. Joskow (2006) argues that these effects gain in significance when the decisions of market players are based on fictional physical characterisation of the interconnected network. Glachant and Pignon (2005) for instance show that the congestion signals sent by TSOs can be in practice a variable complex and non-transparent constraint, that can be manipulated to push congestion out to the borders between TSOs, which reduces internal congestion but is inefficient. Two measures are identified by Joskow: horizontal consolidation of TSOs to internalise externalities, and locational prices to increase transparency and reduce the role played by TSOs. Glachant and Pignon (2005) focuses on the first kind of measures and develop a set of solutions from information exchange, improved transparency of TSOs decisions and harmonisation of procedures, to mergers between TSOs. For Zachmann (2013), a European system-management layer would be needed to first complement, and then substitute, the decisions taken by national operation centres. Zachmann also argues that electricity prices should differ between all network points (across and within countries) when necessary so that more decisions can be taken by generators based on locational signals (See section 3.1.2.2). One should not underestimate the challenge of merging TSOs across a range of national states with different needs and preferences, or the challenge of redistribution effects created by locational prices. However, some voluntary cooperation initiatives to coordinate power systems operations can already be observed in Europe, such as Coreso (COoRdination of Electricity System Operators) in the central Western Europe, or TSC ("TSO Security Cooperation") in central Europe. A description of the role played by Coreso is detailed in Box 2.

Box 2 Description of Coreso activities to coordinate system operation in the CWE area. Source: Own summary based on Coreso website.

Two-day ahead

Coreso is responsible for merging the data (Day 2 Ahead Congestion Forecast) necessary to calculate the cross-border capacities in the market coupling process. Coreso also organises the management of remedial actions (e.g. coordinating phase-shifting transformers) in the CWE area (that covers Belgium, France, Germany, Luxembourg and the Netherlands).
Coreso also merges the best two-day forecasts available from RTE, Terna, Swissgrid , Eles and APG to optimise the import capacity for the Northern Italian border.

Day-Ahead

Coreso merges the Day Ahead Congestion Forecast files provided by each TSO, and realises security analysis by simulating the tripping of lines or generators. It analyses the constraints and identify potential remedial actions. However, any final decision to implement such actions remains the responsibility of the TSOs.

Intraday and close to real-time

Coreso compare the incoming data with previous forecasts, perform security analyses, and advise the TSOs' dispatchers about new constraints. Coreso also calculates cross-border capacity.

Support in the event of major disruption

Coreso has developed tools to analyse major disruption affecting several countries, to help TSOs understanding what is happening in Europe in real-time.

Collaboration with the Great-Britain synchronous area

Coreso also performs analyses to check the transfer limit values at IFA interconnectors between France and the UK, and proposes coordinated solutions between National Grid and mainland TSOs to solve congestion on both sides of the Channel.

3.2.3.2 Coordination of network investments

Investments in the transmission network have strong externalities, and they can be complementary or substitutes. They can result in a wide range of benefits that include among others production costs savings, improved security of supply, local or global environmental benefits (Meeus et al., 2013). The costs and benefits are moreover distributed between the different Member States, and the developers of the project might not be (the main) beneficiaries. It is therefore important to develop a planning process allowing a coordination of investments at the European scale, taking into account all the potential costs and benefits of a certain project. But to ensure the development of the projects identified, it is also necessary to allocate the costs to the stakeholders who benefit the more of these projects.

The EU infrastructure package has been developed with the intention of delivering more cross-border electricity transmission. It features tools for planning, such as the Ten-Year Network Development Plan, and tools for cross-border costs allocation. However, Zachmann (2013) argues that the infrastructure package is only "an extension of the current system of national-welfare centred regulations, a system which does not target the optimisation of the EU electricity network, and as such is inconsistent with a truly single market". Zachmann indeed argues that due to its non-binding nature, the TYNDP cannot ensure the consistency of national network plans. The CEER report on assessment of electricity generation adequacy in European countries has for instance highlighted the inconsistencies between the scenarios developed by the ENTSO-E and the scenarios employed by some Member States when assessing security of supply (CEER, 2014). Zachmann concludes that a more stringent planning would be needed, with a developed governance structure that would include all electricity sector stakeholders (TSOs, generators, large consumers, distribution system operators). At the same time, issues related to cost-allocation could be mitigated by exposing the new generators and consumers to full grid costs reinforcements: if intermittent RES are the main beneficiaries of the network expansion, these costs should not be passed onto society. The remaining share could then be allocated through a European tariff.

3.2.4 Coordination between network and generation investment

Section 2.1.2.2 explained how features of intermittent RES such as their variability, their specific location, and the fact that their development is driven by support schemes make more challenging the unsolved issue of coordination between generation and transmission investment. If the targets for RES penetration are to be achieved, significant investment will be needed in the transmission network (ENTSO-E, 2014). Due to the long development and construction time of transmission lines, the TSOs would have to anticipate the development of the generation mix (Rious et al., 2011). Yet, this will lead to high risks of stranded assets for the TSOs if generation assets do not receive strong locational signals. Stoft (2006) argues that planners would not undertake a project that would lead to the embarrassment of building a line to nowhere.

Lapuerta et al. (2007) realized an overview of the connection policies that have been implemented worldwide. We follow here their classification of the possible measures into three categories: market facilitation, payments made by generator, changing the response of TSOs to connection request and investment in the network.

3.2.4.1 Market Facilitators

A first set of tools that can be used to coordinate investment in transmission and generation assets include measures facilitating market transactions and hence the decisions by generators. Lapuerta et al. (2007) for instance recommended the implementation of tradable connection rights, that a generator could sell with its site to a third party, to avoid the wait for reinforcements to the transmission system. This would give incentives to use generation sites that are already well connected to the network, lowering the needs for network expansion. A complementary measure would be to improve transparency by publishing information on connection capacity available at each substation. Lapuerta et al. also mention more drastic policies such as auctioning sites or connection capacity, but these might lead to strategic behaviors as indicated by Stoft (2006). Use-it-or-lose-it policies and time limits to connection agreement could help preventing the hoarding of connection rights, but they might be difficult to enforce efficiently (Lapuerta et al., 2007), especially when some back-up units will be needed only exceptionally for extreme events created by the variability of intermittent RES.

3.2.4.2 Generator payments

A wide range of connection charges can be applied, each having consequences for the development of the generation sector. Under shallow connection charges, the generator will only pay the grid connection costs, while the complementary network reinforcement costs are covered by network charges. Generators then receive little incentives to invest in locations minimising the needs for investment in the network. Under deep connection charges, both grid connection and network reinforcement costs are paid for by the generator. Deep connection rules therefore provide superior locational incentives (Joskow, 2006).

However deep connection charges are seldom applied, for different reasons. First, it creates significant upfront costs that can constitute an entry barrier to investment in generation capacity. Second, the lumpiness of transmission investments makes it difficult to allocate the costs of network expansion to a given market participant. The electricity network has public good properties and the first-mover in the market might pay for capacities that will benefit other participants. In addition, calculation of deep connection charges will also be more difficult to put into place when a large share of intermittent RES will create significant fluctuations of the power flows and congestion patterns (Henriot et al., 2013).

Another option identified by Lapuerta et al. is to put into place G charges (i.e. transmission tariffs paid by generators) providing locational signals to generators. Such scheme is for instance in place in the UK, where the G-charge ranges between 25.59 €/kW in West Scotland and -7.20 €/kW in Central London with a weighted Average 'transmission network use of system' (TNUoS) tariff of 4.56 €/kW (Ruester et al., 2012b). However, implementing such a charge could lead to significant redistribution effects and issues of harmonisation between the different Member States. In addition, Neuhoff et al. (2013) showed that congestion patterns are likely to fluctuate significantly with a high share of intermittent RES. It is therefore unlikely that fixed connection charges could deliver locational signals valid at all times. A mix of long-term signals and more dynamic locational signals could be needed for cost-reflection, as in the proposal by Peréz-Arriaga and Olmos (2006).

Finally, a last option to ensure the commitment of generators would be to implement up-front payments or cancellation payments for generators asking to be connected to the network (Lapuerta et al., 2007). These are attractive options to mitigate the uncertainty created by the development of generators for the TSO. Peréz-Arriaga and Olmos (2006) explain how Spain had in 2006 standing requests for new connection of 50 GW of wind generators and 50 GW of CCGT power plants, compared to a 2005 peak-load of 43 GW. Most of these requests were not to materialise eventually, and were only made to ensure that the sites would have met all the administrative requirements if needed. Such behaviour makes it very difficult for the TSO to anticipate the adequate network investment. Peréz-Arriaga and Olmos therefore argue that it would be useful to identify the serious requests from the speculative ones by requiring a financial guarantee from the potential investors. This guarantee would only be returned to plants actually built within a certain limit.

3.2.4.3 TSOs response to connection requests and investment needs

A last category of solutions that could be implemented to coordinate generation and transmission investments include reforms in the TSO responses to connection requests and investment needs.

A first solution recommended by Lapuerta et al. is to introduce some discretion in the decision made by the TSOs to connect generators. TSOs should be allowed to refuse connection requests from new generation in certain parts of the network, or requests involving some threshold level of reinforcement costs. Generators should then be able to overturn this decision by paying for the reinforcement costs.

An alternative framework is to give TSOs the possibility of anticipating the development of the network. Rious et al. (2011) show that anticipating the connection of a generator is a source of benefits when the probability that the generator will connect is high (and hence when there are little risks of useless expansion of the network), as well as when it requires significantly more time to build transmission lines than to build generation units. An important issue when it comes to anticipating investments is to find an adequate regulatory frame balancing the risks for the TSOS of not recovering its costs, and the risks for the consumers to pay for assets that were not needed.

3.2.5 Coordination between transmission network operators and distribution network operators

The generation resources have traditionally been large power plants connected to the transmission network. System operation was therefore realized by the TSO who mostly had to monitor the behavior of these large power units, large consumers and the connection points at the border with distribution grid. The network management of DSOs was limited to acting on the network rather than by actively acting on load and generators. The development of distributed resources described in section 2.2.2 will give TSOS and DSOs many more options to actively manage the system at the distribution level. However, this creates coordination issues. On the one hand, actions taken by TSOs at the distribution level (such as the provision of ancillary services) will impact the flows in distribution networks and could lead to constraints in the transmission grid. On the other hand, there are more complex phenomena occurring at the distribution level and hence out of the TSO observability area.

There will also be to clearly define the relevant products that will be provided to TSO and DSOs by distributed resources, as TSOs and DSOS might share interest for some of these products to manage short-term problems in the grid, maintain quality of service, or reduce losses and investment needs (Pérez Arriaga et al., 2013). An example of such services is illustrated in Table 5. It could lead to conflicts if TSOs and DSOs for instance rely on the same resources to respectively keep the system balanced and solve local congestion. Pérez Arriaga et al. (2013) argue that products should be differentiated by region (location-specific or system-wide) and time of delivery (the closer to real-time, the more these products should be procured and used by the entity responsible for short-term supply security).

It is hence crucial for system security to coordinate the TSO with the DSOs and clearly define their respective jurisdictions and hierarchy of functions. Pérez Arriaga et al. (2013) argue that any action on the distribution network should for instance be agreed with the respective DSO, and that TSOs should not act directly on resources connected at the distribution level. In return, DSOs should submit to the TSO (who are responsible for system balancing) clear information on the resources committed to deliver services to the DSO. Real-time communication between TSO and DSOs will also be required: Trebolle (2013) for instance mentions the need for communication of monitoring information from the DSOs to the TSO, and for communication of topology information and day-ahead forecasts and dispatch plans from the TSOs to the DSOs.

Table 5 Expectations of DSOs and TSOs for services provided by distributed resources Source: Adapted from Belhomme and Bouffard (2009)

	DSO	TSO	Short description
Power flow control/Network congestion solution	X	X	Distributed resources can be used to solve congestion on high-voltage, medium-voltage or low-voltage networks through the modification of loads and hence of power flows.
Network restoration/Black start	X	X	Distributed resources can contribute to network restoration after a partial or complete loss of supply on parts of the distribution or transmission network.
Frequency control/Power reserve	X	X	Distributed resources could deliver tertiary reserves, keeping frequency at appropriate levels after unplanned demand increases or production losses. DSOS could have a role to play when a significant share of resources are connected at the distribution level.
Voltage control and Reactive power compensation	X		Distributed generations can contribute to some sort of voltage control to maintain the voltage on distribution networks within certain limits.
Islanded operation/micro-grids	X	X	Under special circumstances, islanded operation of parts of the transmission network or the distribution network may allow supply consumers until restoration of the system.
Reduction of system losses	X	X	Power injection from DG can modify flows and potentially reduce losses on both the transmission and the distribution network.
Optimised development and usage of the network	X		DSOs could use distributed resources to avoid or postpone grid expansion.

3.3 The potential of distributed resources

3.3.1 Distributed resources can contribute to solving the key challenges…

As mentioned in section 2.2.2, a significant share of intermittent RES is integrated at the distribution level, which can be a source for challenges for system operations. However, distributed intermittent RES and demand-side management by small-scale consumers can also contribute to solving some of the key challenges we identified. These distributed resources can indeed provide a set of services with economic value to local electricity markets. These services include provision of voltage support and fault-ride through capacity, provision of ancillary services such as tertiary reserves, improvement of voltage quality and reduced losses, deferring upgrades of the network, and improving power system resiliency (EPRI, 2014). Using a generic distribution network model, De Joode et al. (2009) estimate that penetration of distributed generation is favourable for the DSO for low penetration levels, but becomes unfavourable for higher penetration rates, especially if distributed generation is more concentrated. The main driver for both the positive effects at low penetration rate and the negative effects at high penetration rate is the evolution of losses. This negative impact can only be mitigated by deferring investment, which can have a substantial positive impact.

He et al. (2013) show that demand-side resources can deliver a wide range of flexibility services that differ in terms of reaction time, duration and firmness, provided the adequate contracts are implemented (see Table 6). ECOFYS (2014) more concretely identified a diversity of distributed resources as potential flexibility providers. Active power control of distributed intermittent RES could provide negative reserve control, reduce peaks by a small level of curtailment so as to decrease the need for additional grid capacity, or solve balancing issues created by a high share of intermittent RES. Demand-management in services and households can include among others air conditioning, heating, rescheduling of washing processes, and automatic adjustments in the demand of refrigerators and cold storage, and it allows to optimise operations and improve power systems security. Electric vehicles could also play a role in the future to provide balancing and reserve power.

Table 6 Technical requirements of different services provided by distributed resources. Source: He et al. (2013)

Service type	Reaction time	Duration	Firmness
Structural congestion management	Slow	Long	Low
Portfolio optimisation	Slow	Long or Short	Low
Occasional congestion management	Fast	Short	High
Balancing services	Fast	Short	High
Ancillary services	Very fast	Short	Very High

Of course, ECOFYS (2014) also recognises that the use of these resources will remain limited by economic, technical and political barriers. Active control of intermittent RES requires specific technical equipment, while the opportunity cost of curtailing "free" generation by intermittent RES will be high. The potential of demand-responses is very high but the necessary investment in IT infrastructure, the constraints due to the primary use of these devices, and data security concerns could be significant barriers to its development. Finally, there is still no business-model for electric vehicles. Yet, the potential of these resources is clear, and is recognised by many as a potential game-changer. Boot et al. (2014) for instance recall that 25% of frequency regulation is provided by demand-side integration in New England and Texas. This success has allowed Texas to postpone the implementation of capacity payments, while the significant share of demand-side resources in the capacity remuneration mechanism that is now in place in PJM has allowed reducing costs drastically.

3.3.2 Provided the right framework is implemented

3.3.2.1 A retail market design that allows the development of distributed resources

The current retail market design in Europe is based on the assumption that the demand of electricity consumers has very little or no elasticity. As a result, supply contracts typically offer unlimited electricity supply to their consumers, and share the balancing responsibility between suppliers and the TSO (He et al., 2013). This assumption has severe consequences for the development of active control of distributed resources.

First of all, the balancing costs are not made explicit to consumers (or prosumers). He et al. explain that consumers are not aware of the concept of balancing, nor of the financial consequences of imbalances. Individual real time imbalance often cannot be measured, and costs are hence spread over all the customers who pay a flat rate per kWh consumed. Moreover, suppliers only pay part of the costs created by imbalances: typically, they are charged the activation costs of the tertiary reserves but not the costs of reserved capacity.

Second, consumers are also deprived of an opportunity of expressing their willingness to pay for electricity and hence to value their flexibility (He et al., 2013). By default, all consumers are provided with the highest security of supply, whatever the state of the system (such as for instance the availability of intermittent RES). This has been identified as a fundamental shortcoming of retail electricity markets by Ambec and Crampes (2012) and Chao (2011). As explained in section 3.1.1.2, consumers cannot distinguish the time when energy is produced at low cost by available intermittent RES without dynamic retail pricing, which prevents an efficient market-based optimisation of the energy mix. Similarly, consumers cannot be compensated for reducing their imbalances as long as their imbalances are not measured.

The current retail market design has therefore not been conceived to ensure an efficient behaviour of consumers. He et al. argue that it would be necessary that consumers express their willingness to pay (or offer) energy in real time. This does not mean that consumers must necessarily be exposed to price and volume-risk. Consumers could either hedge these risks in a forward market, or delegating this task to an intermediary (e.g. the supplier, a consumer cooperative, or a third party). However, having a real-time retail market as a base for innovative contracts is a prerequisite to efficient use of distributed resources.

Similarly, network tariffs should become cost-reflective. Traditionally, congestion occurred in distribution networks at times of peak demand, and hence high electricity prices. This correlation between congestion and peak prices reduced the need for a specific signal not to consume energy in order to reduce congestion. However, congestion patterns at the distribution level will increasingly fluctuate with a high share of distributed intermittent RES. In particular, there could be congestion when the feed in by intermittent RES is high and hence when electricity prices are low. Distribution tariffs should then reflect the state of the network and deliver price signals that would not always match the price signals of energy suppliers. According to Eurelectric (2013), the current most common fixed volumetric network tariffs only give incentives to reduce overall consumption regardless of the time: they do not reflect marginal costs and they do not promote efficient demand response. Similarly, Ruester et al. (2014) claim that an overhaul of the current paradigm for network tariff design is needed, so as to convey efficient signals to all the agents connected to the distribution grid. Indeed, for (Ruester et al.), the old paradigm that had been conceived for pure consuming agents does not hold anymore: volumetric tariffs, applied uniformly over the whole distribution system, would lead to increasing cross-subsidisation as distributed intermittent RES develop. Of course, it is not easy to allocate distribution costs, and in particular to allocate the residual costs that are defined by Brown and Faruqui (2014) as the difference between long-run marginal costs and the total approved revenue of the DSO. Brown and Faruqui show that none of the possible pricing schemes can be compatible with three key prerequisites: efficiency, fairness, and gradual evolution of tariffs. However, more capacity-based tariffs or time-of-use tariffs are more cost-reflective and would encourage efficient use of the network capacity by consumers and distributed resources. The (positive or negative) contribution of grid users to local distribution peaks, and their contribution to losses should in particular be taken into account (Ruester et al., 2014).

3.3.2.2 Developing the adequate environment for active control of distributed resources

The need for a diversity of approaches

Apart from changes to the retail market design, an active management of distributed resources will require the development of an adequate set of intermediaries between the consumers and demand response procurers (e.g. the TSO), as well as an adequate set of contracts. He et al. (2013) developed an analytical frame for demand response, that can be extended to distributed generation resources.

He et al. identified five different types of consumer loads. Load can be storable, i.e. decoupling power consumption from the use, or not. It can be shiftable, when the service can be moved in time without affecting the service, or not. Load can also be curtailable, when the service cannot be shifted but can be interrupted. Finally, the base load cannot be interrupted or shifted. Finally, there is a negative load: self-generation. These five types of consumer loads are depicted in Figure 15. Note that distributed generation can also be storable (e.g. PV with storage), curtailable (e.g. wind turbines with control system) or not (wind farm without control system).

Consumers and distributed producers differ a lot in terms of properties of their load and production mix (He et al., 2013). They also differ in term of preferences: they might be more or less risk-averse (in terms of price and/or volume), able to handle complexity or not, attached to conserving their autonomy and privacy or preferring automation. This diversity of load and preferences will require a similar diversity of contracts: curtailable load/generation can respond to dynamic pricing; shiftable load/generation that requires planning to be shifted fits time-of-use tariffs; Storable load/generation can easily be controlled directly by a third-party. It is therefore important to offer ‘prosumers’ the range of contracts that can fit their different needs and preferences, while making sure that contract comparison tools are developed to protect consumers.

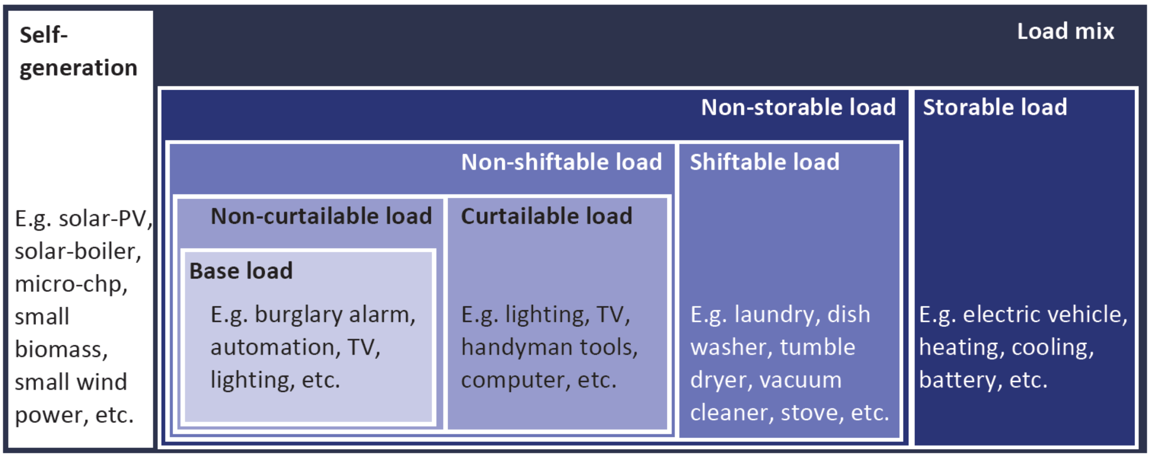

Figure 15 The five different types of consumer load. Source: He et al. (2013)

Because different intermediaries might have an appetite for different contracts, a wide range of contracts will require a wide range of intermediaries such as the suppliers (including integrated supplier-DSOs), third-party (such as ESCOs or aggregators), or consumer cooperatives. Indeed, these intermediaries will differ in terms of openness towards the provision of services, costs of trade, business orientation and competitive pressure (He et al., 2013). Suppliers sell energy and some innovative services might be conflicting with their core business-model, while consumer cooperatives might be reluctant to implement very risky services. Their skills defer as an intermediary: suppliers might have more experience and economies of scale, while cooperatives are formed of untrained customers. Third-parties and the supplier are profit-based, while cooperative are non-profit entities. Finally, these actors might face different competitive pressure, and hence different incentives to share profits with consumers.

It is therefore crucial to avoid any hindrance to the development of an adequate range of intermediaries, which would in turn result in preventing the development of an adequate range of contracts and services, and would eventually limit the development of decentralised resources. A first prerequisite is hence to avoid market power abuse by a dominant intermediary. He et al. (2013) identified three situations in which dominance by a single intermediary could occur: market power of a dominant supplier in the supply market may be transferred to the market of distributed resources management; an integrated supplier-DSO with the advantages on data access and existing contractual arrangements could become the dominant intermediary; ownership of the smart appliances and enabling infrastructure could give an intermediary deploying them a significant advantage. The risk of market power abuse by a dominant intermediary could be mitigated by opening the balancing market to residential demand-response. Ruester et al. (2012a) for instance identified a need to release rules such as minimum bidding requirements, minimum bid duration, or the obligation to provide symmetric up- and downwards bids, to allow small decentralized market players to participate in balancing markets.

Which role for the DSOs?

It is of course important to ensure that grid users receive efficient incentives, via grid tariffs and supply contracts. However, it is also crucial to ensure that the DSOs receive efficient incentives via their regulatory framework. It is not clear today how the penetration of intermittent RES will impact the operational expenditures and capital expenditures of DSOs. De Joode et al. (2009) shows how the penetration of RES can initially reduce the operational expenditures of DSOs (mainly due to decreasing losses) but then increases operational expenditures at higher penetration levels. Several studies show that the capital expenditures of DSOs could be reduced by deferring investment when active management of distributed resources is implemented. On the other hand, higher capital expenditures could be necessary to connect these resources and reinforce the grid where needed.

For Ruester et al. (2014), it is therefore important to establish a sound regulation that would take into account changing structures of the TSO expenditures, including new types of costs. It is also crucial that regulation allows the optimal trade-offs between CAPEX and OPEX to be made, and that innovative solutions can be implemented. For instance, Cossent et al. (2009) explains that in many countries, the development of distributed generation is not even considered as a distribution cost driver.

As the roles of the DSO evolves, it is also necessary to review its boundaries vis-à-vis the TSO (see section 3.2.5) and its boundaries vis-à-vis the market (Ruester et al., 2014). The role of DSOS in providing number of new services, such as ownership and management of metering equipment and charging infrastructures for electric vehicles, or data handling, flexibility provision and energy efficiency, must be analysed (Oosterkamp, 2014). These new services might be offered by the DSOs if the right incentives are implemented, or by other regulated or commercial entities. Ruester et al. (2014) show that the suitability of a certain model will depend on economies of scale or scope, uncertainty regarding the best technology, and concerns of market power abuses. Oosterkamp (2014) detail further the monopolistic and competitive characteristics of these services. On the one hand, public good characteristics of network and system management, as well as significant economies of scale might imply an extension of the role played by the DSOs. On the other hand, the potential for innovation and the diversity of flexibility products and providers impose the need not to foreclose markets. Two potential market structures could hence emerge to unlock the potential of distributed resources, with their pros and cons (See Figure 16). It is however clear, that as the share of distributed resources grows and new services emerge at the distribution level, the effects of limited unbundling will also grow. Ruester et al. (2014) insist on the need for stricter implementation of unbundling requirements and market transparency measures as more responsibilities are given to the DSOs.

DSO market structure:

- Uncoordinated procurement of flexibility services
- Integrated infrastructure model
- Regulated DSO data handling model

Vs.

Liberalised market structure:

- Coordinated procurement of flexibility services
- Independent e-mobility model
- Liberalised Data Access-point Managers model

Figure 16 **Possible market structures for the provision of new services at the distribution level. Source: own depiction based on Oosterkamp (2014)**

3.4 Conclusion: three overlapping toolboxes

Each of the three toolboxes that we identified in the previous sections can contribute to solving some of the key challenges described in section 2. Of course, they also come with secondary effects that can contribute to worsening other challenges. The development of distributed resources can make grid expansion at the transmission level more difficult to plan; coordination tools such as capacity remuneration mechanisms might distort the provision of flexibility. We describe the contributions of the three toolboxes to the four key challenges in Table 7.

Table 7 Potential contribution of each set of solutions to the four key challenges

Challenges	Contribution of wholesale market evolutions	Contribution of coordination tools	Contribution of distributed solutions
Resources Adequacy	✓ Allowing resources to earn scarcity rent ✓ Complementary revenues from well-integrated balancing markets ✓ RES market integration can reduce uncertainty	✓ Better coordination of generation assets can reduce uncertainty and ensure adequacy ✓ Coordination of transmission investment and system operations at the European level allows a more efficient multinational approach to resources adequacy	✓ Distributed resources and demand response can contribute actively to resources adequacy But ensuring a stable revenues stream to assets that will be only used as back-up of distributed resources might prove challenging
Need for flexible resources	✓ Cost- reflection and remuneration of flexibility value	✓ The development of flexible resources can be ensured by procurement through dedicated mechanisms BUT it might be more restrictive and hence more expensive than a market-based procurement	✓ Distributed resources and demand response can also be a source of flexibility
Efficient grid expansion	✓ Stronger locational signals in the wholesale market might reduce the need for grid expansion	✓ Coordination tools between generation and transmission assets as well as between the different transmission operators allow more efficient grid expansion	✓ The development of distributed resources might reduce the need for grid expansion BUT it creates higher risks of stranded transmission assets as consumers "leave the grid"
System operation at the distribution level	✓ Cost-reflection and transparency in the system costs might induce the development of efficient distributed solutions	✓ Coordination tools between transmission and distribution network operators will be needed to handle local issues efficiently.	✓ The development of distributed resources will give many options to system operators at the distribution level

Some of these solutions are partially substitutes: the coordination of generation investments can for instance be ensured by dynamic locational signals in wholesale market prices or by different coordination tools; the recovery of fixed costs of generation assets can be ensured through scarcity pricing or through dedicated capacity remuneration mechanisms; similarly, flexibility remuneration can be delivered via price differentials in the wholesale markets or via dedicated mechanisms.

Some of these solutions are also complementary: section 3.1 explained how a melting-pot integration of intermittent RES would not be possible without implementation of dynamic retail pricing and some form of demand-response; system operation at the distribution level can be tackled by active management of distributed resources by aggregators or DSOs, but it will require further coordination between the TSOs and the DSOs.

Some vision must therefore be established to address the interdependency of the tools described, and ensure that these tools are combined efficiently to address the four intertwined challenges described in section 2.

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