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CEPS Task Force Report

Reforming the Market Design of EU Electricity Markets

Addressing the Challenges of a Low-Carbon Power Sector

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This report is based on discussions in the CEPS Task Force on Reforming the Market Design of EU Electricity Markets. The Task Force met three times between November 2014 and May 2015. Participants included senior executives from a broad range of industries – including energy production and supply companies, energy-intensive industries and service companies – and representatives from business associations, non-governmental environmental organisations, research institutes, think tanks and international organisations. A full list of members as well as observers and speakers appears in the appendix.

Task Force members engaged in extensive debates in the course of three meetings and submitted comments on earlier drafts of this report. Its contents contain the general tone and direction of the discussion, but its recommendations do not necessarily reflect a full common position among Task Force members, nor do they necessarily represent the views of the institutions with which the members are associated.

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The views expressed are attributable only to the authors in a personal capacity and not to any institution with which they are associated.

Key Messages and Executive Summary

In light of the objective to have an entirely carbon-free power sector by 2050, general consensus holds that such a major technological transformation will require considerable investment, some of which will replace carbon-intensive capacity with more flexible, less carbon-intensive forms of power generation. This is reflected in the ongoing EU discussions on wholesale market design, retail market regulation, structural reform of the EU Emissions Trading System (ETS) and the "2030 framework for climate and energy policies." With the drive towards a low-carbon economy, the electricity market needs to make a positive contribution to the successful delivery of these new policy objectives. It is necessary to understand how the low-carbon economy will be brought about, notably what market rules ('market design') will be required and whether there is a need to adapt the current framework.

Making the market fit for the low-carbon transition

At the core of the current market design is an energy-only market, which remunerates energy delivered. Such a market attracts investment in new capacity both through direct and indirect reliance on price signals. Indirect reliance refers to market participants entering into commercial arrangements with each other in order to hedge their exposure to price and volume risk. Historically, unexpected policy interventions, erroneous demand expectations and long lead times for planning and building new capacity have led to boom and bust cycles, i.e. times of overcapacity alternating with times of scarce capacity. The ETS has been designed as the principle tool to ensure that investments are increasingly low-carbon, by providing a price signal for the long-term scarcity of carbon. Moreover, forward markets exist, offering the possibility to trade long-term contracts for physical delivery or financial hedging against the prices of short-term markets. Currently, the commitment periods available for such contracts seldom go far beyond one year and the liquidity of forward contracts with a delivery date of more than three years in the future has been negligible.

In the last 15 years, gas and renewables made up 91% of new capacity additions. Yet investment decisions for these two technology groups have not been triggered in the same way. So far, EU member states have primarily relied on dedicated policy instruments to support the deployment of renewables. Thus investments in renewables have mostly *not* been triggered by wholesale price signals based on internal energy market regulation and the ETS.

The challenge of investing in low-carbon

Today, the full costs of low-carbon technologies are above wholesale market prices. This raises two questions. The first question is how low-carbon investment will be triggered in the future. Secondly, even if this gap between full costs and market prices is closed – as a result of further decrease of technology costs or an increase in carbon, coal and gas prices – the question of efficient financing remains. Many stakeholders and some EU member states argue that the cost structure of some low-carbon technologies requires a different investment trigger than the wholesale price. Technologies such as wind and solar have high upfront costs and close-to-zero variable production costs. This means that capital costs have a proportionally greater impact on the total costs of such technologies than they have on coal or gas generation. At the same time, there are two side effects of using dedicated support policies. First, when the market is already well supplied and demand is not growing,[1] they add to surplus capacity, reducing the demand for electricity generated from existing conventional sources. Second, there is more fluctuation of demand for electricity from conventional sources, because renewable generation depends to some extent on weather conditions.

The challenge of investing in conventional resources

Decreasing hours of operation of conventional power plants create a need for a different mix of conventional generation technologies, as these do not just differ in their variable production costs but also in their fixed and investment costs. So-called 'base-load' capacity is used to cover the minimum continuous level of electricity demand, as it has relatively low variable but high fixed and investment costs. Consequently, when hours of operation diminish, some base-load would be expected to be replaced with capacity that has lower fixed costs (so-called 'mid-merit' and 'peak-load' capacity).

The business case of peak-load is generally considered challenging, because investment costs have to be recovered from a low number of hours of operation. What's changing with renewables is that (i) more of these units will be needed and (ii) the exact amount required is subject to greater uncertainty than today due to the weather-dependent availability of renewables. Moreover, in the competition for the remaining market share of mid-merit technologies, the more flexible sources with their higher production costs are currently losing out and the business case for them is becoming more challenging.

Solutions

Stakeholders generally agree that there is a lack of proper implementation of the existing framework. Among the shared recommendations are:

- Fully and properly implement the current market design (standardisation of products, harmonisation and relaxation of price caps,[2] improved price formation in energy and balancing markets, coupling of intraday and balancing markets).
- Improve the functioning of short-term markets to allow for a level playing field between demand, conventional supply and renewable supply.

[1] Overall EU electricity demand has been rather stagnant over the last three years, despite the fact that the EU economy has started to recover (in terms of GDP growth). Part of the 2008-09 decline may thus be structural.

[2] More recently, 12 EU member states have agreed not to introduce any *legal* price caps (see BMWi 2015). For technical reasons, power exchanges will still have to define a maximum market price, i.e. a *technical* price cap.

- Expose every generator to the same obligations and risks.
- Strengthen the EU ETS in order to provide more predictable long-term signals; this will also serve as a market-exit signal for carbon-intensive capacity. Different views exist on how to best achieve this.
- Remove market-exit barriers where they exist.

These measures will address the existing shortcomings, to an extent. Coupling markets and harmonising price caps will lead to a better use of cross-border resources, thus increasing market *efficiency*. Removing price distortions, exposing all market participants to the same risks and removing market-exit barriers will improve price *formation* in energy and balancing markets. In order for these measures to be effective, however, market rules have to be set EU-wide or at least regionally. They will also need to be implemented.

Market-driven investments require a stable and predictable long-term framework. The EU challenge will be to instil confidence that these rules are in fact stable and that market outcomes, especially in terms of wholesale prices and security of supply levels, will not eventually trigger public intervention. In order to achieve this, it is important that – irrespective of which approach will be chosen – this framework is based on evidence and, ideally, enjoys the support of the broadest possible stakeholder group.

Important open questions

There was controversy over two critical points: i) how to treat overcapacity and ii) the potential need for capacity mechanisms to support investment, i.e. *explicitly* remunerating availability.[3] The Task Force discussed them in depth but no consensus was possible. The report therefore describes the options. CEPS will return to these points separately.

These controversies are central to the debate of the market design fit for the transition to a low-carbon economy, i.e. a stable and predictable long-term framework conducive to investment. On the first point, i.e. overcapacity, some argued that policies are needed to accelerate the retirement of capacity, mainly base-load capacity. Others held that the market eventually will achieve this on its own, provided there are no exit barriers. Similarly, there was no agreement on the second point – the need for capacity mechanisms. From the perspective of the EU's internal market, there is political urgency to settle these two controversies, however. Some member states have started putting national measures in place, for example in the fields of capacity markets, long-term contracts or approaches to address overcapacity. At this point, it is essential to understand how differing national choices can co-exist and what level of standardisation and harmonisation is required. Otherwise, the likelihood of market fragmentation increases.

[3] Evidence and analysis are provided in chapter 5. It is important to note that different member states will take different views on whether the question of how to trigger investment is more important than the question of how to deal with overcapacity.

1 Introduction

The EU has repeatedly confirmed its position that the global, annual mean surface temperature should not increase by more than 2°C above pre-industrial levels. To develop consistent emissions reduction trajectories up to 2050, the European Commission has worked out road maps. Many member states as well as industry sectors have done the same.

One of the recurrent key messages of all road maps is the major contribution of the EU's power sector. According to the EU low-carbon road map,[4] its role in final energy consumption would have to double and moreover be entirely carbon-free by 2050 to achieve the EU's agreed objective of reducing greenhouse gas emissions domestically by 80-95% compared to 1990. Such a major technological transformation can only succeed with continuous investment in low-carbon technologies and a phase-out of existing, carbon-intensive technologies.

Following the 2009 "2020 climate and energy package", there had been hope that especially the Directives on the Internal Energy Market together with the ETS, would lead to convergence and integration of member states' energy markets, fostering affordability and security of supply. The ETS would provide the price signal to modernisation by driving low-carbon investment, fuel switching and other efficiency measures, thereby reinforcing security of supply and enhancing competitiveness. The reality is different. The carbon price signal of the ETS has proven to be too weak to have a lasting effect either on new investment or on the retirement of carbon-intensive capacity. Moreover, when implementing the 2020 climate and energy package, member states have taken different national policy approaches that are sometimes inconsistent and incompatible with each other.

Unilateral national action has also hindered the gradual completion of the internal market for electricity, envisaged to be completed by the end of 2014. A lack of proper implementation of internal market rules, combined with the – politically desired – rapid expansion of new, largely intermittent renewable energy sources, has made many stakeholders raise the question of how EU power markets should be designed to ensure the achievement of EU energy and climate policy objectives. Opinions diverge over whether the solution lies in a better implementation of the current rules or a new market design.

The European Council confirmed its previous emission reduction trajectory in October 2014, when it decided on a set of targets for 2030 by adopting the "2030 framework for climate and energy policies."[5] As a result, the share of renewables is expected to considerably increase even until 2030. If the power sector continues to contribute in a similar way as today, the

[4] See COM(2011) 112 final.

[5] The European Council decision includes binding targets for (i) domestically reducing greenhouse gas emissions by 40% by 2030 compared to 1990, (ii) increasing the share of renewables to 27%, (iii) an indicative target to improve energy efficiency by at least 27% compared to 'business-as-usual' projections of the future energy demand, and (iv) a 15% interconnection target.

overall 27% renewables target would translate into a target share of at least 45% of renewable electricity by 2030 compared to a share of 25% in 2013.[6]

This CEPS Task Force Report focuses on whether there is a need to adapt the EU's electricity market design and if so, the options for doing so. In a first step, it will analyse the current market trends by distinguishing between their causes and their consequences (chapter 2). Then, the current blueprint of EU power market design – the target model – is briefly introduced (chapter 3). In chapter 4, shortcomings of the current approach are identified, followed by a discussion of the challenges in finding suitable solutions. Chapter 5 offers an inventory of solutions differentiating between recommendations shared among Task Force members and non-consensual options.

Appendix 1 consists of a Glossary of Technical Terms and Abbreviations. Appendix 2 lists all Task Force members.

[6] Source: Eurostat (2015).

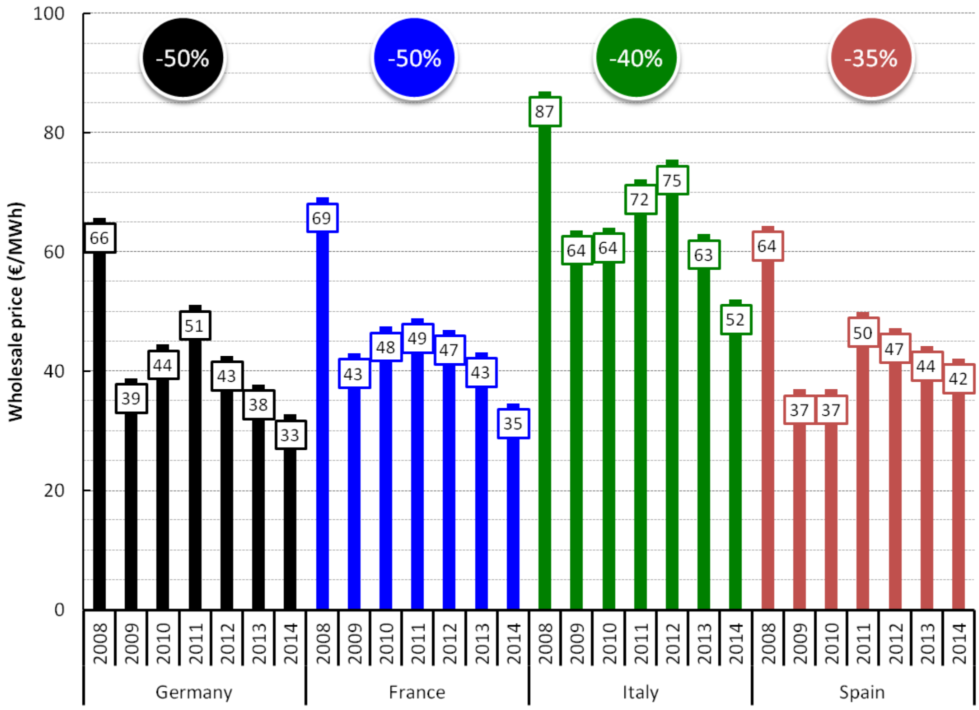
2 Shared analysis of current market trends

The aim of this chapter is to provide an analysis of current market trends by carefully distinguishing between the underlying causes of these developments and the subsequent consequences they have for market participants and social welfare. This will help to distinguish between causes that entail a failure and, hence, need to be tackled in a potential policy intervention and causes that should be accepted as normal market dynamics.

2.1 *Recent market trends: Decreased wholesale prices as well as increased spread between retail and wholesale prices*

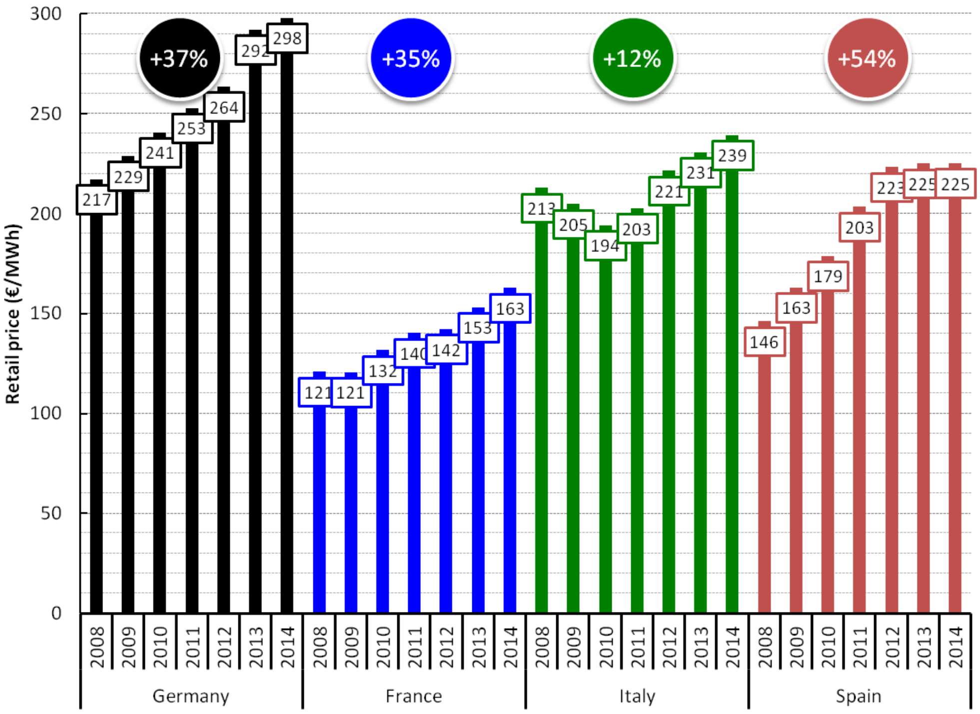
The dilemma of the current EU power market design can be better understood by analysing two opposing trends: on the one hand, we have observed a strong decrease of wholesale market prices from 2008 to 2014 in many EU member states (see the examples of Germany, France, Italy and Spain in *Figure 1*); on the other hand, retail market prices have *increased* in the same period of time, especially in the residential sector[7] (see *Figure 2*).

Figure 1. Wholesale power prices[8] in selected EU member states (2008-14)



[7] Retail prices for industrial consumers are typically lower than for residential consumers.
[8] Sources: EEX (2015), GME (2015), OMEL (2015).

Figure 2. Retail prices for households in selected EU member states (2008-14)



Source: Eurostat (2015), annual electricity consumption between 2,500 and 5,000 kWh, nominal prices.

2.2 Causes

Wholesale market prices

The main causes for the decrease of wholesale prices from 2008 to 2014 are 1) decreased coal prices,[9] 2) an oversupply of carbon allowances resulting in a decrease of carbon allowance prices[10] and 3) overcapacity of power production plants, putting downward pressure on wholesale prices. Overcapacity was, in turn, caused by lower-than-expected electricity demand, over-investment, the injection of new capacity through dedicated policy instruments[11] and the continuing improvement in the field of coupling national electricity markets.[12] While there is general consensus on these three causes, Task Force members do not agree which of these causes has had the greatest impact on the decline of wholesale prices.

[9] The German import border price for hard coal can be used an indicator for this decrease. From 2008 to 2014, it decreased by 35% (€13.8 per MWh_{th} to €9 per MWh_{th}). A major cause for this price drop is the reduced demand for coal in the US power sector, where coal was mostly replaced with cheap, unconventional gas.

[10] The average price for carbon allowances was €6 per tonne in 2014, down from roughly €23 per tonne in 2008 (-73%).

[11] This is sometimes referred to as 'merit-order effect'.

[12] Market coupling leads to more efficient use of cross-border resources. Provided that there is sufficient interconnection and that demand peaks do not occur simultaneously, this can put downward pressure on prices.

Lower coal prices imply lower production costs for coal-fired power stations. This affects market prices, when a coal-based plant sets the market price. In the examined period, the price-setting technology has either been gas-based or coal-based during the vast majority of hours.[13] Whether coal or gas sets the market price depends on the variable production costs for these fuels (including CO_2 costs) and on their respective share in installed *capacity*.[14] From 2008 to 2014, the competitiveness of an average coal-fired power station[15] vis-à-vis a brand-new gas-fired power station[16] has increased. Variable production costs (including CO_2 costs) of an average coal-fired plant decreased from €53 to €27 per MWh in the examined period, whereas production costs of a highly efficient gas-fired power station decreased only from €53 to €41 per MWh. Consequently, countries with a high share of coal-fired capacity in their power system have experienced an increase in the share of coal-fired electricity generation and a decrease in market prices. This development was also facilitated by the low price for carbon allowances.

Causes (wholesale market prices)

- Decreased coal price
- Oversupply of carbon allowances
- Overcapacity (lower-than-expected power demand, over-investment, injection of new capacity through policy instruments, improved functioning of internal market)

Causes (retail market prices)

- Increase in taxes and levies

In general, varying prices for energy carriers such as gas and coal should be considered a normal market development. Market participants have sufficient possibilities to hedge against the volatility of coal or gas prices.

Variations in the price for carbon allowances should also be seen as a normal element of the ETS, which is a volume-based instrument. However, many argue that the main cause of the current oversupply of carbon allowances lies in the absence of supply-side flexibility of the ETS. Since supply of carbon allowances was fixed *ex ante*, the drop in demand (resulting from the 2008-09 economic crisis) led to a decrease in carbon allowance prices. The impact of deploying renewables on the demand for carbon allowances has been limited. This is because the cap of the ETS has been designed to be consistent with the *planned* contribution of renewables in decreasing emissions. Thus only overachieving the targeted contribution would reduce the demand for carbon allowances (see Box 1).

[13] One can argue that a price of zero or negative prices indicate that subsidised renewables have set the price. For Germany, this was the case in around 1% of the hours in 2014.

[14] In practice, this means wholesale market prices reflect the structure of generation *capacity* mix to a certain extent. Italy, for instance, benefits less than Germany from a fall in coal prices, since the thermal generation capacity mix in Italy is not dominated by coal but natural gas. Thus coal is less likely to set the price.

[15] The average conversion efficiency of coal-fired stations in Germany currently amounts to 41%.

[16] The highest conversion efficiency of a gas-fired station (combined cycle) currently amounts to 60%.

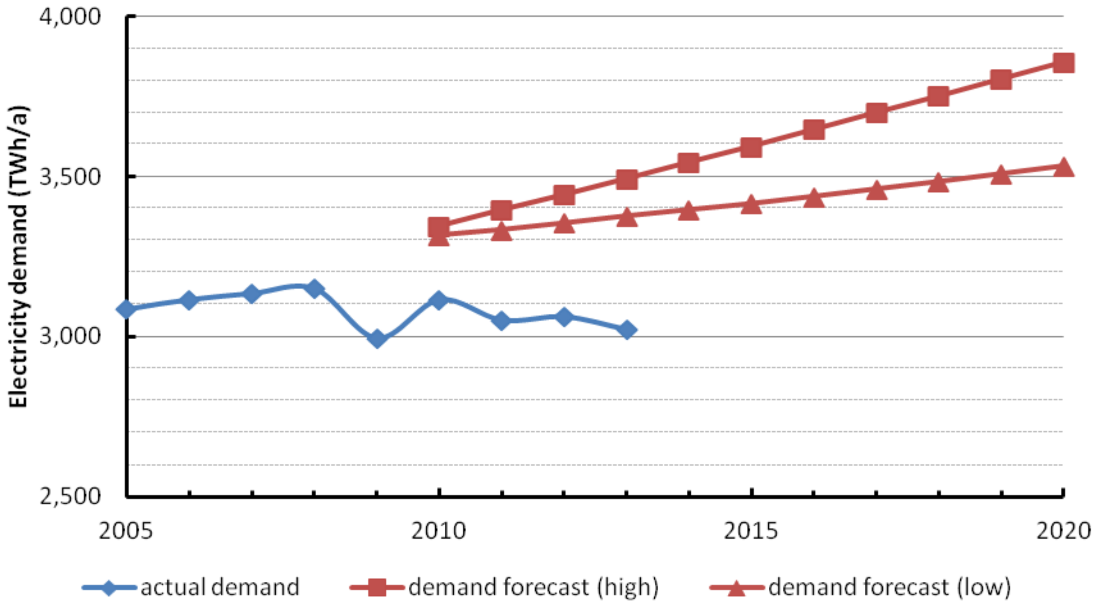
Flexibility on the supply-side would be needed in order to avoid a *carbon lock-in*.[17] To address this, the European Commission is close to adopt the so-called 'Market Stability Reserve', to match the demand variability with a mechanism that should allow for adapting supply to demand, thus allowing volume-based control on the carbon price.

A third cause for the decrease in wholesale prices is overcapacity. The 2008-09 economic crisis was accompanied by an unparalleled drop in electricity demand. At the end of 2012, the electricity demand in the EU-27 was still 3% lower than in 2008. Back in 2008, analysts were expecting an annual growth rate of 1.5% (Capros et al., 2008). Thus the divergence between projected and realised values amounts to roughly 9%.

Demand forecasts were also created by each EU member state in the context of their national renewable energy action plans (NREAPs). These plans had to be notified to the European Commission by 30 June 2010 and contain detailed road maps of how the national, legally binding 2020 target was expected to be reached – distinguishing between contributions of the power, heating and transport sectors. As illustrated in Figure 3, demand had largely been overestimated from the beginning. Apparently, national governments were expecting a quick recovery of the demand after the crisis – a scenario that has not materialised. In 2013, the divergence between planned and actual values amounted to more than 10% in the energy efficiency case (low demand) and to more than 13% in the reference case (high demand). In absolute terms, this gap roughly corresponds to the electricity consumption of the United Kingdom in 2013. Despite the fact that the EU economy has started to recover (in terms of GDP growth), electricity demand has been rather stagnant over the last three years. Thus part of the decline appears to be structural.

[17] In the absence of a clear economic signal for decarbonisation, this term refers to a possible scenario of overinvesting in carbon-intensive technologies in the short term. Given the rather long economic lifetime of assets in the power sector, this scenario entails relatively high emissions in the medium term, i.e. a *carbon lock-in*, unless the installations remain idle or are decommissioned before their lifetime is exhausted, which is considered a waste of economic resources.

Figure 3. Expected vs. actual electricity demand in the EU-28 (2005-20)[18]



A short-term effect of lower-than-expected electricity demand is that units with relatively high (variable) production costs are no longer needed to cover demand, thus lowering wholesale prices. Moreover, some market participants overinvested in new capacity, putting additional downward pressure on prices.

At the same time, we have also observed a massive deployment of renewables as mandated by the Renewables Directive (2009/28/EC), which set targets for the use of renewable energy in each EU member state. National governments subsequently implemented subsidy systems for renewables in order to ensure that their domestic targets are met. Unless other plants are retired, such an injection of new capacity through dedicated policy instruments will have a similar impact on conventional generators: a decline of electricity demand.[19] On the one hand, one can argue that the impact of this deployment was largely to be anticipated, *at the latest* since the 2009 adoption of the "2020 climate and energy package". On the other hand, the power sector is, as of 2013, contributing to the overall 20% target to a greater extent than anticipated in 2010 – albeit counterbalancing the lower-than-expected contribution of renewables in heating, cooling and transportation (see Box 1).

[18] Sources: NREAPs (2010), Eurostat (2015).

[19] The same considerations can be applied to the UK announcement of financing the deployment of nuclear power using a dedicated policy instrument.

Box 1. Deployment of renewables on track as of 2014

An analysis of the 28 national renewable energy action plans (NREAPs) reveals that the increase in *electricity* production from renewable sources has proceeded as projected *in absolute terms* (see *Figure 4*). At the same time, due to the lower-than-expected electricity demand, the share of renewable electricity in total electricity demand is higher than anticipated in 2010. In 2013, the actual share in the EU-28 was 27%, whereas the projected share was 23% for that year, according to the NREAPs.

It is important to note that the increase in other sectors, i.e. heating, cooling and transportation, has not materialised as projected. Most EU member states are especially falling short of the projected share of renewables in transport. Overall, i.e. considering all sectors, the actual share of renewables in gross final energy consumption amounted to 15% in 2013, which is just one percentage point above the projected share for that year (14%).

While the EU as a whole is on track, the situation varies from member state to member state. To reach their respective national target for 2020, member states may have to adapt their support strategy but could also make use of cooperation mechanisms, namely statistical transfers.

Figure 4. Expected vs. actual electricity production from renewable sources in the EU-28 (2005-20)

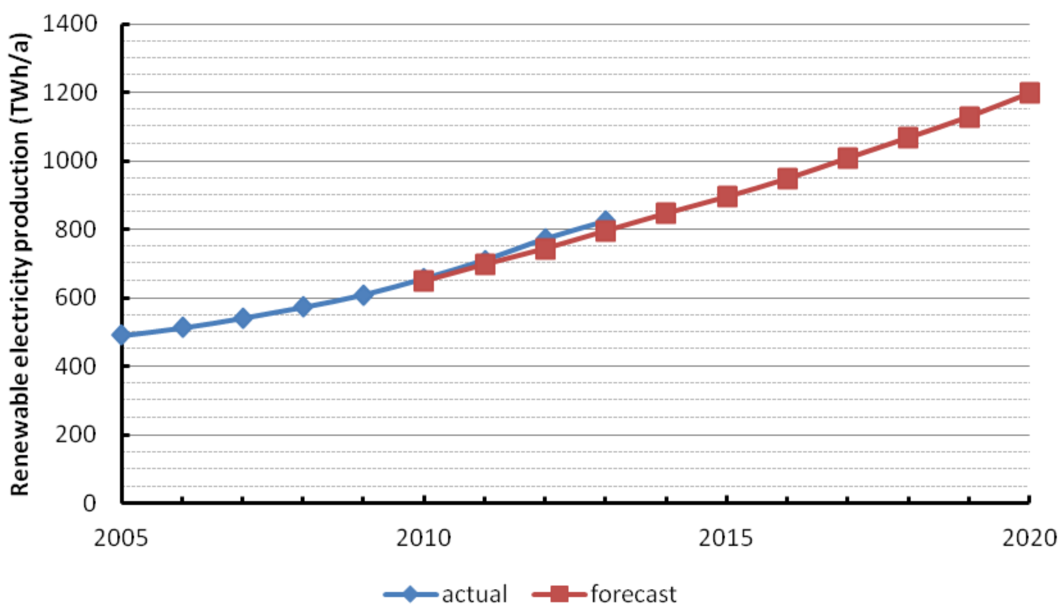
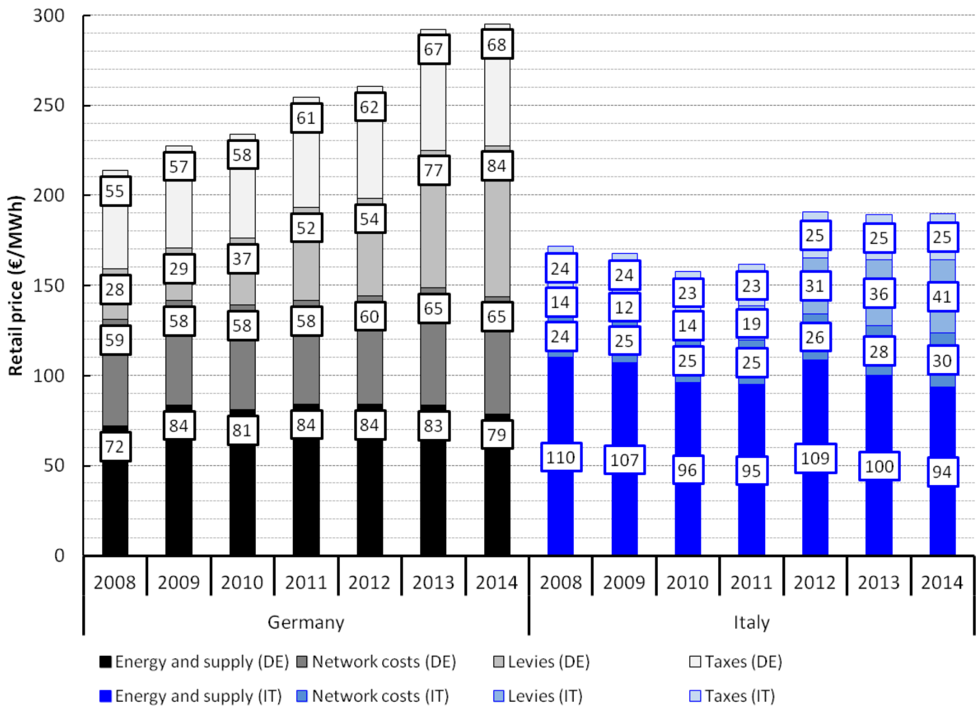


Figure 5. Components of retail prices for residential consumers in Germany[20] and Italy[21] (2008-14)



Retail market prices

A retail price consists of several components. Typically, one distinguishes between production-related costs ('energy and supply'), network costs, levies and taxes. Thus the first component is linked to the wholesale price. National regulation has a significant impact on at least three out of four components. Therefore, conditions vary from member state to member state but also from consumer type to consumer type. For instance, some industrial consumers are granted exemptions from paying certain levies. Nevertheless, by decomposing the electricity bill of residential consumers in Germany and Italy, interesting observations can be made (see *Figure 5*).

In both cases, the increase in retail prices is primarily caused by an increase in levies (+198% in Germany, +189% in Italy) and to a lesser extent by an increase in taxes (+24%, +6%) and network costs (+10%, +26%). Production-related costs decreased for Italian household consumers (-15%), while they increased for German household consumers (+9%). As a result, the cost component related to the wholesale market price has less weight in the end-consumer price than in 2008.

A similar trend, i.e. a decreased importance of the wholesale price, can be observed for electricity consumers throughout the EU, as indicated by a recent study of Eurelectric.[22] In some countries, tax increases have contributed more to this development than in Italy or

[20] Source: BNetzA & BKartA (2014), annual consumption: 3,500 kWh.
[21] Source: AEEGSI (2014), annual consumption: 2,700 kWh, peak load: 3 kW.
[22] See Magyar & Lorubio (2014).

Germany, where an increase in levies has been the main driver. An example is Portugal, where VAT alone increased from 6% to 23% in 2011. For the EU as a whole, network tariffs have increased moderately by 17% from 2008 to 2012.[23] In the same period, transmission-related costs have risen by less than 12%, which implies that the increase in distribution tariffs has been greater than the increase in transmission tariffs.[24]

2.3 Consequences

Consequences for generators

Compared to 2008, conventional generators 1) sold electricity at a *lower price* and 2) sold *less electricity* in 2014. The latter is caused by the contraction in market share. Electricity generated from conventional sources has either been replaced by electricity from renewable sources or is simply not needed anymore because of lower electricity demand.

Consequences

- Generators: selling at lower prices, selling less electricity
- Higher net support costs for renewables
- Disincentive to invest in retail storage and demand-response

For generators, selling electricity at a lower wholesale price *can*, i.e. does not necessarily, mean that their *profit margins*[25] go down. As outlined in the previous section, lower prices for coal or gas are *one* possible cause for lower wholesale prices. In this case, lower wholesale prices are accompanied by lower production costs for some generation technologies. The exact impact on a generator's profits depends on his individual fuel mix and should be considered a normal market risk, which does not justify the need for policy intervention. For the price of carbon, the situation is different, as the lower price is to a great extent a result of an ETS design not fit for its purpose.

In a market that is already well served and where demand is not growing, dedicated support policies effectively reduce the demand for other sources of power generation. Therefore, the impact on a conventional generator's profit margin is always negative in the short term. Moreover, some power plants become unprofitable to run and are consequently mothballed or decommissioned, especially where no market-exit barriers exist. In order for overcapacity to be temporary, excess conventional capacity must be *allowed* to retire, however.

The relevant design question for the short term is whether the current market rules ensure that (1) surplus capacity can be retired, (2) the 'right' capacity[26] is retired and (3) sufficient capacity stays online. Following the market mechanics and given the current spread

[23] Ibid.
[24] See ENTSO-E (2014).
[25] We use the term "profit margin" as a synonym for "gross margin" throughout this report. The gross margin is defined as the differential between the market price and the variable production costs of a power plant. Thus it is used to cover fixed maintenance costs and recover investment costs.
[26] In order to restore market equilibrium, it is essential that there is a right mix between base-load, mid-merit and peak-load capacity (see section 4.2, "Dealing with overcapacity").

between coal and gas prices as well as present carbon allowance prices, gas-fired power stations are more affected from this development than coal-fired plants. This is a result of variable production costs of gas-based stations being higher despite being less carbon-intensive than coal. Some market participants consider this an undesirable development, since a thermal generating mix dominated by carbon-intensive fuels is inconsistent with meeting established policy objectives for 2030 and beyond.

Higher net support costs for renewables

A decrease in wholesale prices can increase the net support costs for renewables (depending on how the support system for renewables is designed), which in turn increases retail prices. As discussed in the previous section, the increase in retail prices was mainly caused by an increase in taxes and levies. It is difficult to provide an analysis for the EU as a whole due to the fact that the exact causes differ from member state to member state and from consumer type to consumer type. Yet evaluating the consequences for residential consumers in Germany and Italy reveals some insight into the interconnection between wholesale and retail prices and how wholesale prices affect net support costs for renewables.

For households in Italy and Germany, the increase in levies was mainly needed to finance the deployment of renewables through dedicated support systems. In 2014, the surcharge for financing renewables amounted to €62 per MWh for German households (75% of all levies) and to €34 per MWh for Italian households (85% of all levies). However, the decline of wholesale prices also plays a role, as this decline results in a reduced market value of renewable electricity. In Germany and partly in Italy, support systems for renewables are designed such that they allow investors to recover their full costs.[27] In practice, this means plant owners are compensated for the difference between the wholesale market price and a fixed remuneration level.[28] This differential is referred to as *net support costs* and is passed on to consumers. Therefore, the *net* support costs for renewables would have been lower without a decline of wholesale prices.

This effect can be assessed quantitatively, provided that a detailed decomposition of costs and revenues of the support system is available – broken down into all supported renewable energy sources. This is the case for Germany starting from 2010.[29] Evaluating reports of German transmission system operators (TSOs) reveals, for instance, that the average market

[27] This is generally the case for support systems based on a feed-in tariff or a contract for difference (currently active in Germany and also partly in the UK and Italy) but not for a support system based on green certificates (currently active in Norway and Sweden and also partly in Italy).
[28] Strictly speaking, the above-mentioned case only applies to a contract-for-difference system, where generators receive a premium on top of the wholesale market price. In a feed-in tariff system, generators are not exposed to market prices. However, in that case a third party such as the grid operator is in charge of the commercialisation of the electricity produced. This party is compensated for the gap between the market price and fixed feed-in tariff. As in a contract-for-difference system, this differential is typically passed on to consumers.
[29] See 50Hertz et al. (2015).

value of solar power amounted to €42 per MWh in 2014, down from €64 per MWh in 2010.[30] Assuming wholesale market prices from 2010, the necessary net support costs could have been €2 billion lower in the last year. As a result, a reduced levy of €57 per MWh (instead of €62) would have been sufficient to allow renewable energy investors to recover their full costs.

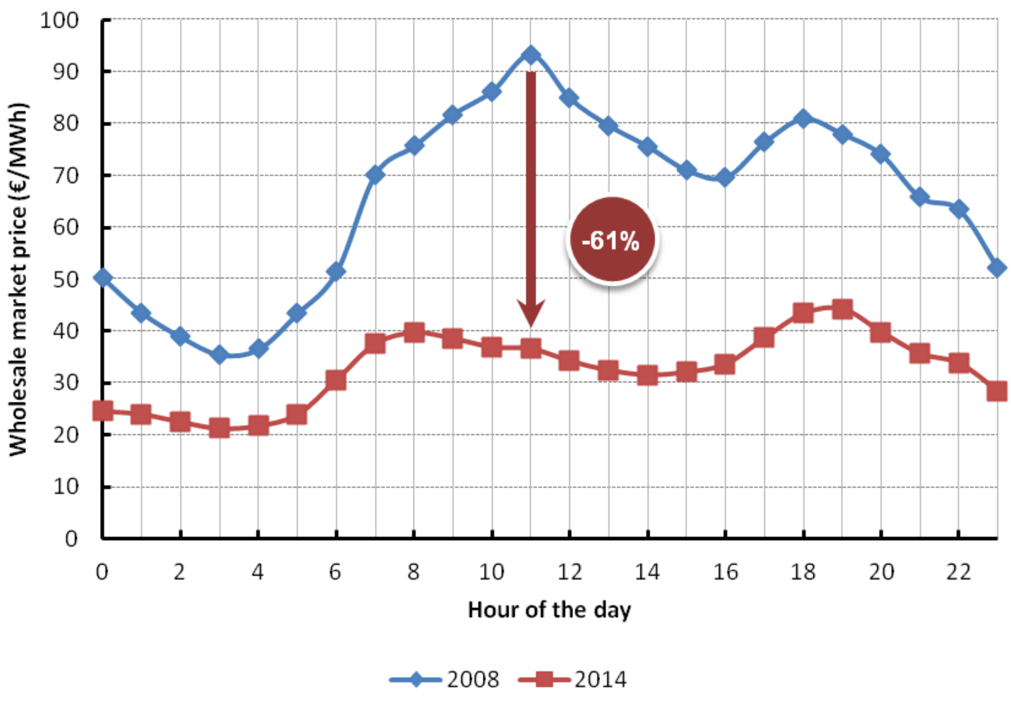
Put differently, a possible future increase in wholesale prices would *partly* be counterbalanced by a decrease of the levy used to finance the deployment of renewables.

Disincentive to invest in retail storage and demand-response

Storage generates revenues by charging during times of low prices and discharging during times of high prices. Similarly, demand-response can create value by shifting consumption from times of high prices to times of low prices.

The main challenge for storage and demand-response is that today's wholesale prices are relatively *low* and *flat*. Moreover, the retail pricing *mechanism* has an impact on the economic viability of storage and demand-response. To illustrate this in more detail, it is useful to distinguish between (1) bulk storage operating in the transmission grid, (2) 'retail storage' operating in the distribution grid, (3) demand-response and (4) local storage strictly used to optimise self-consumption.[31]

Figure 6. Wholesale market prices grouped by hour of the day (Germany, 2008 and 2014)



[30] The main underlying figures for this assessment are: (1) expected base-load price for 2010 (in 2009): €54 per MWh, (2) expected base-load price for 2014 (in 2013): €41 per MWh, (3) expected market value coefficient for solar in 2010: 120% and (4) expected market value coefficient for solar in 2014: 101%.

[31] This refers to the consumption by auto-producers of electricity, which they themselves produce.

Today, the dominant bulk storage technology is pumped hydro. It is typically connected to the transmission grid and therefore not considered as a 'normal' consumer, i.e. no retail taxes and levies arise when charging a pumped hydro station. Depending on national regulation, grid fees may have to be paid. Thus bulk storage is primarily driven by the dynamics of *wholesale* prices. In some countries, peak prices have decreased more than valley prices at wholesale level. This means that the spread between high prices (occurring at noon) and low prices (occurring at night) has declined (see *Figure 6* for an illustration of the German case). As a result, it has become increasingly less attractive to *operate existing* bulk storage; investing in new units is considered economically unviable in countries where price spreads are the main source of income for storage.[32]

For batteries operating in the distribution grid and offering services to end-consumers, retail prices apply. This means that every time such a storage unit is charged, a price that includes taxes, grid fees, a surcharge for renewables and other levies has to be paid. As a result, the economic benefit of operating retail storage today is lower than in 2008 – not just because of reduced price spreads at wholesale level but also because the share of taxes and levies in the overall price has increased. At present, there is virtually no storage at retail level. Regarding economic viability, similar considerations can be applied to demand-response, provided that consumption is not just reduced in times of high prices but shifted to periods with low prices.

A potentially emerging technology is local storage. This refers to batteries that are used to optimise self-consumption, i.e. used to shift electricity produced locally, for instance from solar panels. In this case, storage is not exposed to retail prices. If retail prices continue to rise, it may become increasingly beneficial to invest in decentralised generation and local storage, depending on the retail pricing mechanism and whether grid tariffs are applied in a way that reflects the cost structure of grids.

On the one hand, the current retail pricing mechanism is a disincentive to invest in retail storage or demand-response, because taxes and levies are mostly allocated based on the electricity *consumed*. On the other hand, such a pricing mechanism can be considered as an incentive to invest in local storage, i.e. storage located 'behind the meter' to avoid being exposed to taxes and levies. A side effect, however, is that the flexibility of these storage units would not be available to the system, which is undesirable.

In the context of local storage and self-consumption, two well-differentiated issues can be identified, both of them related to a potential misalignment of savings between the system and the end-consumer:

- Retail prices include costs unrelated to electricity supply. As a result, self-consumption leads to potential consumer savings that do not necessarily correspond

[32] Repowering, i.e. upgrading existing stations, is considered economically viable in some cases, notably in Portugal. Moreover, additional sources of revenues, e.g. from providing ancillary services, can make a difference.

to actual system savings, because those costs unrelated to electricity supply will simply be incurred by the remaining end-consumers.

- The retail price structure does not fully reflect the system cost structure. Some system cost components are fixed and not variable costs, i.e. these are not related to consumption. Grid access costs are, for instance, mostly fixed costs. If this is not reflected in the retail pricing mechanism, self-consumption will produce consumer savings that do not necessarily correspond to actual system savings.

3 Current blueprint for EU power market design: the target model

The target model is an EU-wide blueprint for the integration of national and regional power markets. Its main elements are briefly introduced in the following sections.

3.1 Marketplaces

In liberalised energy systems such as the EU, parts of the US, South America or Australia, *short-term* markets for the *physical delivery* of electricity exist. They are considered short-term, which means that the time horizon is one day or less. There is usually a day-ahead and an intraday market, where electricity can be contracted for delivery during the upcoming or the current day, respectively. The day-ahead marketplace is considered sufficiently[33] liquid[34] in most EU member states. This means there is a sufficiently large number of buyers and sellers willing to trade at all times, which is essential for a market to be competitive and efficient. In these markets, generators are remunerated based on energy delivered, while the demand-side is charged for the energy consumed.[35]

Balancing power is needed in any power system to maintain a balance between production and consumption close to real-time. In liberalised power systems, grid operators have to procure this balancing power in a transparent and competitive way, i.e. in balancing power markets. Depending on national regulation balancing power markets sometimes offer remuneration for the availability of power. This is the case for primary, secondary and tertiary reserves in Germany, for example. However, these are short-term contracts with a maximum commitment period of one week and, more important, very small markets with a volume that is in the range of 3-4% of peak demand.

Most liquid marketplaces offer:

- Short-term contracts
- Remuneration for physical delivery

Less common marketplaces for:

- Long-term contracts
- Remuneration for availability

Finally, forward markets exist. These offer the possibility to trade long-term contracts for physical delivery or financial hedging against the prices of short-term markets. The liquidity of these marketplaces can easily exceed the liquidity of day-ahead markets by a factor of 15 to 30. Yet, the liquidity of forward contracts with a delivery date of more than three years in the future has been negligible and the commitment periods currently available for such contracts seldom go far beyond one year.

One reason for this decrease in liquidity is that many EU markets are faced with overcapacity. When there is a lack of demand for new capacity, this is reflected in the liquidity of forward markets. Another reason is that risk premiums grow exponentially with

[33] See ACER & CEER (2012).
[34] In this context, we use the term market liquidity to compare the volume of power traded in a marketplace with the total amount of electricity consumed. This ratio is sometimes also referred to as *churn rate*.
[35] Depending on the supply contract, the demand-side might also be remunerated for not consuming and thus effectively acting as a generator.

the delivery date. There are no suitable *long-term*[36] hedging instruments – neither for relevant production cost factors (price of coal, gas, carbon) nor for the risk of a regulatory intervention. As a result, the current demand of end-consumers for long-term contracts is close to zero.

These four markets – day-ahead, intra-day, balancing power and forward markets[37] – represent the main elements of the so-called 'EU target model' for electricity markets, essentially a blueprint to be implemented by all EU member states.

More recently, some EU member states have implemented or announced their intent to implement capacity markets, i.e. markets that *explicitly* remunerate availability or delivery of electricity in times of system stress (see section 4.2 for a more in-depth overview). These kinds of markets are currently not foreseen in the EU target model. The EU blueprint is based on a so-called 'energy-only market'. This means the energy delivered or consumed is priced, except for balancing power markets where availability might be remunerated explicitly depending on national regulation. It is important to note that availability is *implicitly* remunerated in the current framework (see section 3.3). Yet these revenues might not be sufficient to cover all fixed costs in case of market failures (see section 4.2)

3.2 Market coupling and cross-border transmission rights

Cross-border cooperation and competition has been implemented by coupling national *day-ahead markets*. Essentially, this means generators do not have to decide whether to offer their production capacity to the domestic or a neighbouring market. To this end, the various national market operators combine all demand orders and supply offers. Afterwards, the available cross-border transmission capacity is allocated in such a way that the overall costs to consumers are minimised. Thus physical transmission rights are allocated *implicitly*. As of June 2015, this approach has been implemented in most EU member states.

It is also possible to obtain long-term transmission rights *explicitly*. This can be useful to contract cross-border deliveries of electricity for a period longer than one day. Moreover, it gives market participants the possibility to hedge themselves against congestion costs. Yet transmission rights on national borders can only provide hedging opportunities between two price areas, not on a regional level.

In the current framework, transmission rights must be used day-ahead or will otherwise be released to the day-ahead market-coupling algorithm (*use-it-or-sell-it* principle). It is currently not possible to keep *these* transmission rights for transactions in the intraday market, while for balancing power markets they may be reserved under specific

[36] In this context, a forward period exceeding five years can be considered long-term.
[37] Strictly speaking, the target model does not explicitly reference cross-border forward markets. Still, through explicit long-term transmission rights, it is possible to participate in foreign forward markets.

circumstances.[38] Moreover, bilateral agreements exist to allow for some cross-border intraday trading.

3.3 *Price formation*

A shift towards a market-based evaluation of power is at the very core of this liberalisation process that was started in 1996. In the case of the day-ahead market, there is a uniform, i.e. non-discriminatory, market price for each hour of the day. This price is a result of intersecting all offers and bids. Typically, this price is set by the variable production costs of the marginal power plant, i.e. the last power plant that is needed to satisfy electricity demand. That means all generators receive the same price irrespective of their variable production costs. As a result, generation units with variable production costs below the market price receive a so-called 'infra-marginal rent'. This margin – typically referred to as gross margin – is used to cover *fixed* operation and maintenance (O&M) costs as well as to recover investment costs. Thus availability is implicitly remunerated through infra-marginal rents.

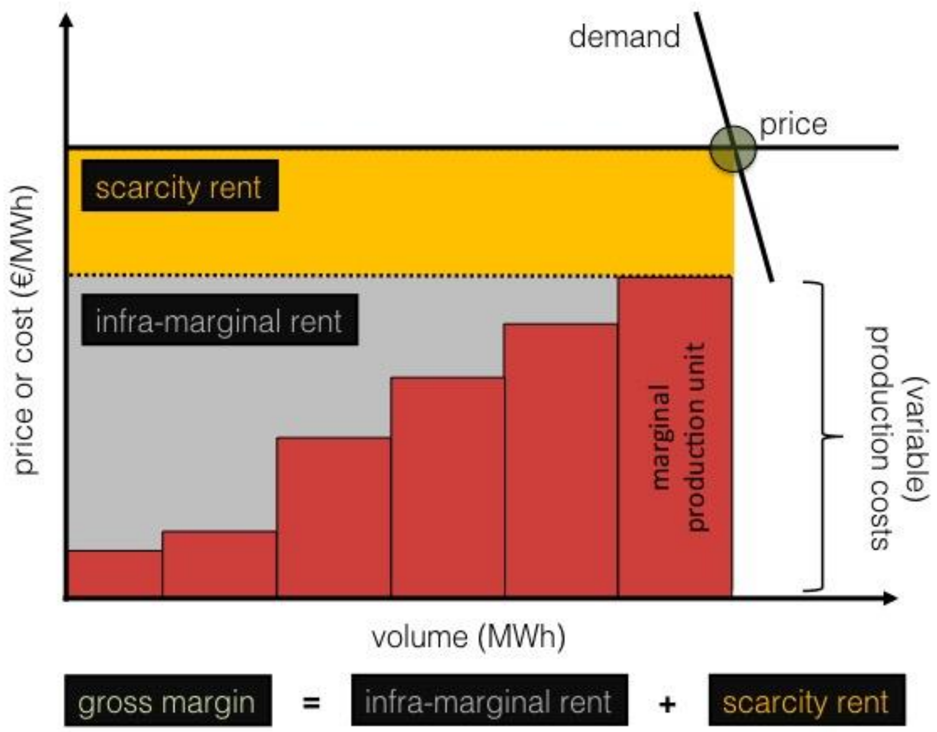
If market prices were always equal to the variable production costs of the marginal plant, this plant would not even be able to cover its *fixed* O&M costs, let alone recover its investment costs. This is why so-called 'scarcity prices' are required to let an energy-only market function properly.[39] Such price increases are expected to occur when supply struggles to meet demand. This can happen when consumption peaks, when production from intermittent renewable sources is low or when there are large, rapid swings in demand or supply. During these hours, the price would rise above variable production costs of the marginal plant and thus offer a so-called 'scarcity rent' to all resources in the market.[40] These additional revenues are needed to fully recover both fixed O&M and investment costs. A simplified cost-production curve is shown in *Figure 7*.

[38] The network code on 'electricity balancing' allows for reserving transmission capacity for balancing markets subject to cost-benefit analysis.

[39] It can be shown that such scarcity prices are needed not just for the marginal production unit but for all units in order to recover fixed and investment costs (see Joskow, 2007). Scarcity prices can only occur if there is no restriction on the bid price. This means generators must be allowed to bid above marginal costs. At the same time, competition authorities must ensure this does not lead to strategic bidding, i.e. exercising market power.

[40] It is important to note that scarcity prices are not binary in a competitive market – that is they do not jump from the marginal cost of the most expensive generator to the maximum price of a power exchange. Instead, the market price is likely to be set by the actual cost to activate voluntary demand-side resources.

Figure 7. Cost-production curve (merit-order) when capacity is scarce



3.4 Investment

An energy-only market attracts investment in new capacity in a number of ways, through either direct or indirect reliance on scarcity prices. Indirect reliance refers to market participants entering into commercial arrangements with each other in order to hedge their exposure to the price and volume risk. In practise, unexpected policy interventions, erroneous demand expectations and long lead times for planning and building new capacity lead to boom and bust cycles, i.e. times of overcapacity alternate with times of scarce capacity. When there is overcapacity, scarcity prices are not going to occur, simply because supply is always well above demand, which signals that there is no need for new capacity.[41] Scarcity prices can also be suppressed, if there is a price cap set too low (see also section 4.2, "Implementing scarcity pricing").

3.5 Low-carbon investments

The ETS is foreseen as the primary instrument to incentivise low-carbon investment. Given the surplus of carbon allowances in the ETS, the incentive to invest in low-carbon is currently limited. There is no price signal for the long-term scarcity of carbon right now.

[41] There are other ways in which scarcity pricing can be suppressed or distorted in energy markets, e.g. through direct public interventions or through system operators (partly) socialising balancing costs.

It is worth noting that at least two-thirds of the capacity, which entered the market in 2000-14, did not have to rely on price signals from the market but was supported by dedicated policies (see Box 2). The design of these policies greatly varies across the EU with a majority of member states granting operating aid, i.e. remunerating the electricity produced.[42] A minority of states has opted for investment aid, i.e. upfront support at the beginning of the project. The performance of policies can be measured in terms of effectiveness and economic efficiency.[43] The first indicator refers to the ability to trigger investment, while the second indicator refers to the ability to provide an adequate support level that allows investors to recover their costs at a reasonable rate of return. Interestingly, there is empirical evidence that overcompensation, i.e. a low economic efficiency, does not necessarily lead to strong market growth, i.e. great effectiveness.

Support schemes featuring long-term contracts (such as a feed-in tariff granted for a duration of 10-20 years) have proven to be effective, because the uncertainty about future revenue streams is low. Considering that the price of the contract is fixed, there is no price risk and only a limited volume risk. The latter is determined by the uncertainty about the *actual* availability of the plant and of natural resources, e.g. wind and sun. This high certainty translates into low financing costs, which can be significant for such investment due to the cost structure of variable renewables such as wind and solar. Since these technologies have close-to-zero variable production costs, they are capital-intensive, i.e. costs mostly arise in the planning and construction phase of a project.

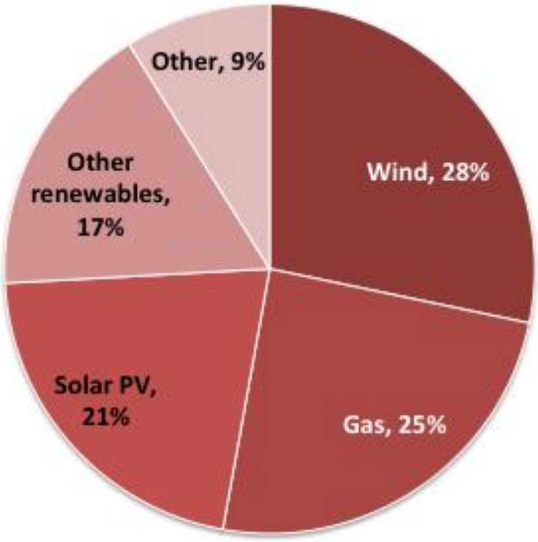
The design of support systems has also drawn criticism, mainly in the following three areas. First, feed-in tariffs have mainly been set administratively and not in a competitive bidding process, which has led to overcompensation in some cases. Second, renewable generators have often not been subject to the same responsibilities as other conventional generators, particularly when it comes to balancing. Thus balancing costs have implicitly been covered by a third party. Third, support systems often lacked a possibility to control the deployment volumes. As a result, total support costs sometimes grew faster than envisaged by policy-makers.

[42] See Held et al. (2014).
[43] See Held et al. (2014b).

Box 2. Investments in power capacity, 2000-14

From 2000 to 2014, over 400 GW of new capacity has been deployed in the EU. Of this, 35% has been gas, 29% has been wind and 21% has been solar photovoltaic. In total, gas and renewables made up for 91% of the new capacity (see *Figure 8*).

Figure 8. New installations in power capacity (EU, 2000-14, total: 412.7 GW)



4 Critical issues and challenges in finding a suitable solution

Based on the findings of the previous chapter, critical issues will be identified, followed by a discussion of challenges to finding a suitable solution.

4.1 *Critical issues*

Wholesale markets

There is currently a disconnection between wholesale prices and the full costs of low-carbon technologies. Consequently, no market-driven investment decisions will be taken based on the current level of wholesale power prices. Yet a technological transformation to a low-carbon power sector will require considerable new investment, some which will be the replacement of existing carbon-intensive capacity with more flexible, less carbon-intensive forms of power generation. It is necessary to understand how this will be done.

There is consensus that renewables will be an important part of this technological transformation.[44] So far, renewable energy investment has mostly *not* been triggered by wholesale price signals based on internal energy market regulation and the ETS. EU member states have primarily relied on dedicated policy instruments to support the deployment of renewables.[45] Apart from a number of inefficient design choices for these support systems – see section 3.5 – many stakeholders and some EU member states consider it cost-effective to finance certain renewable energy technologies under long-term contracts because of the cost structure of wind and solar. These technologies have close-to-zero variable production costs but high upfront investment costs. Consequently, risk has a greater impact on the financing costs of such technologies than it has on coal or gas.

There are two side effects of using dedicated support policies. First, these reduce the demand for electricity generated from conventional sources. Second, there is more fluctuation of demand for electricity from conventional sources, because renewable generation depends to some extent on weather conditions. Decreasing hours of operation of conventional power plants create a need for a different mix of conventional generation technologies, as these do not just differ in their variable production costs but also in their fixed and investment costs. So-called 'base-load' capacity is used to cover the minimum continuous level of electricity demand, as it has relatively low variable but high fixed and investment costs. Consequently, when hours of operation diminish, some base-load would be expected to be replaced with capacity that has lower fixed costs (so-called 'mid-merit' and 'peak-load' capacity).

The business case of peak-load is generally considered challenging, because investment costs have to be recovered from a low number of hours of operation. What's changing with renewables is that (i) more of these units will be needed and (ii) the exact amount required is

[44] According to the EU Energy Roadmap, every decarbonisation scenario will feature a high share of renewables, i.e. at least 64% in 2050, see SEC(2011) 1565 Parts 1 and 2.

[45] The example of nuclear in the UK shows there is a preference to extend this approach to other low-carbon technologies.

subject to greater uncertainty than today due to the weather-dependent availability of renewables. Moreover, in the competition for the remaining market share of mid-merit technologies, the more flexible sources with their higher production costs are currently losing out and the business case for them is becoming more challenging.

This comes at a time when Europe seems to be entering a situation where overall demand for electricity (even before allowing for renewables) is not growing, and in fact may decline, unless other sectors such as heating or transport are electrified. This represents a radical change for the industry, which for over 100 years was used to steady growth.

Retail markets

The different level and composition of retail prices across EU member states shows that – almost 20 years after starting the liberalisation process – the internal energy market remains far from complete. National energy taxes, national grid access tariffs and national levies do not allow for price convergence at the retail level.

Furthermore, the current retail pricing *mechanism* is subject to debate. First, because retail prices include cost components that are not related to electricity supply. Second, because the retail price structure does not fully reflect the system cost structure. This leads to inefficient investment signals (see also section 2.3, "Disincentive to invest in retail storage and demand-response").

4.2 Challenges in finding a suitable solution

Implementing scarcity pricing

Scarcity pricing refers to the concept of prices reflecting not only the cost of producing electricity but also reflecting, in times of scarcity, the value to consumers of being able to consume electricity (see section 3.4). In times of scarce capacity, prices would rise to the level reflecting the cost of other measures to balance the system. The resulting price and volume risks would spur commercial risk management undertakings by market participants and, together with market prices themselves, allow generators to recover their fixed costs.

Three major barriers to implementing scarcity pricing are generally identified: (i) price caps, (ii) market-exit barriers and (iii) a limited exposure of market participants to the risk of scarcity.

Price caps are typically set by regulatory authorities in order to prevent market participants from exercising market power in times of scarcity, since a large share of demand is considered not (to be able) to react to market price signals. Such lack of demand-response is due to technical constraints or retail pricing mechanisms. Generally, dynamic tariffs are required, i.e. retailers offering tariffs to consumers that change fairly frequently, e.g. from day to day, in order to pass on market signals to them. Right now, most small-scale consumers such as households or small enterprises have contracts with flat tariffs that are constant over a relatively long period of time, e.g. one month or even one year. Often, such tariffs are the consequence of a technical constraint. For instance, many consumers are not metered in real time, as this would require interval or smart meters. As a result, today often it is not possible to offer consumers dynamic tariffs.[46] Another challenge is the retail pricing mechanism. Even if dynamic tariffs can be offered technically, a large part of the retail price simply is not dynamic, because retail price components such as taxes and levies are static, i.e. not moving over time. This represents a disincentive to shift consumption or invest in storage.

Price caps may also be introduced on purely political grounds, i.e. as a price control instrument. Power exchanges might also define a price cap merely for technical reasons. For instance, the price cap of the French or German market is not a legal cap, i.e. it is not imposed by a regulator.[47]

Whether a price cap represents an actual barrier to implementing scarcity pricing depends on the level at which such price caps are set. If the level is above the price that makes consumers indifferent to being able to consume and not being able to consume, the cap is not a relevant barrier to implementing scarcity pricing. The challenge lies in determining such a price level *ex ante*. In fact, an array of prices would have to be defined, as different consumers have different 'indifference prices'.

For scarcity pricing to work properly, it is required that the decision when to build or decommission capacity is left to market participants and is not a result of an intervention by regulators or governments. For instance, in some EU member states regulators need to approve the closure (and even mothballing) of power plants[48] – even if these are no longer profitable or required to maintain resource adequacy. These market-exit restrictions are usually justified on the grounds of these power plants being needed for system stability or security reasons. Effectively, such a market-exit regulation imposes an *implicit* cap on wholesale market prices, because it maintains overcapacity. The situation is aggravated by the fact that there are policies pushing additional capacity into an already-saturated market, e.g. support systems for renewables or more recently for nuclear. Consequently, one would expect that market participants would take a corresponding amount of capacity *offline*. While this is happening to a certain extent, it is happening at a slower pace than needed to restore market equilibrium.

[46] It is worth noting that much can be achieved already before a large-scale roll-out of smart meters. A positive example here is France. In order to reduce peak consumption (especially in winter), the concept *event pricing* is used, i.e. prices being higher during a limited number of days per year when demand is expected to be high. Customers are notified via email or text message one day in advance.

[47] It currently amounts to €3,000 per MWh. In 2014, the maximum price observed in the market was roughly 3% of the price cap. It is worth noting that the German day-ahead market price has never reached this cap since the power exchange was introduced, because the volume of offers was always well above the volume of bids. In France, the cap was reached in four consecutive hours on 19 October 2009.

[48] This is the case for Spain and Germany, for instance.

Finally, market participants are currently not fully exposed to the risk of scarcity. There is a disconnection between energy market prices and the concurrent value of scarcity in balancing services. For instance, costs of imbalance are partly socialised instead of being allocated to its originator. This puts a limit on the scarcity revenues of generators and reduces the incentive to fully hedge against the risk of scarcity. Also, some measures taken at times of system stress, such as the activation of voluntary demand-side measures arranged ahead of time, may have costs higher than the marginal generator but may not be factored into the formation of market prices, implicitly capping scarcity revenues for other resources.[49] Yet, it is important to note that some of these measures have to be taken at *local* level by system operators to resolve *local* grid congestion. Consequently, only resources that contributed to resolving the congestion should be rewarded.

Capacity mechanisms

Capacity mechanisms offer an explicit remuneration for being available or delivering energy in times of system stress. For generators, these parallel streams of revenue allow the recovery of that portion of their fixed costs that is not recoverable in energy and balancing markets. Moreover, the dependency on uncertain scarcity revenues is reduced.

In the EU and elsewhere, this is not a theoretical debate anymore, as capacity mechanisms have been implemented or are in the process of being implemented in several EU member states, including France, Germany,[50] Italy, Belgium and the UK. They also have a long history in South America and in the US, where several states rely on both energy and capacity markets. These experiences can provide helpful insights also for the EU debate.

[49] One example is the German ordinance on interruptible load (so-called "Lastabschaltverordnung"). The availability price for this service was fixed to €2,500 per megawatt per month.

[50] Strictly speaking, there is currently no capacity mechanism in place in Germany. Yet there is a so-called 'grid reserve' ('Netzreserve') to make sure that TSOs have access to sufficient 'redispatch' capacity. Redispatch is a measure to resolve internal grid congestion. Since it provides a capacity-based revenue stream for generators, it acts as a kind of *de facto* capacity mechanism.

The design of capacity mechanisms varies across EU member states. Nordic countries and Belgium have opted to complement their energy-only market with a strategic reserve, i.e. a generator of last resort. In this case, the grid operator contracts a certain amount of capacity in a competitive bidding process. This capacity is withheld from the market and is only activated when an *extreme* scarcity event occurs, e.g. triggered by a price.[1] Germany has set up a 'light' strategic reserve (so-called 'Netzreserve'). Power plants, which generators plan to take offline but which are considered relevant for system stability by grid operators, are placed into this reserve.[1] The mechanism is considered temporary; it will expire by the end of 2017. There is currently a debate on a suitable follow-up mechanism with a preference to implement a strategic reserve. Belgium is currently reviewing its approach in a public consultation launched by the Belgian regulator CREG.

Effectively, a strategic reserve introduces a capacity-based revenue stream for those power plants that are placed into the reserve. It is therefore not intended to attract investments.

In general, the current approaches can be distinguished by the following design questions:

- What is the product being contracted? (e.g. availability or energy delivered in times of system stress)
- Who is contracting the product and deciding how much of it to buy? (e.g. a grid operator or retailers)
- How long is the forward period, and how long is the commitment period?

Product-wise, France is contracting availability, while the UK and Italy are contracting energy delivery in times of system stress. Most US mechanisms also contract availability.

The UK and Italy prefer a centralised approach, where a centralised authority sets a generation adequacy target. This authority is also the counterparty. France is imposing an obligation on retailers to contract enough firm capacity or demand-response to meet the consumption profile of their customer portfolio. In the US and South America, where capacity markets have been adopted, there has been a preference for centralised approaches, e.g. New England, Pennsylvania-New Jersey-Maryland Interconnection (PJM), Colombia.

Commitment periods are rather short in most US mechanisms, i.e. around one year. In the UK, 15-year agreements are possible for new capacity and three-year agreements are possible for refurbished capacity. In the Italian model, a commitment period of three years is foreseen.

Dealing with overcapacity

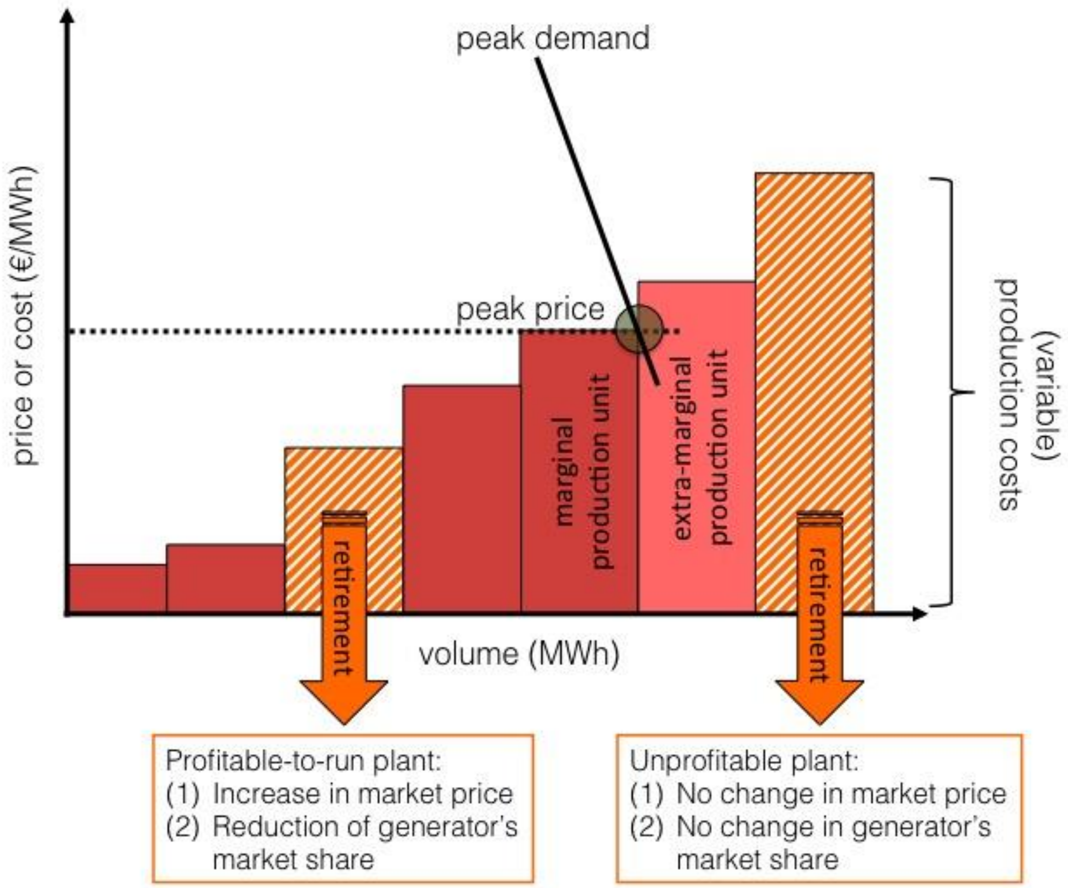
Some stakeholders also argue that it is mostly the 'wrong' type of capacity, which has recently been taken offline or mothballed. Announced closures mostly affect capacity, which is not profitable to run[51] anyway. This is typically the case for gas-fired units. Therefore, the

[51] In this context, "profitable to run" means a power plant is able to recover its variable production costs from selling electricity but not necessarily its (reversible) fixed costs.

closures have no impact on wholesale prices. Instead, closing down coal-fired units would have such an impact on prices.

Although the slow pace of restoring market equilibrium is partly related to existing market-exit barriers, it is also related to the fact that first-movers are at a disadvantage. Taking capacity offline, which is currently profitable to run, will increase wholesale prices overall and therefore increase profits for all generators. Yet the net effect for the generator decommissioning a power plant can be negative, since his market share might decrease. This is illustrated in *Figure 9*.

Figure 9. Retirement of existing capacity – impact on prices and market share



Some argue that this development is inconsistent with long-term decarbonisation objectives, because it is mostly gas-fired stations that are being retired or mothballed, which may be needed in the long run for a transition to a low-carbon power sector. In the context of market design, it is important to point out that restoring market equilibrium does not just require reducing overcapacity. The right mix of power plant technologies is needed, as these do not just differ in their variable production costs but also in their fixed and investment costs.

Peak-load technologies are used to cover rare peaks in demand. Therefore, their utilisation is low. Consequently, these technologies need to have low fixed costs but can have high variable costs. Open-cycle gas turbines are typically used for this task. Base-load technologies such as lignite have higher fixed costs but lower variable costs. Consequently, they are used to cover the minimum continuous level of electricity demand. Mid-merit technologies are used to follow daily and weekly swings in demand and tend to have fixed and operating costs that fall in the middle between base-load and peaking plants.

In order for markets to send efficient price signals, it is essential that there is a balance amongst peak-load, mid-merit and base-load technologies.[52]

[52] see IEA (2014)

5 Inventory of solutions

When it comes to suitable solutions, opinions vary among stakeholders. In general, one can distinguish between recommendations shared among all Task Force members, and non-consensual options backed by smaller groups within the Task Force.

5.1 Shared recommendations

5.1.1 Fully implement the EU target model

Among stakeholders there is general consensus that fully implementing the EU target model is a no-regret action. Significant progress has been achieved when it comes to connecting national day-ahead markets (see chapter 3). Similar progress will be needed for intraday and balancing markets.

This will require, as a necessary first step, *standardising products* as well as harmonising *gate closure times* and *price caps* in order to facilitate cross-border trade. At a later stage, the various national intraday and balancing markets would be fully coupled. This process is currently ongoing and not as advanced as the coupling of day-ahead markets. In a joint initiative, power exchanges and TSOs from 12 countries plan to create a joint integrated intraday cross-border market by the end of July 2017.[53]

5.1.2 Do not prescribe the creation of separate flexibility markets; adapt existing short-term markets instead

In general, stakeholders seem to be confident that there is no need for a policy intervention that would prescribe the creation of a separate flexibility market, e.g. a market in which the ability to react to sudden load changes would be remunerated separately. Flexibility could be valued through prices provided by already existing short-term markets (intraday market, balancing power market). In principle, this is possible in the existing framework. Flexibility has a low value right now, because of overcapacity, undue price caps and the structure of balancing prices. Often, these prices do not reflect the real cost of balancing the system.

Hence, it would not be a matter of introducing *ad hoc* flexibility markets. Instead, existing short-term markets should be implemented properly and developed further. For instance, the participation of the demand-side and renewables could be facilitated, as long as these comply with the standards for the secure operation of the network. Options are:

- Ensure all generators are subject to the same balancing obligations. This will increase the liquidity and efficiency of balancing power markets.
- Ensure balancing prices reflect the costs of balancing the system at that time. This will provide an incentive to invest in flexible resources on both the demand and the supply sides.
- Shorten the commitment period in balancing power markets, e.g. from a monthly/weekly to a daily commitment period provided that system constraints

[53] See XBID (2015).

can be met. This allows for participation of intermittent and demand-side resources based on their expected day-ahead availability.

- Organise separate tenders for positive and negative balancing power.[54] This allows for easier participation of the demand side and renewables. For the demand side it is typically easier to provide positive power, i.e. reducing demand, than negative power, i.e. increasing demand. Conversely, it is typically easier for renewables to provide negative balancing power, i.e. curtailing production, than positive, i.e. ramping up production.
- Move gate-closure times[55] closer to real time in order to allow renewable energy generators to make use of their updated production forecast, while taking into account system constraints.

It is important to note that by introducing *fixed* payments for capacity, the ability of short-term energy markets to adequately price flexibility *can be* impinged. Unless this issue is addressed, this can lead to the need to differentiate the value of different types of capacity in capacity remuneration mechanisms or to introduce a specific flexibility mechanism.

5.1.3 Remove barriers to scarcity pricing

The expression of scarcity pricing might or might not be made sufficient to attract investment in new capacity. However, it is reasonable to remove barriers to scarcity pricing as much as possible in any case. This requires removing unnecessary price distortions from energy and balancing markets (see section 5.1.2), strengthening the role of demand-response in wholesale markets and removing undue market-exit barriers. It is sometimes argued that politicians will not be willing to remove price caps in order to prevent unpopular price spikes. In this context, it is important to note that 12 neighbouring EU member states have recently announced they will not introduce any legal price caps in their markets.[56]

Strengthening the role of demand-response in wholesale markets is important so as to enable a rational expression of scarcity value and, ultimately, to better estimate the required level of firm generation capacity – or in other words, to avoid both excessive price volatility and overestimating the need for generation capacity.

Market-exit barriers, where not justified by system adequacy issues, prolong the current overcapacity situation artificially, suppressing wholesale prices and keeping net support costs for renewables at a higher level than necessary.

Finally, it is important to note that generators must be *allowed* to bid above variable production costs for scarcity pricing to work properly. This raises the question of how to distinguish between strategic bidding and the recovery of fixed costs. In practice, abusive

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[54] Grid operators use balancing power to keep the balance between production and consumption close to real time. Positive balancing power can be provided by generation units ramping up or consumers decreasing their load. The opposite is the case for negative balancing power.

[55] This refers to the time until orders and offers can be submitted to a power exchange.

[56] See BMWi (2015).

behaviour can be avoided by ensuring that the market is highly liquid, by having a sufficiently price-elastic demand-side in the market and by active monitoring of competition authorities.

5.1.4 Ensure a clear and cost-effective policy framework for renewables

The share of renewables in the power sector will continue to grow significantly in the short, medium and long terms on the basis of legally binding national targets for 2020 and according to the decisions of the European Council from 23-24 October 2014, which has agreed on a new set of targets for 2030. For renewables, the target is to reach a share of 27% in final energy consumption by 2030. If the power sector will continue to contribute more than other sectors to reaching the overall target, the share of renewables in final electricity consumption can be expected to be above 45% by 2030.

Stakeholders agree that it is crucial to have sufficient certainty on how much and when new capacity is entering the market through dedicated policy instruments. In the past, this has not always been the case, as these dedicated support mechanisms lacked the possibility of 'volume control.' The Guidelines on energy and environmental aid 2014-20 foresee such volume control, as they prescribe the use of competitive bidding processes for larger installations. This is also expected to increase the overall cost-effectiveness, as the support level would be a result of an auction and no longer set administratively. Furthermore, the Guidelines require that renewable generators are subject to balancing obligations.

The European Commission should therefore ensure that national support systems are adapted to the Guidelines and set framework guidelines for the period beyond 2020 as soon as possible.

5.2 Non-consensual options

Several Task Force members are of the opinion that the above-mentioned measures could not be sufficient to ensure investment in renewables and other low-carbon technologies as well as ensure that enough capacity stays online. Thus the following options are non-consensual.

5.2.1 Capacity markets

As outlined earlier, some Task Force members state there is a need to implement capacity markets to allow for the recovery of that portion of their fixed costs that is not recoverable in energy and balancing markets, thus ensuring security of supply.

The decision of whether to supplement an energy market with a capacity mechanism is a regulatory design choice and ultimately an implementation challenge.

One key design element of capacity mechanisms that was debated at length in this Task Force is the duration of the commitment period. The underlying question is how to allocate risks between private investors and the public. In the current framework, the market risk, i.e. the price and volume risk, is taken by the investor. Transferring this risk to the public by granting long-term contracts would reduce the uncertainty on revenue streams and therefore lower the financing costs of an investment. This risk transfer has to be weighed against potential costs for overestimating the demand for new capacity, which would then have to be borne by the public and not the investor. It is worth noting that in the context of renewables, many EU member states consider long-term contracts cost-effective, as long as there is *ex ante* competition on their level of support.

National capacity mechanisms are a consequence of security of supply being a predominantly *national* responsibility. At the same time, a European capacity mechanism is likely to ensure a higher level of competition and therefore be more cost-effective.

Resource adequacy if assessed cross-border, e.g. regionally instead of nationally, should help avoid over-contracting capacity nationally, when idle capacity exists in neighbouring countries. Regarding this specific point, there seems to be growing consensus considering that 12 neighbouring EU member states have recently announced they are working towards 'a joint regional generation adequacy assessment'.[57]

While cross-border participation in national systems would be desired for the sake of better functioning of the internal energy market and EU-wide efficiency, to implement it in practice might be difficult. For example, it would require that capacity that is contracted cross-border is indeed available and able to deliver its service at any time. This might require intergovernmental agreements between member states or similar agreements, possibly under EU law. Suggestions for explicit participation of cross-border capacity exist[58] and should be explored, for example in regional initiatives serving as a stepping stone towards an integrated EU market. The implementation of regional energy policy cooperation initiatives is a priority of both the Energy Union and the "2030 framework for climate and energy policies".[59]

5.2.2 Market-exit signals

Another issue, which has been discussed at length in this report and elsewhere, is overcapacity. Provided that market-exit barriers are removed, there is consensus that excess capacity will be retired sooner or later, because it will become economically unviable to keep it online, thus resolving the problem of overcapacity.

Some stakeholders argue that the pace of reducing overcapacity is currently insufficient to restore market equilibrium and will not be, as long as there is no mechanism to incentivise the decommissioning of existing capacity made redundant by the publicly subsidised addition of new, low-carbon capacity.

The ETS could theoretically provide such a price signal. Yet, in its current state, the ETS is not providing any significant decommissioning signal for carbon-intensive power plants. In

[57] Ibid.
[58] See Mastropietro et al. (2015).
[59] See also de Jong & Egenhofer (2014) as well as CEPS work on regional energy policy cooperation, including in south-east Europe: www.ceps.eu/content/Regionalisation-of-EU-energy-policies.

this situation, EU member states have been exploring ways to gradually push redundant plants out of the market. Options are carbon price floors, carbon taxes or emissions performance standards. A swift adoption and implementation of the Market Stability Reserve proposed for the EU ETS is another mechanism for contributing to this goal. Moreover, in some EU member states, the Large Combustion Plant Directive and the Industrial Emissions Directive will lead to a retirement of existing capacity.

5.2.3 Cross-border transmission capacity allocation

There was no consensus regarding the question of how to allocate cross-border transmission capacity efficiently between long-term, day-ahead, intraday and balancing markets. Currently, all commercially transmission capacity is allocated to the *day-ahead market* under the use-it-or-sell-it principle. That means that market participants can reserve transmission capacity explicitly but are obliged to use it for day-ahead contracts or release it to the day-ahead market auction where it will be allocated implicitly. It is therefore not possible to reserve transmission capacity for cross-border activities in intraday, while for balancing power markets it may be reserved under specific circumstances.[60] Moreover, bilateral agreements exist to allow for some cross-border intraday trading.

Some stakeholders argue that it would be more efficient to have the possibility to explicitly reserve transmission capacity for the intraday market, especially considering that the importance of this market is expected to increase with a growing share of intermittent renewables. This is because their forecast quality increases while moving closer to the time of delivery. Other stakeholders point out that system constraints might not generally allow for such an allocation rule.

5.3 Conclusions

Many of these solutions are not mutually exclusive but can be combined. For instance, it is possible to implement a basic capacity market that provides relatively short forward commitments, e.g. one year, in combination with concerted efforts to improve price formation in energy and balancing markets.

It will, however, be important to ensure that market rules are implemented properly and consistently. Market-driven investment requires a predictable and credible long-term framework. The challenge will be to instil confidence that these rules are in fact stable and that market outcomes, especially in terms of wholesale prices and security of supply levels, will not eventually trigger a public intervention. In order to achieve this, it is important that – irrespective of which approach will be chosen – this framework is based on evidence and enjoys the support of the broadest possible stakeholder group.

[60] The network code on 'electricity balancing' allows for reserving transmission capacity for balancing markets subject to cost-benefit analysis.

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Annex I: Glossary

Term	Description
Balancing market	Marketplace ensuring that deviations between forecast and actual production/consumption are balanced close to real-time
Capacity mechanism	Explicit remuneration for availability (see also energy market)
Day-ahead market	Marketplace for a commodity to be delivered the following day
Dynamic tariff	End-consumer price reflecting the dynamics of prices at power exchanges (see also static tariff)
Energy market	Market where the price is based on energy produced / consumed
Energy-only market	Energy market without a capacity mechanism
EU target model	Current blueprint for the EU internal energy market
Flexibility markets	Potential marketplace to trade flexibility products (e.g. ability to swiftly ramp up production)
Forward market	Marketplace where trading is not very close to real-time (see also short-term markets)
Gate-closure time	Time until bids can be submitted to an auction
Generation adequacy (also: system/resource adequacy)	Ability of a power system to meet consumers' requirements at almost all times
Intra-day markets	Marketplace for a commodity to be delivered close to real-time
Market coupling	Initiative connecting national marketplaces in order to form a single market
Market Stability Reserve	Supply-side mechanism for the EU ETS
Negative balancing power (see also positive balancing power)	Demand-side offering to increase consumption or supply-side offering to decrease production
Price cap	Upper price limit set by the regulator ("legal") or a power exchange ("technical")
Positive balancing power (see also negative balancing power)	Demand-side offering to decrease consumption or supply-side offering to increase production
Scarcity pricing	Concept of prices reflecting not only the cost of producing electricity but also reflecting, in times of scarcity, the value to consumers of being able to consume electricity
Short-term market	Marketplace where trading is close to real-time, e.g. day-ahead, intraday, balancing (see also forward markets)
Static tariff	End-consumer price not reflecting the dynamics of prices at power exchanges (see also dynamic tariff)

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