The Power Market Pentagon

A Pragmatic Power Market Design for Europe's Energy Transition

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A Pragmatic Power Market Design for
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Layout: UKEX GRAPHIC, Ettlingen
Cover image: pranodhm - Fotolia

096/04-I-2016/EN
Publication: April 2016

Please cite as:
Agora Energiewende (2016): *The Power Market Pentagon: A Pragmatic Power Market Design for Europe's Energy Transition.*

www.agora-energiewende.de

Preface

Dear Reader,

as consequence of Europe's climate and energy agenda, the European Union will generate some 50 percent of its electricity from renewables by 2030. By 2050, the EU's power system will have to be completely carbon-free. Solar photovoltaics and wind power – driven by significant cost reductions – will almost certainly contribute the biggest share of the zero-carbon technologies. Given the specific characteristics of wind power and photovoltaics (intermittent generation, high capital costs, very low variable costs), they will fundamentally change both market operations and the market design framework.

Decarbonisation rests on continuous investments in these technologies. Usually it is expected that the energy market will deliver these investments, in combination with the emissions trading system. But is this view, based on simple textbook economics, enough to enable the required investments under real world conditions? In this paper, we argue that this rather theoretical view to power market design is not the way forward. Instead, a more pragmatic approach is needed, that takes into account the complex practical, political, and economic challenges of the transition towards a carbon-free power system. Thus, we propose to think of the future European market design as a Power Market Pentagon.

I hope you find this paper inspiring and enjoy the read! Comments are very welcome.

Yours sincerely,

Patrick Graichen,
Executive Director of Agora Energiewende

Key Findings at a Glance

1. **The European power system will be based on wind power, solar PV and flexibility.** The existing climate targets for 2030 imply a renewables share of some 50 percent in the electricity mix, with wind and PV contributing some 30 percent. The reason is simple: they are by far the cheapest zero-carbon power technologies. Thus, continuous investments in these technologies are required for a cost-efficient transition; so are continuous efforts to make the power system more flexible at the supply and demand side.

2. **Making the Energy-Only Market more flexible and repairing the EU Emissions Trading Scheme are prerequisites for a successful power market design.** A more flexible energy-only market and a stable carbon price will however not be enough to manage the required transition to a power system with high shares of wind and solar PV. Additional instruments are needed.

3. **A pragmatic market design approach consists of five elements: Energy-only market, emissions trading, smart retirement measures, stable revenues for renewables, and measures to safeguard system adequacy.** Together, they form the Power Market Pentagon; all of them are required for a functioning market design. Their interplay ensures that despite legacy investments in high-carbon and inflexible technologies, fundamental uncertainties about market dynamics, and CO_2 prices well below the social cost of carbon, the transition to a reliable, decarbonised power system occurs cost-efficiently.

4. **The Power Market Pentagon is a holistic approach to the power system transformation.** When designing the different elements, policy makers need to consider repercussions with the other dimensions of the power system. For example, introducing capacity remunerations without actively retiring high-carbon, inflexible power plants will restrain meeting CO_2 reduction targets. Or, reforming the ETS could trigger a fuel switch from coal to gas, but cannot replace the need for revenue stabilisation for renewables.

Content

Introduction

At the global climate summit in Paris in December 2015, Europe committed to the global target of limiting climate change to "well below 2 °C above pre-industrial levels" as well as to "pursue efforts to limit the temperature increase to 1.5 °C above pre-industrial levels."[1]

To adhere to the Paris Agreement, Europe must stay within the upper range of the decarbonisation pathways set forth in the EU's 2050 roadmap. Specifically, it must reduce overall greenhouse gas emissions by 95 percent by 2050 below 1990 levels.[2] This will not be possible without complete decarbonisation of the power sector.

Investment choices taken in the years from 2015-2030 will be critical for determining whether the EU's power system will transition smoothly towards full decarbonisation in 2050. A smooth transition requires a stable investment framework. A stable investment framework, in turn, would create an economically virtuous cycle, generating new jobs, economic growth and enhanced economic competitiveness.

There is a clear danger that Europe's energy transition will be held back by legacy investment choices, path dependencies and textbook economic views that idealise the transformative power of markets. Together, these risks could create costly stop-and-go cycles, lock-in effects and much higher costs for the energy transition than is necessary. Globally, it would mean that Europe would forego the economic benefits of an energy revolution it has helped to create, leaving the early mover benefits to the US, China and some rapidly emerging economies, to the detriment of Europe's competitiveness and its industrial base.

The key place for minimising these risks is the EU-level regulatory framework, which shapes investment choices in the power sector. Currently, this framework relies excessively on simple "textbook economics", failing to create the certainty needed by real-life investors while also delivering too little, too late.

In this paper, we contrast the simple textbook approaches currently in place – specifically, those consisting of an Energy-Only Market (EOM) and Emissions Trading System (ETS) only – with a pragmatic and solution-oriented approach that we call the Power Market Pentagon. Our approach seeks to maximise the value of the EOM and the ETS in the transition period, but expands on it with three elements:

- → (1) measures to actively remove inflexible high-carbon capacity from the system;
- → (2) measures to generate stable revenue streams for the needed investments into new renewable energy capacities (which will provide the backbone of the EU's future, fully decarbonised power mix); and
- → (3) measures to safeguard system adequacy.

We explain how the different parts of the Power Market Pentagon interact and why this approach will attract the investments needed in the 2015-2030 period – while also keeping costs low and ensuring continued power system reliability.

1 Paris Agreement, Article 2.1 a).

2 The 80-95 percent range was set against the previous objective of keeping climate change below 2 °C. See "A Roadmap for moving to a competitive low carbon economy in 2050", COM (2011) 112 final of 8 March 2011.

Part I Europe is on the road to a power system based on wind, solar and flexibility

In December 2015 at the Paris Climate Conference, the EU was part of the "high ambition coalition" that successfully pushed for the adoption of a global, legally binding target for stabilising climate change "well below 2 °C above pre-industrial levels" as well as for "efforts to limit the temperature increase to 1.5 °C above pre-industrial levels."[3]

The EU's negotiating position was based on an agreement reached by EU leaders in October 2014 regarding new EU climate and energy targets for 2030[4]:

- → To reduce EU domestic greenhouse gas emissions by at least 40 percent;
- → To reach a share of at least 27 percent of renewable energy in gross energy consumption;
- → To enhance energy efficiency by at least 27 percent.

Since the Paris Agreement was reached, there has been much discussion concerning the possible adoption of more ambitious EU targets.[5] This discussion is motivated by two factors: first, recent data released by the European Environment Agency[6] show that Europe will reach its climate and energy targets set for 2020[7] well before this date. Second, the 40 percent greenhouse gas target set for 2030 keeps Europe's decarbonisation pathway at the lower end of the 80-95 percent range for greenhouse gas reduction by 2050.[8] However, in view of the robust and binding global target reached in Paris and because industrialised countries must continue to lead in reducing global emissions, the EU would have to aim for the upper bound of its 2050 target range.

This means the power sector will have to be fully decarbonised by 2050 at the latest.[9] The remaining carbon budget in 2050 will be needed for sectors that do not possess the technical potential for cost-efficient decarbonisation, such as agricultural or heavy industry, where there are technical limits to emission reductions. In order to achieve this goal, about half of the effort needs to be met by 2030, implying large investments in zero-carbon technologies within the next 15 years.

In this section we first explain why wind and photovoltaics will shape Europe's future power system and how increased flexibility in power supply and demand will ensure cost-effective integration. We then set out the main challenges in 2015-2030, when transitioning to higher shares of renewable power in the grid.

3 See Paris Agreement, Article 2.1 a).

4 European Council (23 and 24 October 2014), Conclusions on 2030 Climate and Energy Policy Framework, Doc SN 79/14.

5 Note the Resolution of the European Parliament of 15 December 2015 on the Energy Union. In its resolution the Parliament "Acknowledges the European Council's weak 2030 targets for climate and energy, namely to reduce greenhouse gas emissions by 40 percent, to increase the share of renewables in the European energy mix to 27 percent and to increase energy efficiency by 27 percent; recalls that Parliament has repeatedly called for binding 2030 climate and energy targets of at least a 40 percent domestic reduction in GHG emissions, at least 30 percent for renewables and 40 percent for energy efficiency, to be implemented by means of individual national targets."

6 EEA (2015), Trends and projections in Europe. Tracking progress towards Europe's climate and energy targets, EEA Report No 4/2015.

7 20 percent reduction in domestic greenhouse gas emissions, 20 percent share in renewable energy, 20 percent increase in energy efficiency.

8 EC (2011): A Roadmap for moving to a competitive low carbon economy in 2050. COM (2011) 112final.

9 EC (2011): Impact Assessment Energy Roadmap 2050, SEC(2011) 1565/2.

Already in 2030, some 50 percent of electricity will be generated by renewable sources.

The EU 2030 target to generate at least 27 percent of its energy from renewables translates according to the EU Commission into a 45 to 53 percent share of renewable electricity in the power sector.[10] The renewables share in the electricity sector is higher because cheaper decarbonisation options (namely, wind power and solar PV) exist in the power sector compared to the heat and transport sector. The share of renewable electricity could be even higher if Europe raises its overall ambition for 2030 in line with the Paris global climate agreement.

Ramping up to a 50 percent or higher annual average share of electricity from renewable sources presents a formidable challenge. Today, the RES-e share in Europe stands at some 26 percent.[11] This means the next 15 years will see roughly a doubling of the share of RES-e in power systems throughout Europe.

According to current trends, photovoltaic installations and onshore wind turbines will by far make up the largest share of newly installed renewable energy capacity.[12] Put simply, these two technologies have won in the race for bringing down technology costs. Furthermore, significant further cost-reductions are expected, particularly for PV (see below).

10 See the Commission Impact Assessment on a policy framework for climate and energy in the period from 2020-2030 (COM SWD (2014) 15 final of 22.1.2014) for scenarios in line with a 40 percent GHG emission reduction. Note that the required investment in renewables is a function of the energy efficiency targets, see RAP (2015): Efficiency First: Key points for the Energy Union Communication.

11 European Commission, 2015. Renewable energy progress report, COM (2015) 293 final.

12 Since 2000, 443 GW of new power capacity was installed in Europe, 58 percent of which was renewables, mostly wind and solar (European Wind Association, 2016: Wind in power, 2015 statistics). Looking at 2050, the scenarios included in the EU's Energy Roadmap 2050 show a share of wind power and solar PV up to 72 percent in the electricity mix (EC, 2011: Impact Assessment Energy Roadmap 2050, SEC(2011) 1565/2). This trend holds not only in Europe, but worldwide (see, e.g., IRENA Renewable Energy Capacity Statistics 2015).

Wind turbines and PV panels produce electricity when the wind blows and the sun shines. As such, they are volatile sources of power generation that cannot simply replace current baseload capacity on a megawatt by megawatt basis. Transitioning to much higher shares of volatile RES-e in the system will thus have system-wide repercussions: large, centralised generation capacities will make space for more and more decentralised zero-carbon technologies. This, in turn, will have consequences for planned investment into network infrastructure at the level of both transmission and distribution. Overall, power systems will need to become more flexible both in terms of providing supply and meeting demand. In the following, we highlight some important aspects of this transition.

Over the next 10-15 years, large parts of Europe's power plant fleet need to be replaced or retrofitted.

Most of Europe's power plant fleet was built before the liberalisation and cross-border integration of European power markets. Today, more than 60 percent of Europe's coal power plants are older than 30 years.[13] Assuming an expected lifespan of 40 years for gas plants, 40-50 years for hard coal plants and 50 years for lignite and nuclear plants, a significant share of the European fleet will reach the end of its lifetime in the coming 15 years. Well before the expiration of such plants – that is, particularly over the next decade – utility companies will have to decide whether to retrofit such plants, to replace them with low or zero-carbon generation capacities, or whether to invest in the smart and efficient use of smaller capacity plants. This process is also driven by EU legislation. European air and water quality standards,[14] for example, require the retrofitting or closure of older thermal plants. Furthermore, nuclear plants have to comply with more stringent safety standards adopted in the wake of Fukushima.

13 Platts (2016)

14 For example, those codified in the Industrial Emissions Directive (IED), the Mercury Directive, or the Water Framework Directive.

Full decarbonisation of the power system requires shifting to generation technologies that do not emit greenhouse gases.

Considering the lifespan of investments into generation capacity and the objective of achieving full decarbonisation of the power sector by 2050, every investment made today in fossil fuel-based plants has a high risk of becoming a stranded asset.[15] Thus, forward-looking investors have the choice between the three currently available zero-carbon technologies, i.e. renewable energy, nuclear power or fossil fuels with carbon capture and storage (CCS).

Wind and solar PV are already the cheapest zero-carbon energy technologies; further cost reductions are expected in the future

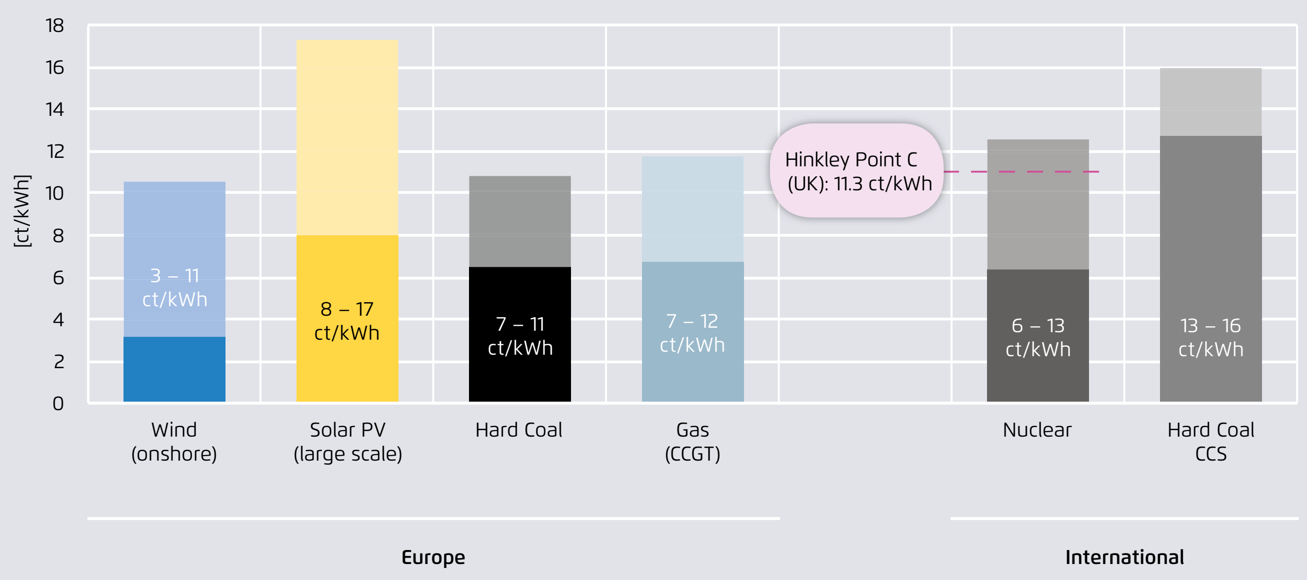
From a pure technology-cost perspective, renewables – especially onshore wind and solar PV – already today outcompete the other zero-carbon technologies. The levelised cost of electricity (LCOE) for these two technologies has fallen dramatically: onshore wind has seen a cost decrease of over 50 percent since 1990 and new turbines produce electricity throughout Europe for as low as 3.15 ct/kWh up to11 ct/kWh (see Figure 1)[16]. Furthermore, the wind turbines of today are 15 times more powerful than 20 years ago (see Figure 2). Costs for solar PV have fallen even quicker – by up to 80 percent since 2008 (see Figure 3). As of today, the LCOE for solar PV has reached 8 ct/kWh at the best sites in Europe.[17]

15 Carbon Tacker (2015): The $2 trillion stranded assets danger zone: How fossil fuel firms risk destroying investor returns.

16 IRENA (2015): Renewable Power Generation Costs in 2014; Agora Energiewende (2015): Understanding the Energiewende. FAQ on the ongoing transition of the German power system; Bundesnetzagentur (2016): Bericht Pilotausschreibungen zur Ermittlung der Förderhöhe für Photovoltaik-Freiflächenanlagen.

17 WEC (2014); Fraunhofer ISI (2013), IRENA (2014)

Range* of levelised cost of electricity (LCOE) 2015 — Figure 1



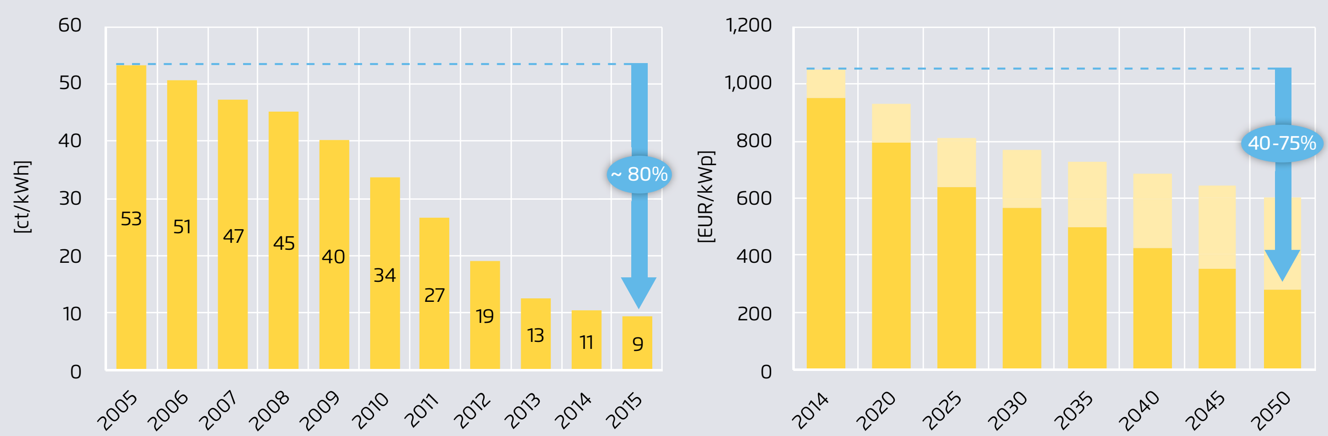
Agora Energiewende (2015), IRENA (2015), BNetzA (2016)

* based on varying utilisation, CO_2-price and investment cost

Size development of wind turbines 1990 - 2015 Figure 2

IEA (2013)

Average PV feed-in tariff for new installations 2005 - 2015 (left) and expected cost degression for large-scale PV systems 2014 – 2050 (right) Figure 3



ZSW et. al (2014), own calculations

Fraunhofer ISE (2015)

Future projections indicate a continuation of these downward trends. The LCOE for solar PV is expected to fall to 4-6 ct/kWh by 2025, reaching 2-4 ct/kWh by 2050 (see Figure 3),[18] while the range for onshore wind in 2030 is 2-7 ct/kWh, strongly influenced by current WACC spreads.[19] Offshore wind is still relatively expensive, but could see significant cost reductions according to some analysts if further investments into this innovative technology advance the technology learning curve and enable the industry to further rationalise and up-scale its activities.[20]

Most other renewable technologies are still significantly more expensive or constrained by available potential. The latter is especially the case for hydroelectric power, which constitutes the biggest share of RES in the current system. Regarding bioenergy plants, both costs and the available resource potential significantly constrain wider deployment. Site restrictions (e.g. terrain conditions, environmental protection) or competition for land use (e.g. for agricultural purposes) are particularly relevant. The situation with geothermal energy is similar: limited potential and high costs set clear limitations on significantly increasing the share of this technology in the power sector. Other technologies such as wave power or osmosis are still in the developmental stage. It remains to be seen whether they will ever play a meaningful role. It should be noted, of course, that stark differences exist throughout Europe in terms of technical and economic potentials. However, this does not change the overall picture: namely, that wind and solar PV will be the two dominating renewable energy technologies.

18 Fraunhofer ISE (2015): Current and Future Cost of Photovoltaics. Long-term Scenarios for Market Development, System Prices and LCOE of Utility-Scale PV Systems. Study on behalf of Agora Energiewende.

19 IRENA (2015): Renewable Power Generation Costs in 2014; NREL (2015): 2015 Standard Scenarios Annual Report; Diacore (2016): Assessing Renewables Policy in the EU.

20 While the LCOE of offshore wind in the UK is around 17 ct/kWh, it could fall to 10.7 ct/kWh in 2020 according to Crowne Estate 2012 and Prognos/Fichtner 2013

Wind onshore and solar PV are the cheapest decarbonisation options; and integrations costs are well defined and rather low

Comparing the levelised cost of electricity (LCOE) of wind power and solar PV with conventional generation technologies, one finds that these two renewable sources can already produce electricity at the same cost level as new coal and gas plants (see Figure 1) – and significantly lower than the other zero-carbon technologies nuclear and CCS.

From a system perspective that considers the costs of integrating variable wind and PV technologies into the power system, the picture does not change substantially.

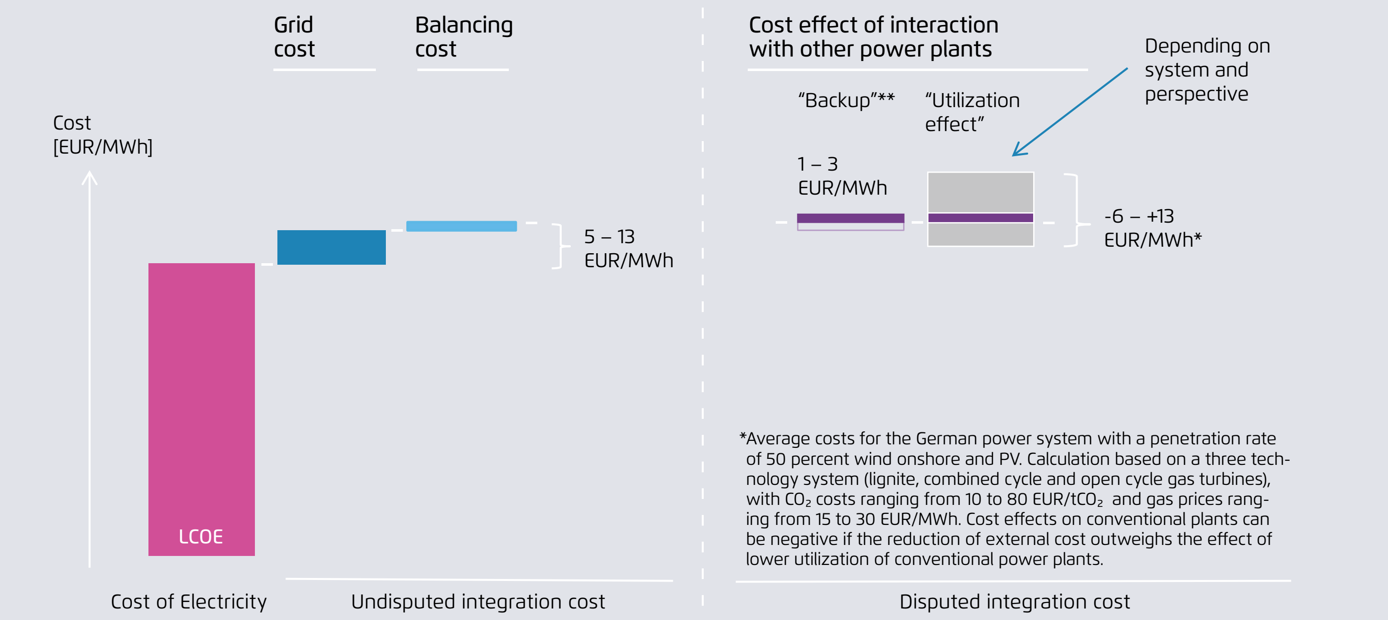
Three components are typically discussed under the term "integration costs" of wind and solar energy: grid costs, balancing costs and cost effects on conventional power plants (so-called "utilization effect").[21] The calculation of these costs varies tremendously depending on the specific power system and methodologies applied. Moreover, opinions diverge concerning how to attribute certain costs and benefits, not only to wind and solar energy but to the system as a whole.

Integration costs for grids and balancing are well defined and rather low. Certain costs for building electricity grids and balancing can be clearly classified without much discussion as costs that arise from the addition of new renewable energy. In the literature, these costs are often estimated at +5 to +13 EUR/MWh, even with high shares of renewables.

However, experts disagree on whether the "utilization effect" can (and should) be considered as integration costs, as it is difficult to quantify and new plants always modify the utilization rate of existing plants. When new solar and wind plants are added to a power system, they reduce the utilization of the existing power plants, and thus their revenues.

21 For further details see IEA (2014): The Power of Transformation; Agora Energiewende (2015): The Integration Cost of Wind and Solar Power. An Overview of the Debate on the Effects of Adding Wind and Solar Photovoltaic into Power Systems.

Components of the "integration costs" discussion — Figure 4



Own illustration **included in „utilization effect". In reality, quantifying the cost of backup alone, without considering the change of utilization of the entire power plant fleet, is misleading and does not capture key points of the controversies. The back-up calculation presented here is only illustrative. It is assumed that the addition of 300 TWh of wind and solar PV in Germany (~50% of electricity demand) requires 20 GW more capacity compared to an alternative addition (300 TWh) of new base load capacity. The calculation assumes this back-up would be provided by new open cycle gas turbines.

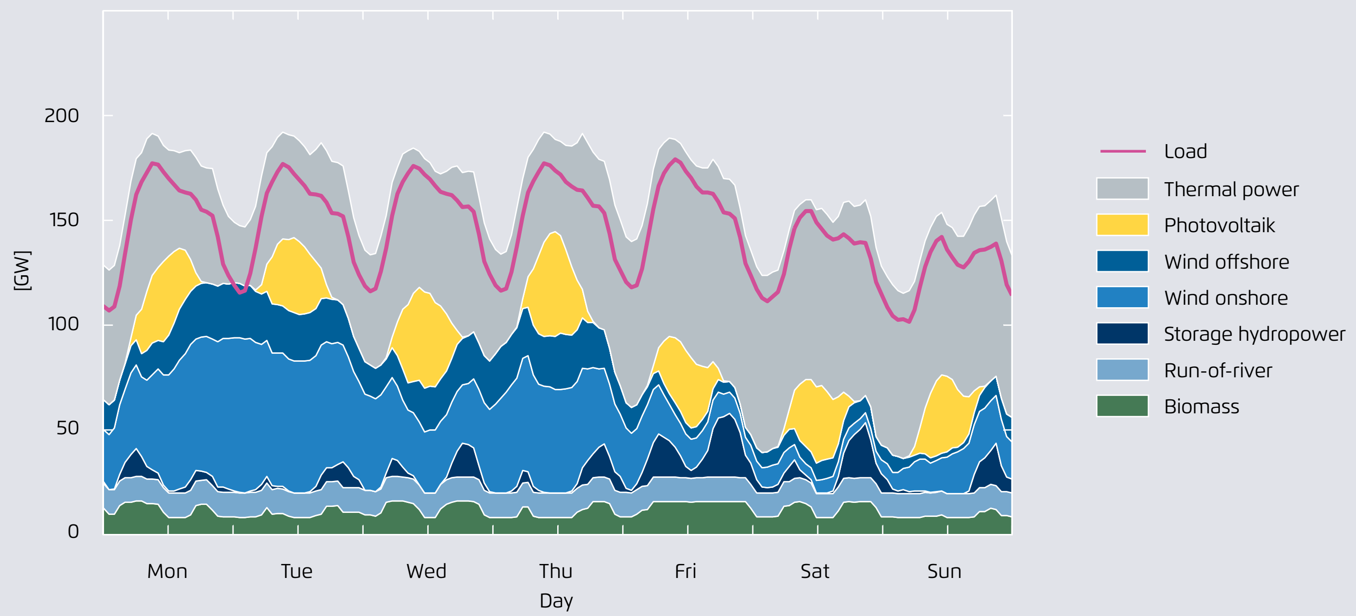
Thus, in most cases, the cost for "backup" power increases. Calculations of these effects range between -6 and +13 EUR/MWh in the case of Germany at a penetration of 50 percent wind and PV, depending especially on the CO_2 cost. Despite the debate about integration costs, the comparison of the total power system costs of different scenarios is a more appropriate approach to analyse the question "What are the implications of choosing path A or path B?"[22]

22 A greenfield power system, for example, consisting of 50 percent newly built wind and solar combined with 50 percent newly built gas-fired power plants would yield total power generation costs of around 70 to 80 EUR/MWh (including integration costs). These costs are 21 percent lower than a system with the same emission performance but consisting of 50 percent nuclear generation and 50 percent gas-fired generation (Prognos (2014): Comparing the Cost of Low-Carbon Technologies: What is the Cheapest Option? Study on behalf of Agora Energiewende).

Wind power and solar PV produce electricity dependent on weather conditions and daylight. As electricity generation from wind power and solar PV is variable, this requires the rest of the system to react flexibly to changing feed-in from these technologies.

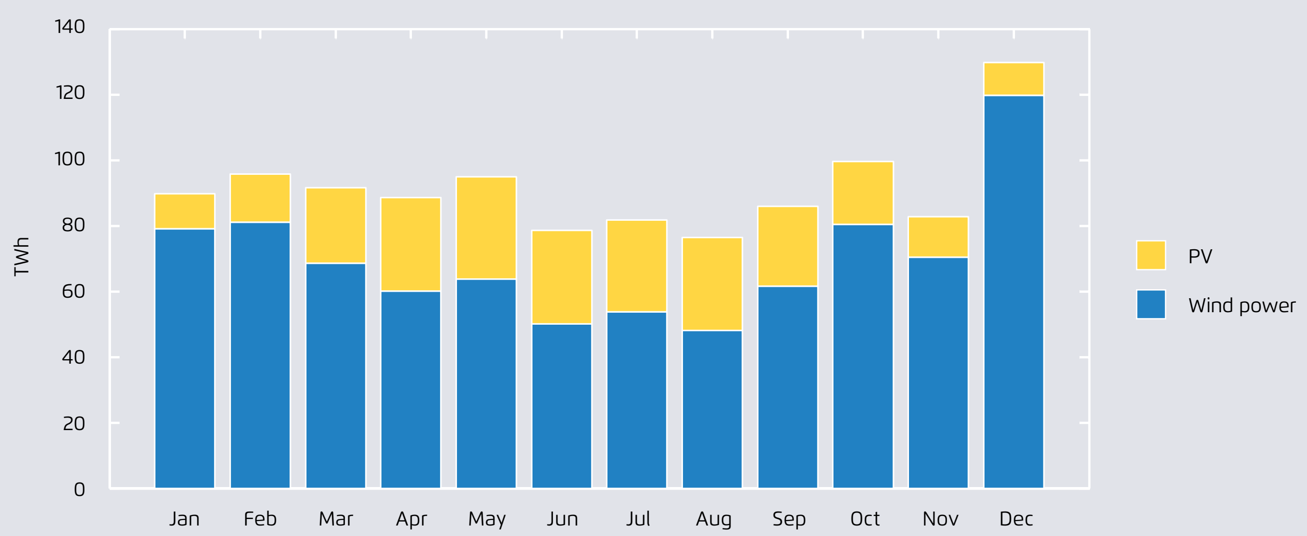
The electrical system will have to respond more flexibly as the share of wind and PV increases. Figure 5 illustrates this need for flexibility. In the case presented, the wind dies down in tandem with a drop in the generation of solar power. As a result, controllable power plants have to cover a major portion of the demand within a few hours. In a worst case scenario, demand might increase at the very same time – for example, if a large part of the population comes home at sunset and turns on electrical appliances, television sets and lights. In these hours, conventional power plants and imports will have to cover almost the entire load, irrespective of the amount of installed wind and PV capacities – and irrespective of the fact that in the preceding hours wind and PV might covered almost all of power demand. Thus, the fu-

Electricity generation* and consumption* in the CWE region in a week in late summer 2030 (calendar week 32) Figure 5



Fraunhofer IWES (2015) * Modelling based on 2011 weather and load data

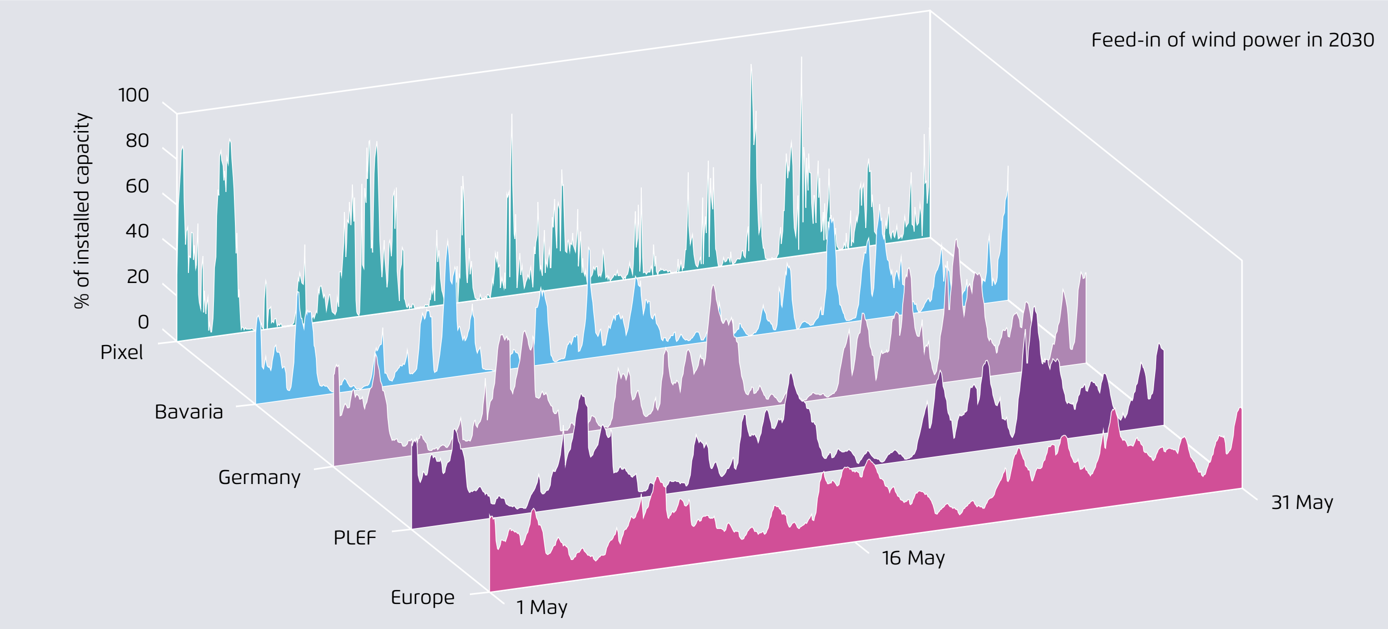
Monthly wind power and PV generation in Europe in 2030 Figure 6



Fraunhofer IWES (2015)

Time series of onshore wind power generation in a simulation for May 2030 at different levels of aggregation (as a percentage of the installed capacity at the specific aggregation level). Note that one pixel is equivalent to an area of 2.8 x 2.8 km.

Figure 7



Fraunhofer IWES (2015)

ture power plant mix will contain less baseload capacities and relatively more mid-merit and peak load capacities that quickly adjust their production. In essence, conventional power plants will have to ramp up and down more frequently, operate often at partial loads, and be turned on and off with greater regularity.

A geographically widespread expansion of wind and solar PV will help to reduce the burden of increasing flexibility. Wind and solar PV complement each other as their generation patterns are different. While solar radiation is strongest in summer and most sunshine occurs during mid-day, the wind can blow at any time, and it usually blows stronger in the winter in Europe (see Figure 6).

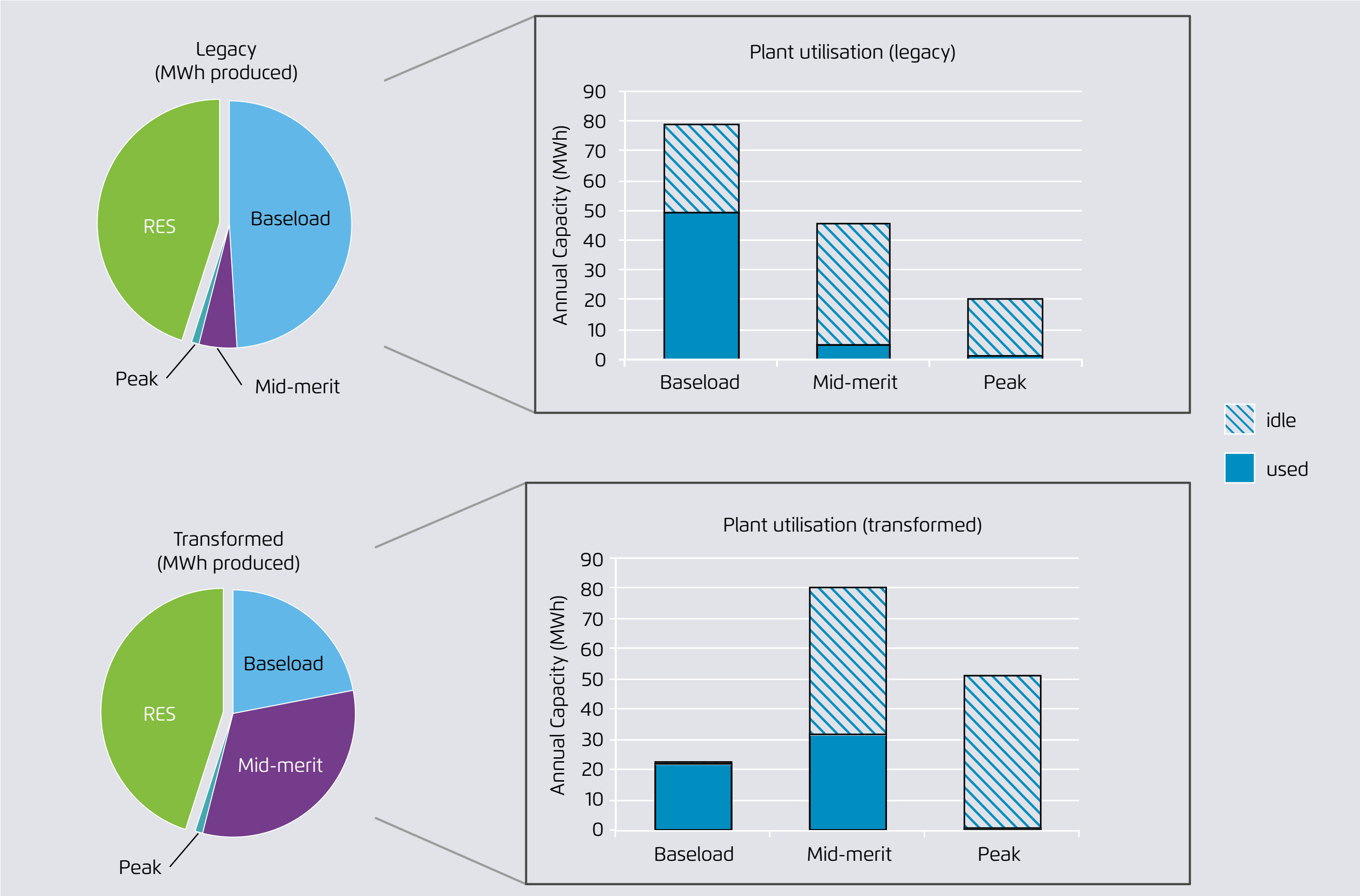
This asynchronous input can be further exploited through the geographic distribution of wind and solar PV plants yielding a smoother total output across Europe (see Figure 7).

The more flexible a power system, the lower the total system costs when wind and solar PV shares are high.

A recent study by the International Energy Agency highlights the economic benefits of a power system in which the power generation mix shifts in response to the growing role of variable renewables by *increasing* the share of *flexible resources* and by *decreasing* the share of *inflexible resources*.[23] Under two scenarios, each with a 45 percent share of variable renewable electricity, and the same demand and reliability standards, the *transformed scenario* shows a utilisation rate of baseload plants at 96 percent, of mid-merit plants at 39 percent and of peak plants at 4 percent. This contrasts with the *legacy scenario* where the incumbent mix remains essentially unchanged during the transition and most of the non-renewable energy production comes from inflexible baseload plants. In this scenario, the utilisation rate of baseload plants is at 62 percent, of mid-merit plants

23 IEA (2014): The Power of Transformation.

Impact of thermal plant mix on investment and plant utilisation rates — Figure 8



RAP (2014) adapted from IEA (2014)

at 11 percent and of peak plants at 2 percent. These results imply quite different levels of investment: the *transformed scenario* delivers the same amount of energy at the same reliability but with over 40 percent less investment required (see Figure 8).[24]

Put differently: unless an increase in the share of variable renewable power is accompanied by a system shift to a qualitatively different, more flexible capacity mix, society will be economically worse off. From a policy-making perspective it is thus economically sound to simultaneously flexibilise the power system and deploying increasing shares of variable renewables.

Later on, we address economic and regulatory aspects of this "flexibility challenge"[25]; here, we focus on technical aspects.

24 Assuming 3,500 EUR/kW investment costs for baseload, 1,300 EUR/kW for mid-merit and 350 EUR/kW for peaking plants. Source: RAP (2014): Power Market Operations and System Reliability: A contribution to the market design debate in the Pentalateral Energy Forum. Study on behalf of Agora Energiewende.

25 See below Parts II and III.

All power systems possess a broad range of flexibility options.

The need for flexibility can be met through various supply and demand flexibility options, through increased storage capacities, and through improved grids.

From a current perspective, the cheapest option is to optimise the **grid**. Expanding the grid over larger geographical areas has several positive effects. Electricity produced by wind and PV can be better balanced as weather conditions vary over larger areas (thus smoothing regional imbalance). In a similar manner, cumulated annual peak load is lower than the sum of national peak loads, as demand patterns are different from country to country and region to region. Finally, dispatchable capacity can be shared throughout Europe. Hence, less capacity for peak times needs to be provided.[26]

In addition to grid expansion, from today's perspective the most important flexibility options are as follows:

→ Dispatchable power plants should be operated to supplement generation from wind power and solar PV plants, thus flexibly providing the remaining difference between power demand and renewables feed-in.

→ Today, this flexibility option is often not exercised at plants generating both electricity and heat (combined heat and power, or CHP) or at older nuclear, coal or biomass facilities that are usually run in a baseload mode. In principle, however, more flexible operation poses few technical problems and the costs of modifying a plant for more flexible operation are relatively low. For example, CHP plants merely require that heat may be fed into storage facilities.

→ **Conventional thermal power plants** offer large potential for improved flexibility. With technical and organisational adaptations, the minimum output rate can be reduced, load gradients increased, and start-up times shortened. The more flexible operation of retrofitted and new plants is also important for reducing the minimum generation level of thermal power plants (i.e. the "must-run" level).[27]

→ **Demand response** is another cost-effective flexibility option with great potential. This is especially the case for electricity demand by industrial companies, as a considerable proportion of this demand comes from large plants with centrally controlled processes. Technically, it would be quite possible in many cases to shift demand several hours by adapting production processes and, if applicable, installing storage capacity for intermediate products as well as for hot, cold or compressed air. Additional large and cost effective opportunities for flexibility are available in the retail sector. Large refrigeration or heating facilities, for example, can be upgraded and centrally controlled to store heat or cold for a short time. The potential seems significant, as figures from the US suggest: The demand response potential is in the range of 10 percent of the peak load.[28]

→ **Storing** electricity is another option, although one needs to take a closer look at the different technologies. In the current system, pumped hydro plants constitute the most important storage technology. Some countries, e.g. in Scandinavia and in the Alps, already have significant storage capacities. However, for Europe as a whole, the potential for further expanding pumped hydro is rather limited, as plants usually have strong impacts on the environment and often stand in conflict with environmental protection goals or the preferences of local populations. New storage technologies, on the other hand, such as batteries in various application, including electric vehicles, adiabatic compressed air storage, and power to-gas systems are from today's perspective still expensive, yet

26 Fraunhofer IWES (2015): The European Power System in 2030: Flexibility Challenges and Integration Benefits. An Analysis with a Focus on the Pentalateral Energy Forum Region. Analysis on behalf of Agora Energiewende.

27 For more details see Agora (2012), p. 12.

28 Synapse / RAP (2013): Demand Response as a Power System Source.

promising technologies.[29] It might be that new storage technologies enter the picture through the wide-scale deployment of electric vehicles. In any event, electric vehicles will enhance the flexibility of the power system over the mid term

- Finally, curtailment of electricity feed-in from wind and solar PV can be an economically viable flexibility option as well. Usually, one would think that curtailing wind and solar PV means throwing away electricity that was already paid for. After all, both technologies have high investment costs, but marginal costs of almost zero. Still, from an economic perspective it does not make sense to enlarge the grid such that it allows for the transmission of every single kilowatt-hour at times of very high generation that occur only during a few hours per year. Limited curtailment of renewable generation in the range of 1-3 percent would reduce grid costs up to 25 percent.[30]

All of the flexibility options mentioned above are technically mature and available for implementation. The increasing need for flexibility in the system potentially provides a business opportunity for those able to offer flexibility. However, this necessitates an adequate price signal and the stable expectation that flexibility services will be economically rewarded. This issue, which is addressed below, has a direct link to the debate on improving the market design of the energy-only market, to the smart retirement of inflexible baseload capacity, and to the ETS price (see Part III).

Sector-coupling – that is, combining the power, heating and transportation sectors – allows a huge flexibility potential to be tapped

Instead of throwing away electricity from wind or solar plants when the potential generation is higher than demand, it would naturally be better to use it for other purposes. An integrated system would provide many opportunities in this regard. The heating sector has a large potential for additional electrification, especially as demand for heat in most European countries is higher than that for power, and heat can be stored relatively easy. Heat can be produced by using electrical heating rods in warm water accumulators – one kWh of electricity generates one kWh of heat – or by using heat pumps, where one kWh of electricity generates about four kWh of heat. CHP plants already today constitute a bridge between the power and the heating sector. As most CHP plants are still operated in accordance with demand, it would be relatively easy to upgrade them to respond to demand for power instead. In the future, dual-mode systems that produce heat either with fossil fuels or with electricity will be widely used.

With a view to the transportation sector, electric vehicles are a well-known example of a technology that bridges the transportation and power sectors. Experts see a large potential for electric vehicles to be integrated into the power sector – although a crucial factor is the scope of electric vehicle adoption. The key challenge will be to ensure the large-scale charging of vehicles when there is ample wind and solar PV generation. In the medium to long run, technologies like power-to-gas, power-to-heat and power-to-transport will integrate the three sectors.

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29 Agora Energiewende (2014): Electricity Storage in the German Energy Transition.

30 Agora Energiewende (2015): The Integration Cost of Wind and Solar Power. An Overview of the Debate on the Effects of Adding Wind and Solar Photovoltaic into Power Systems; ECF (2011): Roadmap 2050.

Part II Why strengthening the Energy-Only Market and the ETS is not enough for a successful EU energy transition

Proponents of a harmonised approach to EU climate and energy policy argue that the European energy transition should be based on two major elements: a strengthened Energy-Only Market (EOM) and a strengthened EU Emissions Trading scheme (ETS). It is argued that these two instruments offer the most cost-effective route for reliably transitioning to a low-carbon energy system. Furthermore, additional instruments distort the effective function of markets and should be phased out as soon as possible.

In this section we first discuss the theoretical basis for such views. We then show why these views, which are informed by idealised simple textbook economics[31], are myopic. We argue that reliance on this approach has a very high risk of derailing a cost-effective decarbonisation pathway, which would have severe negative repercussions for Europe's industrial and technology leadership as well as negative impacts on jobs, growth and competitiveness.

The simple textbook economics of the EOM and ETS

Ample literature exists about the functioning of energy-only based power markets and the proper design of emission trading schemes.[32] However, at least in the EU, the combination of an EOM with the ETS has not been effective thus far in stimulating investment into a diversified, zero-carbon power system of the future.[33] To understand the reasons for these shortcomings it seems useful to first lay out the theory underpinning such claims.

Claim 1: If left undistorted, energy-only markets will provide sufficient revenues and incentives for new investment in all types of power generation and demand response technologies

The theoretical conclusion that EOMs provide sufficient revenues for new investments only holds true under certain conditions and assumptions. First, the demand side has to be price-elastic, i.e. power consumers must reduce their consumption when prices on the power market increase. Specifically, a price-elastic demand curve facilitates market clearing (the process of matching supply and demand) when supply is saturated, yielding so-called scarcity prices (see Figure 9). Consumers with a lower willingness-to-pay compared to the market clearing price will postpone or reduce electricity consumption in these hours, allowing involuntary load shedding (brownouts, rolling blackouts) to be avoided. In turn, prices in these few hours reach rather high levels, thus facilitating total cost recovery for all technologies. In addition to price-elastic demand, the conditions of perfect foresight and perfect competition also have to be met for an EOM to deliver efficient outcomes.[34] If these conditions are met, boom & bust cycles (repeated periods of over- and under-investment) can be avoided.

In the theoretical case, investments in so-called peaking plants are critical. This is because such plants operate for few hours only, at times when consumption is high and renewables production is low. Peaking plants require high power prices (so-called scarcity prices) during their (few) operating

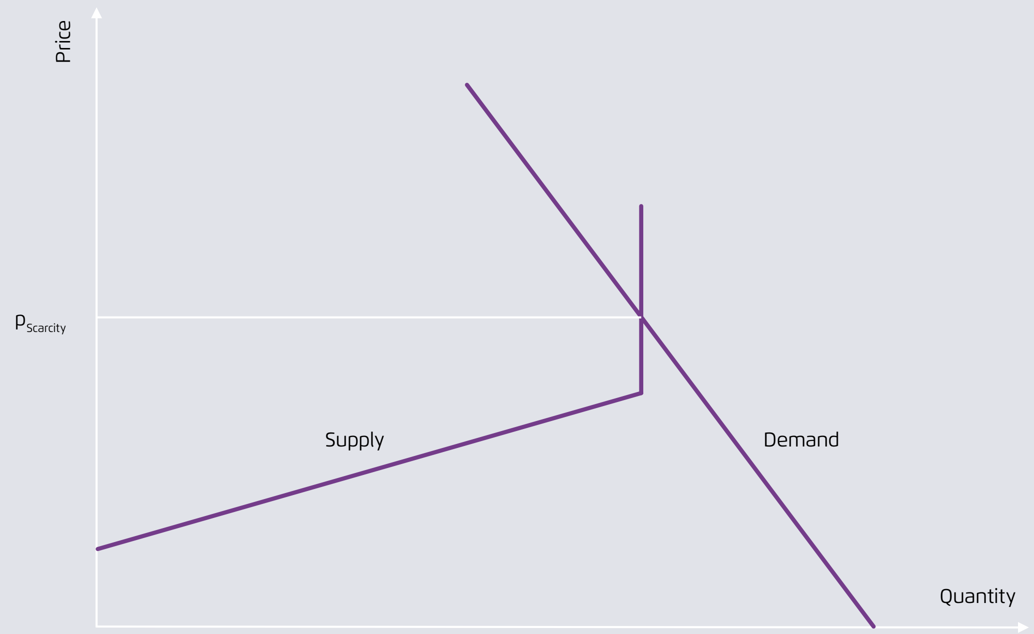
31 Important assumptions of these views are perfect foresight, price-elastic demand and perfect competition as well as the complete internalisation of external cost of carbon emissions.

32 See e.g.: Caramanis, M.C. (1982): Investment decisions and long-term planning under electricity spot pricing. IEEE Transactions on Power Apparatus and Systems 101(12). Crew, M., Fernando, C., Kleindorfer, P. (1995): A theory of peak load pricing: A survey. Journal of Regulatory Economics 8.

33 Most recent figures from BNEF show declining investments into renewable energies only in Europe, and in part strong growth elsewhere in the world (BNEF (2016): Clean Energy Investment: Q4 2015 Factpack.

34 De Vries, L.J. (2003): The instability of competitive energy-only electricity markets.

Scarcity pricing in theoretical EOM environments facilitates cost-recovery of all power plants — Figure 9



Own illustration

hours to enable total cost recovery (including initial investments).

In the future, power will be primarily produced by renewable and low-carbon generation assets. Regardless of the specific technology mix, it will pose an additional challenge because renewables, specifically wind and PV, have relatively high investment costs and relatively low or even zero marginal costs. They are typically in operation when wholesale power prices are low, and they only benefit from high prices to a limited extent. Thus, they are more vulnerable than conventional capacity to stochastic scarcity prices.

In theory, undistorted power markets should ensure total cost recovery for renewable technologies, low-carbon residual load serving technologies and for demand-side response, provided the ETS sets a sufficiently high price on carbon emissions that reflects the deep emission cuts needed.

Claim 2: Emissions trading schemes can incentivise the cost-effective decarbonisation of the power system by setting a binding and declining cap on emissions.

According to textbook theory, the EOM will also steer investments to low- and zero-carbon options, provided the previously externalized costs of carbon emissions are internalized.[35] The amount of this extra cost reflects the "socially responsible" level of carbon emissions that may be emitted by economic sectors that fall under the emissions trading scheme. Ideally, this cap is consistent with long-term emission reductions required to meet long-term climate change targets.

The emissions cap triggers a shortage of emission allowances, which results in a price for emission certificates, in

35 This price can result from an Emissions Trading Scheme or a Carbon Tax. In the following, we solely refer to an ETS. Note that the theory puts a carbon price on all sectors.

turn incentivising abatement measures (which come at a cost; see Figure 10). The certificate price will push the market to favour low-carbon over high-carbon technologies and, theoretically, facilitate a cost-efficient reduction of CO_2 emissions, since investments will happen where marginal abatement costs for reducing a given amount of emissions are lowest.

The certificate price will steer the dispatch of existing resources, favouring the increased use of low-carbon plants while incentivising investment in new low-carbon technologies as well as the closure of high-carbon assets. In effect, the ETS should enable fuel switching from high-carbon to low-carbon conventional assets and from carbon assets to carbon-free renewables.

Similarly to the EOM, the theoretical ETS case relies on certainty for market actors: They must have confidence in the stability of the regulatory framework and that the emissions cap will progressively and reliably be reduced.

The shortcomings of real world EOM and ETS

Recent figures on global renewable energy investment show declining investment levels in Europe, but increasing investment everywhere else.[36] This fact alone should encourage us to take an honest look at the merits and shortcomings of the EOM and ETS as tools for achieving decarbonisation in Europe.

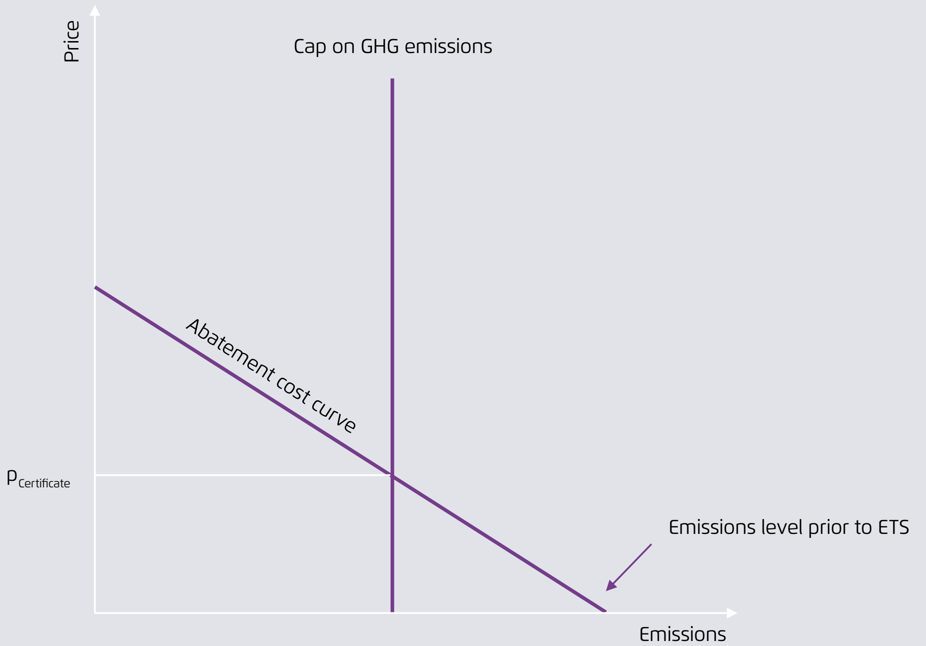
In our view, relying on solutions derived from simple textbook economics will almost certainly cause decarbonisation efforts to fall short. There are at least six reasons for this:

- → The path dependency of legacy investments;
- → Uncertainties about future market developments that market participants are unable to address;
- → The fact that politicians do not want to be seen as potentially responsible for the increasing risk of outages in power systems under stress during the transition;

36 BNEF (2016): Clean Energy Investment: Q4 2015 Factpack

A binding cap on emissions unfolds emission abatement measures. The cost of the “marginal abatement”, required to meet the cap sets the certificate price in an ETS

Figure 10



Own illustration

- → Renewables are likely to cannibalise their own market revenues with rising shares of renewable power in the mix;
- → The EU ETS is to remain oversupplied until the end of the 2030s unless seriously repaired; and
- → Sufficiently high prices for ETS allowances that would incentivize needed investments into zero-carbon technologies seem unacceptable to large parts of industry and thus to politicians.

In the following we address each of these factors in more detail.

Path dependency: The power of existing assets and interests

Markets are social constructs. In real life, they reflect the imperfections and path dependencies of past choices.[37] The historical development of the energy mix in member states is one specific path dependency that constrains action in European climate and energy policy. Past energy system choices were taken without climate policy objectives in mind.[38] Furthermore, power markets throughout the EU have only been partially liberalised and integrated.[39] As a result, the current power system in most parts of Europe is characterised by an over-supply of generating capacity and high shares of inflexible baseload capacity. Both aspects present a major challenge to a market-driven energy transition.

As explained,[40] unless an increase in the share of renewable power is accompanied by a transition to a *qualitatively different*, *much more flexible capacity mix*, the general public will be economically worse off.

This characterises precisely the situation in Europe today, where wholesale power prices do not reward any investments in new capacity, where a large part of the existing fleet is losing money, and where merit-order based dispatch allows cheap coal-fired baseload plants to gradually push more flexible mid-merit and peak-capacity out of the market, hindering both the transition to a more flexible resource portfolio and the decarbonisation of the power system. *At this point in time, the wholesale power market in Europe is working against and not in support of the more flexible mix of capacities needed for a cost-effective energy transition.*

As we have shown elsewhere, currently discussed reforms to wholesale power markets in Europe (e.g. shorter intraday trading intervals, better market access of demand side resources) are unlikely to change this situation.[41] This is simply because there is an abundance of old coal-fired power plants able to undercut more flexible and lower-carbon gas power plants for years to come. Worse, given political realities, incumbent generators – driven by short-term economic necessities – have been quite effective in convincing national politicians that their business woes signal an upcoming shortage in generating capacities, rather than a welcome reduction in over-capacity. A growing number of Member States are reacting by putting in place capacity markets, or more precisely "capacity remuneration mechanisms", which risk locking in inflexible, high-carbon assets.[42] Such interventions have direct costs to electricity consumers or taxpayers. Unless carefully designed, they also have further indirect costs if they artificially prolong the life-time of inflexible capacities in the system, making the overall energy transition more expensive.

37 See the seminal work by North (1990): Institutions, institutional change and economic performance, CUP

38 E.g., Coal was critical to the industrial revolution in Germany, the UK, and others.

39 ACER/CEER (2015): Annual Report on the Results of Monitoring the Internal Electricity and Natural Gas Markets in 2014.

40 See Part I.

41 This argument is developed in more detail in Agora / RAP (2015): The Market Design Initiative and Path Dependency: Smart retirement of old, high-carbon, inflexible capacity as a prerequisite for a successful market design

42 See also the Commission Staff Working Document on Generation Adequacy in the internal electricity market – guidance on public interventions, on the risk of capacity remuneration schemes postponing the exit of inefficient generation capacity from the market (COM SWD(2013) 438 final).

Uncertainty, power market risks and investments

The theoretical logic of EOM and ETS driven investments neglects one important characteristic of real-life markets: Uncertainty. A certain level of uncertainty is simply a given in every market and not negative. However, depending on the nature of the uncertainty it can be a hindrance in markets that are supposed to help meet political targets – as it is the case in the energy and carbon markets in Europe. Uncertainty translates into risk insofar as the economic impact of uncertain events can be calculated. Risk management is a basic economic activity. From the perspective of market participants there are risks that can be hedged against *within* the existing market framework and others that cannot be hedged against (e.g. future changes to market rules) or only at prohibitively high cost.

For conventional technologies, uncertainties and risks related to wholesale market prices are of key importance. Regarding investment, the stochastic nature of scarcity events is arguably the most critical source of risk.

The fact that scarcity events are stochastic (occurring occasionally when demand is high and, at the same time, little feed-in from variable renewables occurs) implies that the total cost of an investment in conventional capacity may not be fully recovered during the operational lifetime of the plant if the number of actual scarcity events (and accordingly high prices) is smaller than expected.

The risk of only partial cost recovery becomes higher the smaller the expected operational hours of the investment option are (investments in so-called peaking plants would be typical examples). What is more, once an investment decision has been taken, depending on the technology, several years can pass until it goes operational, and market conditions might have changed in the meantime. Investors in mid-merit and peaking plants thus apply "top-ups" – i.e. risk premiums – to their investment assessment valuation, which implies that enough capacity might not be built if expected wholesale prices are lower than resulting total investment costs. Financing costs also rise with the level of uncertainty.

Fuel price developments and the evolution of future ETS certificate prices constitute another source of risk, yet they are already an intrinsic part of the power price risk, as fossil-fuel power plants typically set prices price in the wholesale market and the operators of conventional plants can thus hedge themselves through risk management activities (e.g. buying derivatives of the inputs [primary energy and CO_2 allowance forward contracts] and selling derivatives of the output [electricity forward contracts]).

Whereas hedging instruments (physical or financial contracts such as futures, forwards, or options) to reduce market risks are available, these instruments cannot fully alleviate all uncertainties. For example, the available long-term markets for hedging are typically not complete.[43] Accordingly, a simple theoretical energy-only market setting cannot always ensure enough capacity, as market risk cannot be optimally allocated among market participants. Less than optimal capacities cause (inefficiently) high prices, increasing the likelihood of overshooting investments (i.e. boom and bust cycles), and cannot fully facilitate the required shift to a more flexible and less-carbon intense power mix.

Uncertainties regarding future price levels and the occurrence of scarcity price situations are additionally affected by a broader set of political and regulatory risks. Political risks may take many forms, including the political implementation of price caps as a measure to prevent occasional high scarcity prices. Also, investors cannot anticipate future market design adjustments that affect the price distribution. Similarly, the active removal of inflexible, baseload capacity affects the possibility of investing in efficient and flexible technologies.

43 Market completeness refers to the extent to which the full set of forward and spot markets and risk management tools are available for each product in time and space. Incomplete markets do not maximize efficiency (Stiglitz, J.E. (2001): Information and the change in the paradigm in economics. Nobel Prize Lecture).

Capital intensive technologies like solar PV and wind are more vulnerable to the above named uncertainties and risks than investment in fossil-fuel fired capacity, and thus more likely to suffer from high risk-premiums under the same market conditions. As high capital cost technologies, they depend on stable revenue streams from selling electricity in the market. Even small increases in the risk premiums of RES projects will increase the cost of capital and thus lead to a significant increase in project costs. The important point here is that other, less capital intensive investments are much less exposed in their cost and financing structure to the above described risks (see Box). This puts RES projects at a major competitive disadvantage when compared with conventional generation technologies.

Effect of market risk on the cost of capital-intensive and non-capital-intensive technologies

For two technologies, where one is capital-intensive but without fuel cost (e.g. onshore wind project, 80 percent capital cost) and the other is less capital intensive with fuel cost (e.g. CCGT technology, 20 percent capital cost), a rise in capital costs by 1 percent due to revenue risks (e.g. from 6 to 7 percent) would lift the LCOE of the wind project by about 8 percent and the LCOE of the CCGT project by only 2 percent. This means the wind project would have to generate substantively higher revenues in the same market to be profitable, as compared to the CCGT project.[44]

Regulatory risk: Politicians do not take the risk of outages and implement safety nets

A reliable and secure power system is of high importance for any economy. For this reason, power system reliability is often considered a public good. Even if, theoretically, an energy-only market might incentivise new investments and deliver system reliability, many politicians and regulators apparently doubt the effectiveness of the energy-only market. In practice, declining reserve margins in the power systems have triggered debates about the need to incentivize additional investments to "keep the lights on", be it full-blown capacity markets or "safety net approaches" such as capacity reserves or strategic reserves.[45] In most EU Member States, one or even several of these instruments have been implemented (see Figure 11). The introduction of such instruments and the public discussion surrounding them have increased uncertainty amongst market participants, making market-based investments into new capacity less likely.

Realistically, therefore, the question is not *whether* interventions in support of system reliability can be avoided, but *how they should look* to be commensurate with a power system in transition towards full decarbonisation.

The revenues of wind and PV are typically lower than average power market prices.

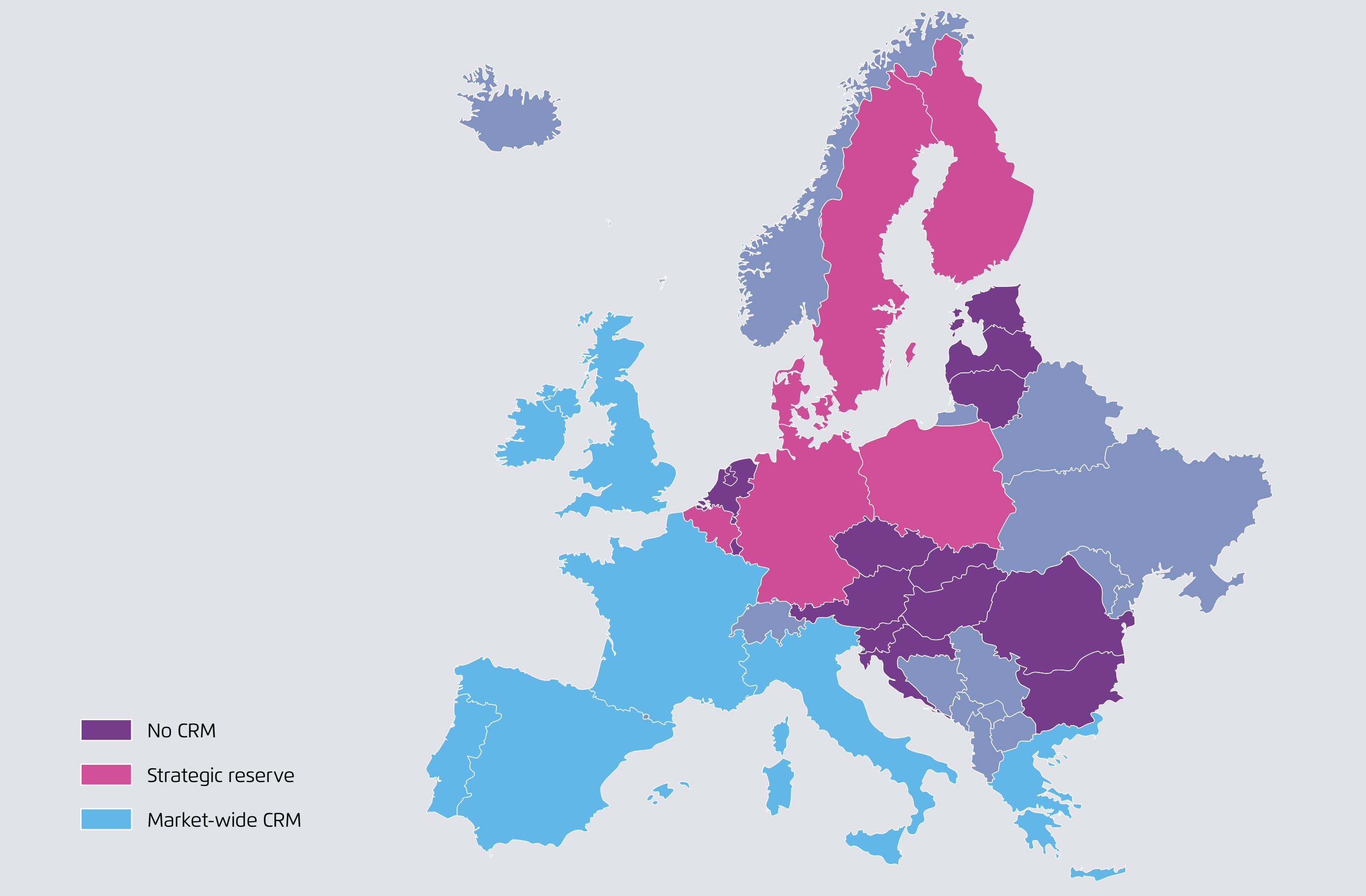
There is an ongoing and important academic debate concerning the electricity market prices achieved by RES installations during the hours they produce when the power system has a high share of variable renewables.[46] Beyond theory-based arguments, there is some evidence that a higher share of variable renewables is associated with falling market revenues for each kWh of vRES electricity produced. Some questions remain, however: does this reduction in market revenues decline slower or faster than the still falling LCOE of newly built RES capacity? Furthermore, does an increase in flexibility options in the power system result in a bottoming out of the market price? In other words: does the market value of wind and PV decline as a function of the speed of their deployment? Does their market value increase

44 Example adapted from Sartor et alii (2015), p. 8-14.

45 Capacity or strategic reserves address the political concern that the EOM might not build sufficient capacities. They do not reduce risks for the remaining capacities inside the EOM potentially yielding the "slippery slope effect": Over time, the size of the reserves becomes larger and larger because of lacking market-driven investments.

46 See, e.g. Agora Energiewende (2015): The Integration Cost of Wind and Solar Power and the references therein; Hirth., L. (2013): The Market Value of Variable Renewables, Energy Economics 38; Hartner, M., et al. (2015): East to west – The optimal tilt angle and orientation of photovoltaic panels from an electricity system perspective, Applied Energy 160.

Capacity mechanisms in the EU 2015 Figure 11



ACER/CEER (2015), own illustration

in relation to the speed by which the overall power system becomes more flexible? If the market revenues wind and PV achieve were to fall faster than LCOEs, this would support the argument that at higher shares of wind and PV, new investments in these two technologies are typically not able to be fully financed from wholesale market revenues.

Furthermore, at high shares of RES-e, the marginal price in the wholesale market will during an increasing number of hours be set by RES-e and nuclear, not by fossil fuel fired plants falling under the ETS. During those hours, the ETS will thus not add to the market price obtained by RES-e producers. The moment the last fossil fired power plant is not dispatching, the market price could drop to the marginal cost of nuclear and/or the marginal cost of RES-e installations – i.e. zero for wind and PV.[47] By 2030 at the latest, RES-e investors would anticipate such developments and not invest in new RES-e capacities unless there is some mechanism for generating stable market revenues, even in presence of large shares of zero-carbon capacity.

Again, the general theory of the EOM does not address the financing challenge resulting from the existence of high shares of zero-marginal-cost capacities in the market. It also fails to reconcile the key role played by wholesale power markets, which provide an effective dispatch signal, with the political imperative to transition to a zero-carbon power system over the course of a little more than two decades.

47 Depending on whether the supply or demand side is price-setting.

ETS #1: Oversupply paralyses the market and blocks any meaningful investment signal

The EU ETS is a quantity-based system. The price for ETS allowances emerges endogenously, when demand for allowances is consistently higher than supply. This, however, has not been the case for some years now. On the contrary, the ETS has consistently been oversupplied. The current surplus stands at approximately 2 billion allowances. This equals an emissions budget for 1 year. The only reason for certificate prices not to be zero despite this enormous oversupply is that allowances are "bankable", i.e. they only expire through use. The ETS allowance price of 4-5 euros per tonne of carbon thus reflects the expectation of market participants that allowances may be needed *in the future*.

The main reasons why the ETS is oversupplied are as follows:[48]

- → A significant initial over-allocation of allowances – since 2005, in any given year except 2008 more allowances were allocated to the market than CO_2 was emitted by the ETS participants. This initial over-allocation reflects political reluctance to err on the wrong side (i.e. by establishing too tight a cap).
- → A much larger than anticipated influx of emission credits from the project-based mechanisms under the Kyoto Protocol (Clean Development Mechanism and Joint Implementation), a large part of which merely consisted of "hot air" from Russia, Ukraine and China.
- → The occurrence of a financial and economic crisis in many parts of Europe, which has led to lower than anticipated economic activity and greenhouse gas emissions.

Furthermore technology-specific policies such as those on renewables or energy efficiency can also lead to lower demand for ETS allowances. However, here the development up to 2015 has been very much in line with the expected increase in the 2006 projections.

48 Agora Energiewende (2015): Role of ETS in the energy transition

Against this backdrop, EU legislators recently amended the EU ETS by creating a so-called "market stability reserve".[49] Furthermore, in July 2015 the Commission proposed, on the basis of the decisions taken by the European Council in October 2014, to increase the annual reduction factor of the overall emissions cap from 1.74 to 2.2 percent annually.[50] The legislative process on this proposal is ongoing.

The Market Stability Reserve

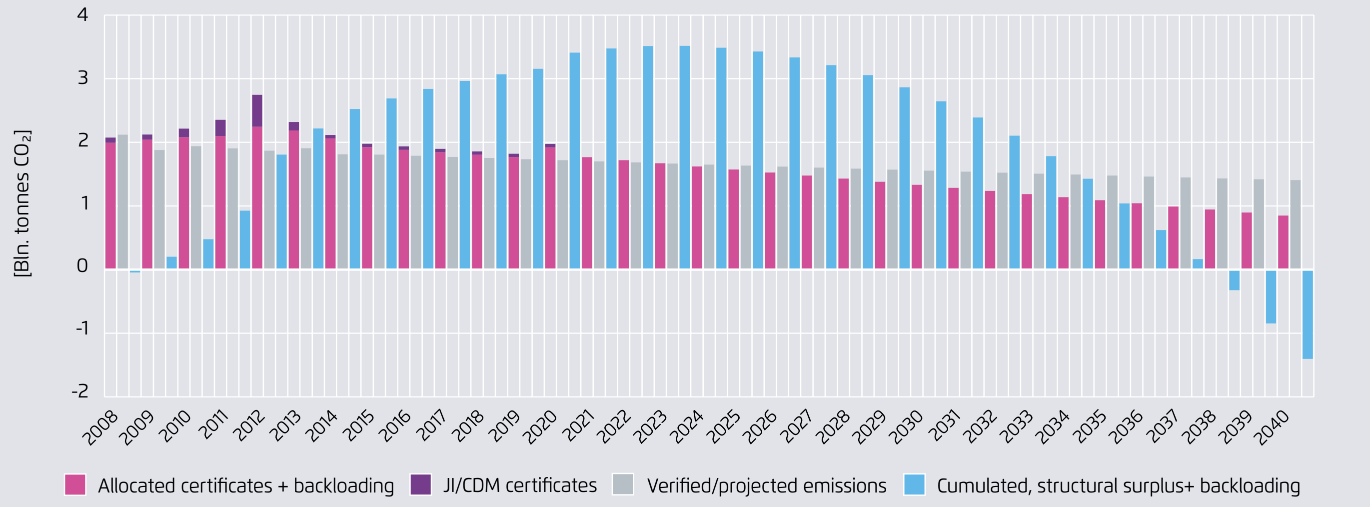
The main purpose of the market stability reserve (MSR) is to better buffer the ETS against external shocks, such as an economic crisis situation. This is a laudable objective. However, there are two major shortcomings:

- → *First*, the new MSR only removes 12 percent of excess allowances per year. Considering the current surplus of approximately 2 billion allowances and knowing that this will further increase, this means that – all else being equal – the general reserve margin of 833 million allowances will only be reached long after 2030. Before this date, the surplus allowances in the market will continue to be well above the amount considered as the necessary reserve margin for hedging.
- → *Second*, allowances moved to the MSR are not removed from the ETS for good. They are simply not actively traded. As soon as there is a relative scarcity of allowances in the market (whether through foreseen or unforeseen events), allowances will gradually be released from the reserve. This has three apparent implications:
  - First, from a price-formation perspective, it seems highly unlikely that the ETS will move to real and lasting scarcity during the 2020-2030 decade (see Figure 12). This also suggests that the ETS will not lift wholesale power prices to a level that will close the revenue gap of most new RES projects.

49 DECISION (EU) 2015/1814 of the European Parliament and of the Council of 6 October 2015 concerning the establishment and operation of a market stability reserve for the Union greenhouse gas emission trading scheme and amending Directive 2003/87/EC

50 COM (2015) 337 final of 15 July 2015.

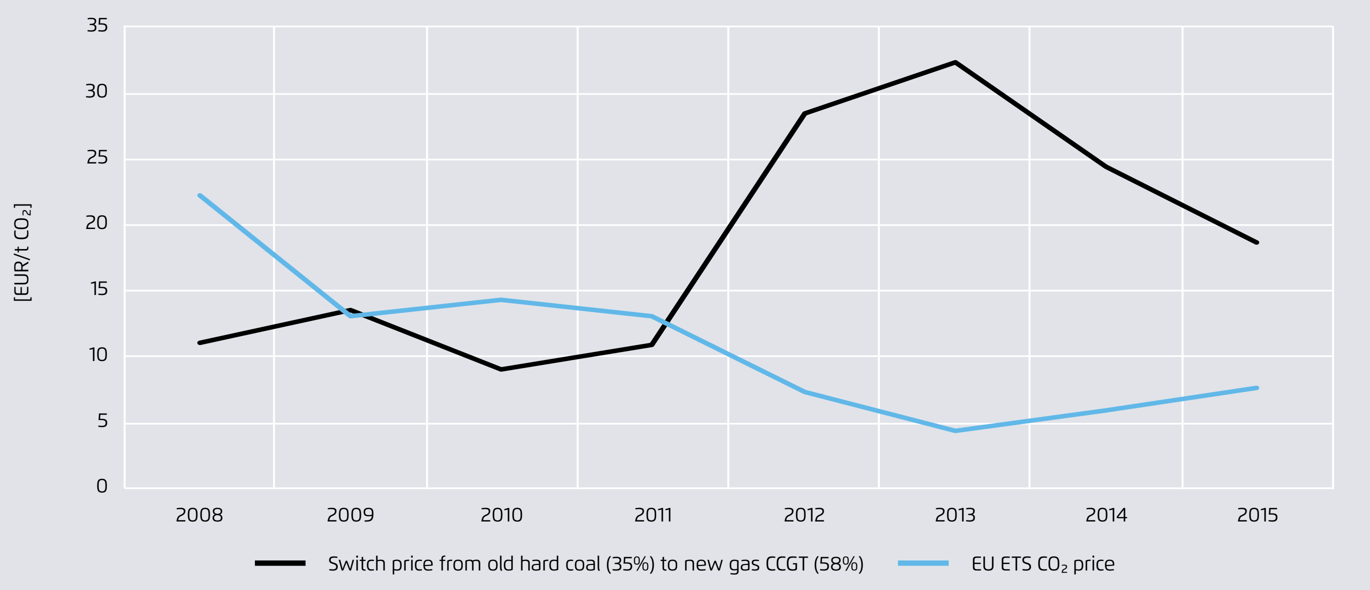
Cumulated excess certificates in the EU ETS 2008 - 2040 Figure 12



Own calculations based on EEA/EU ETS Data viewer and EEA (2015). Assumptions: Annual cap reduction: 1.7% p.a. in 2013 - 2020; 2.2% p.a. from 2021; Projected emissions reductions due to RES/Efficiency: 1% p.a. from 2015

- Second, the price for ETS allowances will most probably remain for several years significantly smaller than what is needed to reach the fuel switch between coal and gas (see Figure 13). This suggests that in all likelihood, the market will continue to lack a stable investment signal from the ETS to switch from more carbon-intensive coal to less carbon-intensive gas. It also means that cheap, coal baseload plants will continue to push more flexible generating resources out of the market.

Comparison of the hard coal-to-gas CO_2 switching price* and the actual CO_2 price in the EU-ETS Figure 13



BAFA, DEHSt, EEA, Lazard, Federal Statistical Office Germany, UBA, own calculations

* Assuming an electrical efficiency of 35% for (old) hard coal plants and 58% for (new) gas-fired plants.

- Third, from the perspective of preventing global warming, it does not make much difference *when* carbon emissions are released into the atmosphere. In order to reach the 2 degrees target, scientists estimate that a maximum of 1,000 Gt of CO_2 may still be emitted into the atmosphere over the course of the 21st century. So taking ETS allowances temporarily out of the market – as the MSR is doing – may slightly increase CO_2 prices in the emissions trading system, but it does not help to protect the climate. For this to occur, a permanent cancellation of the surplus would be needed.

Thus, while it is an economically efficient instrument in theory, the real world EU Emissions Trading System will deliver too little, too late, despite recent reform proposals.

ETS #2: Sufficiently high prices would not be accepted by European industry, limiting the transformation potential of the ETS for the power sector.

A quicker and more radical reduction of oversupply could help increase prices sooner. However, considering the track record of the ETS up to this point, and the high anxiety of policy-makers towards the risk of carbon leakage or concerns about a possible de-industrialisation of Europe, it is not likely that sufficiently high ETS allowance prices will be reached any time soon.

To put things into perspective: for zero-carbon investments to be "pulled" by the market under the current environment, studies indicate the need for a stable ETS allowance price of at least 60 euros per tonne of carbon.[51] The ETS price is less than 10 percent of this price at the time of writing. It is projected to reach prices above 60 euros per tonne of carbon only after 2040.[52]

51 See Deutsch et al (2014): Let's talk about risk: Why we need more than the EU Emissions Trading System to foster investment in wind and solar PV.

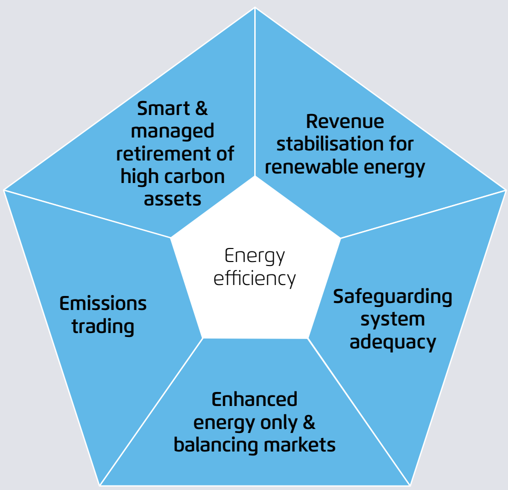
52 Draft EU Reference scenario 2015.

Part III The Power Market Pentagon

Against the backdrop of path dependencies, fundamental uncertainties about market dynamics, and insufficient investment signals from the EU Emissions Trading System, we consider the following five elements as important parts of a post-2020 power market design that is consistent with the triple objectives of transitioning to a fully decarbonised power system by 2050 while ensuring high security of supply and low transition costs:

- → a well-functioning, broad, liquid and – through further grid expansion and enhanced market coupling – increasingly EU-wide integrated wholesale market with low barriers to entry on both the demand and supply side in order to manage the flexibility challenge;
- → a European Emissions Trading Scheme that provides a long-term, declining cap on power sector emissions;
- → complementary EU-level measures enabling Member States with a high share of coal-fired power plants to chart a pathway out of coal ("smart & managed retirement");
- → market-based instruments for revenue stabilisation for RES investments paid through premiums on market prices or long-term contracts;
- → clear rules on government interventions to safeguarding system adequacy consistent with the need for increasingly flexible power systems and long-term decarbonisation strategies.

The Power Market Pentagon | Figure 14



Own illustration

Together, these five elements form the Power Market Pentagon (see Figure 14) In this section we explain the rationale for each element and describe the most important actions that should be taken.

As is graphically represented, we consider the Power Market Pentagon as part and parcel of the "energy efficiency" first principle, a systematic principle to prioritise investments in efficiency resources whenever they would cost less, or deliver more value, than investing in any available sources of energy supply and infrastructure.[53]

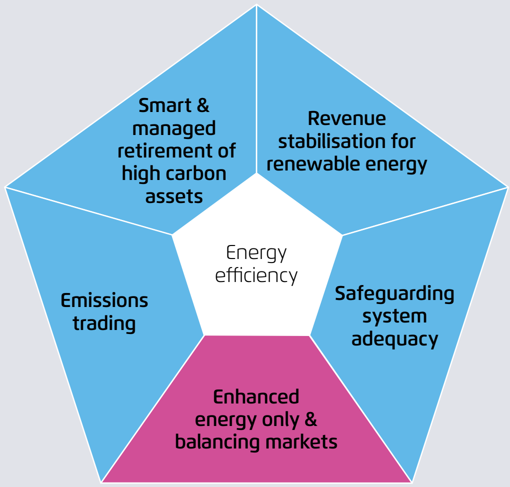
53 RAP (2015): Efficiency First: Key points for the Energy Union Communication

Element 1: Energy-only and balancing markets manage the flexibility challenge by steering supply and demand

Today's wholesale electricity markets in Europe are energy-only markets. Suppliers and consumers trade in kilowatt-hours, i.e. specific amounts of energy at a specific point in time. The price of electricity in the wholesale markets is determined by sorting the generation bids, from cheapest to most expensive, and intersecting it with demand bids. This mechanism, the so-called merit-order principle, ensures that power plants with the lowest operating costs are deployed first, followed by those with higher operating costs. As long as surplus generation is available, prices will correspond to the operating (or marginal) costs of the most expensive plant running in the system.

To tackle the real world challenges of today's power markets in transition, it is critical to *make markets fit for flexibility*. Indeed, both policymakers[54] and academics[55] acknowledge this is an objective of market reforms. The reforms discussed can be grouped around four pillars:[56]

The Power Market Pentagon Element 1



Own illustration

→ **Coupling energy markets and making them faster:** This would improve the efficiency of providing flexibility. For the short-term energy price (spot price) to serve as an undistorted dispatch signal, it is essential to make short-term energy markets faster and larger.[57] Coupling short-term markets across balancing areas and price zones reduces flexibility requirements due to geographical smoothing effects, yielding reduced peak load, and reduced wind and PV fluctuations – while also giving access to a larger set of balancing options, facilitating the more efficient supply of flexibility.[58] Faster intraday mar-

54 For political processes acknowledging the no-regret character of flexibilising power markets see, e.g. the European Commission's communication on launching the process on a new energy market design (COM(2015) 340 final), the Second Political Declaration of the Pentalateral Energy Forum of 8 June 2015 or the Joint Declaration for Regional Cooperation on Security of Electricity Supply in the Framework of the Internal Energy Market of the "12 electrical neighbours" from 8 June 2015.

55 RAP (2014): Power Market Operations and System Reliability: A contribution to the market design debate in the Pentalateral Energy Forum. Study on behalf of Agora Energiewende. Connect Energy Economics (2015): Pilot study electricity market 2015 ("Leitstudie Strommarkt 2015"). Neuhoff, K., Ruester, S., Schwenen, S. (2015): Power Market Design beyond 2020: Time to Revisit Key Elements? IEA (2014): The Power of Transformation

56 For further details, see RAP (2014): Power Market Operations and System Reliability: A contribution to the market design debate in the Pentalateral Energy Forum. Study on behalf of Agora Energiewende.

57 Undistorted energy market prices are a necessary requirement for efficient flexibility provision. Besides market prices, the design of surcharges and taxes (on top of market prices) affects the dispatch decisions of market actors. This is beyond the scope of this paper, however.

58 Fraunhofer IWES (2015): The European Power System in 2030: Flexibility Challenges and Integration Benefits. An Analysis with a Focus on the Pentalateral Energy Forum Region. Analysis on behalf of Agora Energiewende.

kets (shorter trading products like 15 minute products and reduced gate closure times) would allow trading closer to real-time, enabling market participants to actively react to new information. This would reduce short-term uncertainties and thus the need for operating reserves.

→ **Linking short-term market segments** to achieve market prices that reflect the real-time value of power. This maximises economic efficiency. The market should be designed to create stronger price linkages[59] between the different short-term market segments: that is, between the day-ahead, intraday and balancing energy markets.[60] Stronger linkages would enable the real-time value of energy and balancing resources to be better taken into account. More efficient price links between the short-term energy and balancing markets can be achieved with regulatory adjustments of the market design, including shorter contracting periods for operational reserves, alternate technical prequalification criteria for these reserves, and the implementation of shorter availability periods for the actual deployment of balancing energy. Improved linkages would empower new market actors who offer balancing services, including demand side response (DSR) and renewable energy and storage. Altogether, such reforms would contribute to the more efficient provision of power dispatch and flexibility services.

→ **Improving the predictability of scarcity prices** would reduce risks, support efficient investments and contribute to reliability. Refinement of the market design for energy and balancing markets would make prices more predictable and reduce associated market risks. Options in this regard include the adjustment of the methods used to set imbalance prices and/or the introduction of administrative demand curves that determine balancing market prices, thus increasing the stability of shortage prices (see Figure 15).[61] Prices would then better reflect the societal value of power supply. In turn, such adjustments would increase certainty about the revenues for new peaking capacity (be it a supply or demand side technology) and reduce the likelihood of involuntary load-shedding. As market power is a critical issue in situations with high shortage prices a comprehensive system for market monitoring needs to be in place. Also, such adjustments cannot (and arguably should not) completely eliminate uncertainty for investors. In this way, there is still a risk of boom-bust cycles. Finally, political acceptance of occasionally high wholesale-price peaks is required, yet this acceptance is needed in all energy-only market settings.

→ **Enable a level-playing field for demand-side and supply-side flexibility** in order to reduce total costs and maximise reliability. To meet increasing technical flexibility requirements in the power system, greater participation of the demand side is needed. Demand side response (DSR) can reduce total system costs, enable smoother integration of renewables and contribute to security of supply and the adequacy of the power system. In sum, a level playing field that ensures fair competition between supply-side, storage and demand-side options is needed to ensure a cost efficient transformation to a more flexible electricity system.[62]

Currently, some market and regulatory provisions prevent the emergence of a level playing field. This concerns, e.g. balancing market, where flexible consumers could potentially provide balancing services competitively, whereas technical prequalification requirements (e.g. prohibit-

59 Through opportunity cost pricing.

60 After short-term energy markets have closed, any occurring real-time deviations from the supply and demand equilibrium are balanced through the balancing markets operated by the transmission system operators. The costs of these balancing actions are then allocated to the market actors that have caused these imbalances through the so-called imbalance settlement mechanism.

61 In essence, both options would have similar results. For further details see, e.g. Hogan, W.W. (2012): Electricity scarcity pricing through operating reserves: An ERCOT window of opportunity. RAP (2015): Market Design in Context: The Transition to a Decarbonised Power Sector. Neuhoff, K., Ruester, S., Schwenen, S. (2015): Power Market Design beyond 2020: Time to Revisit Key Elements? Brattle (2012): ERCOT Investment Incentives and Resource Adequacy.

62 RAP (2014): Unlocking the Promise of the Energy Union: "Efficiency First" is the Key. Connect Energy Economics (2015): Action plan Demand Side Response. Study on behalf of Agora Energiewende.

ing pooling of resources or high minimum volume requirements) and contracting durations (e.g. availability requirements over extended time-periods like weeks, months or years) prohibit their actual participation.

While the above described changes to the design of the market are important preconditions for a more flexible and cost-effective power system, they will only have an effect if power market prices are sufficiently high to make flexibility options on the supply or demand side economically profitable. At present, wholesale power market prices in Europe are suppressed due to overcapacities and high shares of inflexible, cheap coal baseload capacity in the system.[63] The active removal of old, high carbon, inflexible capacity should therefore be an important element of the post-2020 market design (see element 3 below). The value of flexible, low-carbon capability in the market would furthermore be increased through a strengthening of the EU ETS (see element 2).

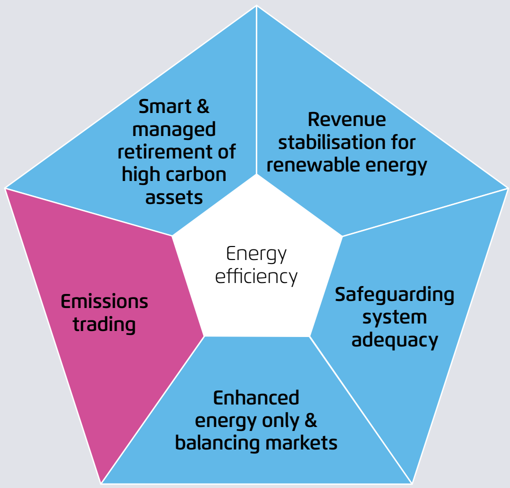
63 The argument and supporting figures are developed in Agora / RAP (2015): The Market Design Initiative and Path Dependency: Smart retirement of old, high-carbon, inflexible capacity as a prerequisite for successful market design.

Element 2: The EU Emissions Trading Scheme should provide a stable mid-level carbon price – and smartly interact with renewables, efficiency and smart retirement policies

The EU ETS is often referred to as the "flagship tool" of EU climate policy.[64] Its importance for EU climate policy is reflected by the simple fact that it covers 45 percent of EU greenhouse gas emissions. However, as shown above, the ETS is currently performing poorly. Specifically, it does not provide for carbon constraints, as the level of annual emissions in the ETS has been lower than the allocated allowances since the inception of the ETS in 2005 – with the sole exception of 2008. Given the possibility of banking excess certificates and the massive inflow of emissions reduction credits from JI/CDM credits, scarcity in the ETS is not expected to occur before the end of the 2030s. This forecast already takes into account the market stability reserve that will go into effect in 2019 and the linear reduction factor that is to be increased to 2.2 percent p.a. as of 2021, as decided by the EU heads of state in October 2014. As a consequence, the ETS does not provide a sufficient nor stable price signal for investments into low- or zero-carbon capacities at least until 2030.

In light of these shortcomings, several member states have introduced domestic measures that complement the EU ETS. The UK has announced it will quit coal power production by 2025 and it has introduced a CO_2 carbon support mechanism of £18, which is added to the EU ETS price. Given current EU ETS prices, this delivers a carbon price of around 30 EUR/t CO_2. In Germany, the government has decided to phase-out 15 percent of its lignite power plants by granting a "decommissioning premium", in order to reach its domestic 2020 climate target, and a vibrant discussion is taking place on a complete hard coal and lignite phase-out by 2040.[65]

The Power Market Pentagon | Element 2



Own illustration

Furthermore, the Dutch parliament has decided with a broad majority that the government should put forward a national coal phase-out plan, and the Danish and Swedish state utilities Dong and Vattenfall are converting their coal power plants to biomass or divesting from them. Lastly, in the aftermath of the Paris agreement, the French government has proposed that the EU or at least a relevant group of countries should agree to an ETS minimum price of 30 EUR/t CO_2.[66]

Given this situation and the different options for the reform of the EU ETS on the table, the question to be answered is the following: What role should the EU ETS play in a pragmatic, solution-oriented instrument mix? In recent years,

64 Commission press release "Transforming Europe's energy system – Commission's energy summer package leads the way", IP/15/5358 of 15 July 2015.

65 Agora Energiewende (2016): Eleven Principles for a Consensus on Coal: Concept for a stepwise Decarbonisation of the German power sector.

66 See *http://www.developpement-durable.gouv.fr/IMG/pdf/16038-GB_prix-carbone_propositions-france-ue_DEF2_light.pdf*

research on the climate policy mix[67] suggests that emissions trading systems should not be viewed as "the one-off solution instrument" that discards all other climate policy instruments (as simple textbook economics would suggest). Rather, it should be viewed instead as one climate policy tool that needs to be complemented by other instruments such as energy efficiency standards or regulation to retire high carbon assets.

Beyond the need for supplemental policy tools, as explained in the remaining sections of Part III, there are three further reasons as to why the ETS alone is not enough:

- → One lesson learnt from the past three decades of carbon pricing systems is that policy-makers are afraid of setting the cap with the stringency needed to meet carbon reduction goals. Thus, the resulting carbon price usually fails to reflect the marginal abatement costs that would be associated with a cap. Given the true social cost of carbon, which are usually estimated at around 70-80 EUR/t CO_2, it is unlikely that policy-makers in countries with large high-carbon industries will agree to any instrument the produces such high carbon prices in the near term.[68] Therefore, additional instruments to drive the deployment of zero-carbon technologies, thereby gradually pushing out high carbon assets are needed.
- → There is a widespread recognition in the scientific community that already today, especially in the field of energy efficiency, numerous CO_2 abatement measures exist that could be tapped at negative CO_2 costs. However, the resulting benefits, e.g. more efficient electric appliances, are not sufficient to motivate changed consumer purchase behaviour. The same applies to the use of energy by non-energy intensive companies. Therefore, efficiency standards for electrical appliances and other energy efficiency related instruments are needed in order to tap these low-cost CO_2 abatement potentials, as price signals fall short.[69]
- → Carbon prices are distorted by the specific market design. If zero-carbon options like wind or solar with no or extremely low short-term marginal costs start to significantly impact price formation in the energy only market, enormously high CO_2 prices would be needed to recover their full costs although these technologies are competitive if compared at the basis of levelised costs of energy.

Thus, the role of the ETS in the European climate policy mix should be redefined in the following way:[70]

- → 1. The main role of the EU ETS in the energy sector should be to deliver a meaningful carbon price that helps to shift the energy mix from high-carbon fossil fuels to lower-carbon fossil fuels (i.e. from lignite to hard coal, and from hard coal to gas). Given current coal and gas prices, a CO_2 price of around 30 EUR/t CO_2 would suffice to deliver on this goal.
- → 2. The EU ETS is not the right instrument for driving the adoption of zero-carbon assets like renewables in the power market, nor for fully pushing high carbon lignite assets out of the system. Given the current all-time-low coal, gas and oil prices, this would require carbon prices of >60 EUR/t CO_2, which neither seem politically realistic nor desirable, given potential negative effects on energy-intensive industry.

67 OECD/World Bank (2015): The FASTER Principles for Successful Carbon Pricing. Hood, Christina (2013): Managing Interactions between Carbon Pricing and Existing Energy Policies: Guidance for Policymakers. Paris: International Energy Agency; Schmalensee, Richard and Robert Stavis (2015), Lessons Learned from Three Decades of Experience with Cap-and-Trade. Washington, DC: Resources for the Future. Matthes, Felix C. (2010): Greenhouse Gas Emissions Trading and Complementary Policies. Developing a Smart Mix for Ambitious Climate Policies. Öko Institute, Berlin.

68 There are many different estimates of the true social costs of carbon. For example, the US EPA uses for its policy assessments carbon costs of \$37/t CO_2 (prices of 2007), the Stern Report "The economics of climate change" of 2006 estimated them to be at \$86/t CO_2. A PwC review of 60 recent papers containing 350 different estimates resulted in an average of \$87 in 2014, see http://www.climatechangenews.com/2015/01/19/costing-the-climate-four-ways-to-price-carbon/

69 See IEA (2011): Summing up the parts - Combining Policy Instruments for Least-Cost Climate Mitigation Strategies.

70 See Partnership for Market Readiness/International Carbon Action Partnership (2016): Emissions Trading in Practice: a Handbook on Design and Implementation.

→ 3. The cap within the EU ETS should interact smartly with the carbon reduction achievements that are delivered by the other climate instruments that affect the EU ETS sector, i.e. feed-in tariffs, energy efficiency measures and smart retirement instruments. Thus, any CO_2 reductions that go beyond their projected baseline need to be deducted from the cap in order to preserve the economic efficiency and environmental integrity of the cap.

→ 4. As an EU-level instrument, the EU ETS should interact with and enable national climate policy instruments. The EU is currently composed of 28 member states, each with different parliamentary and budgetary cycles. Hence, the political window of opportunity for taking stronger national climate policy measures will normally open at different points in time. The Paris Agreement, which will be ratified by the EU and by its member states, strengthens the notion that individual member states should be able to progressively "ratchet up" their commitments by moving forward with stronger national measures. In order to have a positive effect on the global climate, any additional emissions reductions from such action needs to be reflected in the EU ETS, by reducing the overall cap.

As one consequence, the following three measures need be taken in order to invigorate the EU ETS:

→ **Introduce a cancellation mechanism for additional domestic or European climate policy measures:** Whenever individual member states enact climate policies that affect the EU ETS or European policies on renewables, efficiency or smart retirement, and these policies turn out to be more effective than projected, the EU cap should be adjusted accordingly. For example, if Germany introduced a coal phase-out law, it could delete from its share of certificates in the market stability reserve the amount that would be equivalent to the emission reduction effect of this law. The same would apply if there was more than 50 percent share of RES in the EU power market by 2030, as this is the expected amount given current projections based on the October 2014 Council decisions. With such a mechanism, the EU ETS and additional policies at both the European and domestic levels become mutually empowering, interacting smartly rather than conflicting with each other.

→ **Stabilise the EU ETS price through a minimum price:** The EU could introduce a minimum carbon price – say, 30 EUR/t CO_2. This would imply that no ETS allowance would be auctioned by the EU member states at less than 30 EUR/t CO_2. This minimum price should then increase on an annual basis, such as 1 EUR per year.

→ **Cancel the EU ETS surplus:** The EU ETS surplus currently amounts to some 2 billion allowances and will increase to more than 3 billion in the early 2020s. If this surplus is cancelled, the EU ETS would again generate a scarcity-based and effective price that drives operations and at least some investments towards low-carbon options This surplus cancellation could be done by one of the following options:

a. In combination with an ETS minimum price: If in any given year the annual allotment of allowances was not completely sold off at the minimum price, the remaining certificates would be cancelled (instead of banked or placed in the market stability reserve), because otherwise this oversupply would add to the EU ETS surplus.[71]
b. Cancel the backloaded allowances that will enter the market stability reserve in 2019 (900 million tonnes) and suspend the annual ETS allowance auction in 2021 (950 million tonnes). This would delete 1.85 billion certificates from the market, thereby deleting most of the surplus.
c. Cancel excess certificates in the market stability reserve on a regular base (e.g. whenever the MSR exceeds the upper bound of 833 million certificates or through a vintage system).
d. Introduce a higher emission reduction factor than 2.2 percent p.a. as of 2021.

71 This is different to the recent proposal by the French government, as according to the French position the unused certificates would be placed in the market stability reserve and thus be released back into the market at a later point in time.

With these three reforms, the EU emissions trading system could again become an important and meaningful instrument in the EU climate policy mix. It would provide a stable, mid-level carbon price and smartly interact with renewables, efficiency and smart retirement policies.

If it is not achievable to agree on them at an EU-wide scale, it should be explored if and how these types of instruments could be implemented in the framework of the different regional electricity markets.

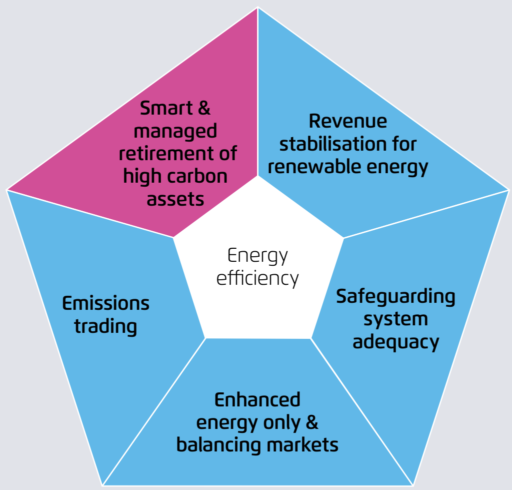
Element 3: Smart retirement – The active removal of old, high carbon, inflexible capacity

Europe's energy transition requires the large-scale deployment of renewable energy. But to be cost-effective, the adoption of renewables needs to go hand in hand with a broader system transition to a qualitatively different, much more flexible capacity mix. Achieving a cost-effective decarbonisation pathway in Europe will require political will and a commitment to break path dependencies created by legacy investments in high-carbon, inflexible assets.[72]

Given the right of member states to determine their energy mix, primary responsibility for the active removal of old, high carbon and inflexible generation capacity rests with national governments. After the historic climate agreement struck in Paris various member states have been considering the accelerated phasing out of coal, including the United Kingdom, Germany, the Netherlands and Denmark.

However, part and parcel with such national discussions is how they link to EU-level rules and how they could usefully be *complemented by EU-level action*. In the preceding section on the ETS, we already explained how the possibility of a mechanism for cancelling surplus allowances resulting from additional national actions would enhance the ability of such initiatives to make a meaningful contribution to climate protection. However, the active removal of old, inflexible, and high carbon baseload capacity would also facilitate the integration of higher shares of renewables into the power system, thereby make the market design reforms discussed above more effective while helping to keep the EU's energy transition on a cost-effective pathway in terms of system costs.

The Power Market Pentagon — Element 3



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Complementary EU-level action to support national smart retirement initiatives should include:

→ *Efforts to close gaps in the Industrial Emissions Directive:* From 1 January 2016, the EU Industrial Emissions Directive (IED) will further tighten air pollution emission limits for large combustion plants. This will likely contribute to further plant closures in some member states. However, some IED derogations include relaxed emission limits for older plants if these are operating less than 1500 hours. A continuation of this derogation beyond 2020 is currently being discussed.[73] Closing IED exemptions for older plants

72 This section expands on Agora Energiewende and RAP (2015): The Market Design Initiative and Path Dependency: Smart retirement of old, high-carbon, inflexible capacity as a prerequisite for a successful market design, Background paper, November 2015.

73 For further information see EIPPCB webpage: <http://eippcb.jrc.ec.europa.eu/reference/lcp.html>.

would strengthen national initiatives to remove inflexible, high carbon baseload capacity.

- A further option for actively removing old, inflexible, high-carbon baseload is making use of an *appropriate emission performance standard (EPS) for the carbon emissions of power generators*. Existing EU climate and energy rules offer various options where such EPS could be referenced. This includes state aid decisions on national capacity mechanisms,[74] where minimum demands on the carbon intensity of power plants benefitting from a reserve mechanism would lower the risk of high-carbon lock-in. Since the EIB has recently put in place a carbon EPS for its own lending activities, further reference to this EPS could also apply where the EIB is only involved in project selection or as one financier among others.[75]
- A further opportunity for highlighting the particular challenge of old, inflexible, high-carbon baseload capacities to Europe's energy transition exists with respect to the *national energy and climate plans* that will be developed in context of the EU Energy Union.[76] This planning and reporting system will include *fairly detailed planning tasks for the 2020-2030 decade and more strategic, long-term planning component* that reaches up to 2050.[77] In both contexts, it will be important to put a spotlight on the issue of system adequacy and existing over-capacity, how the flexibility challenge is being addressed and the planned evolution of carbon intensity in the power sector. On the latter point, an emissions performance standard might provide useful benchmarks.
- The planned revisions of the *EU Electricity Market Directive*[78] and of the *EU Renewable Energy Directive*[79] also provide an opportunity to oblige all Member States and system operators to undertake – in view of the expected 50 percent share of renewable power in the EU system by 2030 – a comprehensive and transparent flexibility check of their respective power systems in consultation with energy stakeholders. Such assessments should then be translated into national and regional flexibility roadmaps that would provide a useful reference point for relevant sections of the national energy and climate plans.
- At last, the *current and future EU budget* should offer some opportunities for the Commission to assist member states, particularly those with GDP per capita below the EU average (e.g. Poland or the Czech Republic), in managing the economic and social consequences of political decisions to break path dependencies created by legacy investments in old, inflexible, high-carbon baseload capacities, particularly if these are associated with mining activities.

In *Germany*, for instance, a phasing out of coal fired generation would also entail a closure of lignite mines, which requires significant follow-up investment (for example, to recultivate landscapes). For those regions that are economically dependent on lignite mining activities, it will be important to actively manage the necessary structural changes, to avoid disruption and to develop alternative opportunities for workers who will lose their jobs.[80] A similar situation would be expected in *Poland*, where in coming years several coal mines will be closed. Particularly in the Silesia region, it would seem necessary to assist in the transition – both in terms of socio-economic adaptation and environmental protection/rehabilitation.

74 See section 3.9 in European Commission, Guidelines on State aid for environmental protection and energy 2014-2020, Offical Journal C 200, p.1 of 28.06.2014.

75 European Investment Bank (2015): Climate Strategy: Mobilising finance for the transition to a low-carbon and climate-resilient economy, 22 September 2015.

76 See COM (2015) 80 final of 25 February 2015 "A Framework Strategy for a Resilient Energy Union with a Forward-Looking Climate Change Policy", 17-18; And COM(2015) 572 final of 18 November 2015 "Guidance to Member States on National Energy and Climate Plans as Part of the Energy Union Governance".

77 See for example IDDRI, ecologic, ClientEarth (2015): Supporting delivery of climate ambition through the Energy Union

78 Directive 2009/72/EC.

79 Directive 2009/28/EC.

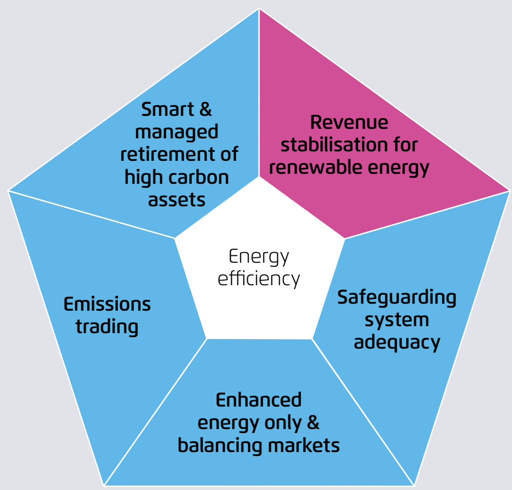
80 See principles 7 and 8 in Agora Energiewende (2016): Eleven Principles for Reaching a Consensus on Coal.

Element 4: Providing for stable market revenues for new RES-e investments

In discussions on the 2030 climate and energy framework, there is widespread assertion that by 2020 mature renewable energy technologies will be able to stand on their own economic feet and generate sufficient revenues from the EOM. As we have shown above,[81] an analysis of power market realities does not support such view. There are:

→ *factors external to the power market* that cannot be controlled by market participants and that have a profound impact on the potential revenues of renewable energy projects (e.g. projected ETS certificate prices; the evolution of prices for oil, coal and gas; the quantity and quality of the incumbent power mix).
→ *shortcomings in the current power market design*, including a lack of liquid intra-day markets, lack of sufficient access to ancillary services, lack of flexibility options, lack of market rewards for flexibility options, etc.
→ *cheap and inflexible baseload coal capacity* in the system that block a cost-effective transition.
→ *potential cannibalizing effects* amongst market revenues available to RES producers at high RES-e market shares.

The Power Market Pentagon Element 4



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Thus, we consider the dogma that renewables will no longer need support in the 2020s as analytically and politically unsound. In addition, it is also *unnecessary* to establish the expectation of market-based RES financing after 2020, since the move to competitive tendering of new RES capacity means that markets will show when and where conditions for the fully market-based recovery of investments in renewable energy projects are reached and where some revenue stabilization is needed and to what extent.

The EU-level framework of laws, policies and measures relevant to renewable energy is important for providing investors with confidence and stability to invest into RES-e capacities in Europe. Stable and reliable conditions are seen as lower risk, which translates into lower costs for project developers and lower rates of return needed to make an investment profitable. Lower rates of return means that – at the same power price – low risk projects will need no or less help in closing possible revenue gaps.

Full implementation of the *current Renewable Energy Directive* and the national targets it establishes for member states is important for maintaining confidence in the EU's commitment to renewable energy. This requires an early and clear political signal by the Commission that it will take member states to court if they do not deliver on their respective national targets.

Important elements in the *revised Renewable Energy Directive* that would strengthen certainty for investors are:

81 See Part II.

- a clear statement that Member States are allowed to put in place revenue stabilisation mechanisms to close gaps between projected revenues from electricity sold in the market and needed returns on investment. There are various mechanisms available to this end (feed-in tariffs, market premiums). Such interventions could occur at a national level (as is currently the case) or could be coordinated at a regional level. The latter would create more opportunities for consistent planning of RES deployment and grid infrastructure development.
- Importantly, competitive bidding for the construction of new capacities will identify where and when project developers and investors regard market conditions as sufficiently stable in specific member states to allow for project development without some additional revenue stabilisation in place.
- A provision ensuring that the established EU targets for 2020 RES shares must be met by member states as an absolute minimum. It should furthermore be established that only efforts beyond the respective 2020 targets will be considered as additional contributions for meeting the EU-level 2030 RES target. Clarity on this point is important, since a significant amount of existing RES capacity will need to be replaced in the 2020-2030 decade.[82]
- Establishment of a binding and enforceable principle ruling out the possibility that national governments retroactively devalue investments made on the basis of multi-year government commitments for stabilising revenue flows (in form of long-term contracts, such as feed-in premiums).
- Maintaining the principle of priority grid access and priority dispatch.
- Translating some elements of RES support schemes currently addressed in environment and energy state aid guidelines into ordinary EU legislation.[83] This would help to clarify the scope for technology-specific measures, aid the siting of new RES capacity, and contribute to cross-border participation in national renewable support schemes, among other benefits.
- Adoption of an obligation for member states to identify their planned contribution to reaching the EU's 2030 renewable target in their national energy and climate plans (NECPs). Furthermore, the NECPs must be legally effective and firmly established within the member state's legal system so that it can serve as a reference point for more concrete energy system choices at national, sub-national and regional levels.
- Establishing an obligation that each member state undertake – based on a consultation with energy stakeholders – an assessment and ranking of existing barriers to the development of RES projects and their market integration.
- Incentivizing member states to remove the most important and costly barriers to RES by making commitments to removal of barriers as a precondition for access to an EU mechanism in order to de-risk RES investments.
- Clarifying in the new framework how additional efforts for closing an possible gap between national contributions and the EU-level RES target would be shared amongst the member states.

82 A. Held, M. Ragwitz et alii (2014): Implementing the EU 2030 Climate and Energy Framework. Issue Paper No 2 of 8 December 2014

83 See section 3.3. in European Commission, Guidelines on State aid for environmental protection and energy 2014-2020, Offical Journal C 200, p.1 of 28.06.2014.

Element 5: Safeguarding system adequacy

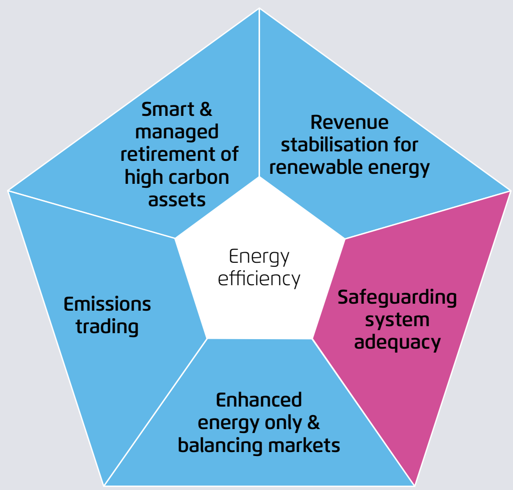
Depressed wholesale prices and insufficient revenues for all types of resources are often characterised to signal upcoming capacity shortages, rather than a welcome reduction in overcapacity. This is of major concern for discussions on safeguarding system adequacy.

As shown above, Europe's energy transition needs to build on an increasingly flexible mix of resources to evolve along a cost-effective pathway. Safeguarding system adequacy will thus increasingly become a dynamic issue: it is not only about "*how much*" capacities are needed, but increasingly about "*what kind*" of capacities.

As regards *establishing the need* for measures to safeguard system adequacy:

→ A key pillar of this element is that system adequacy is assessed on a cross-border regional level for both cost-efficiency and reliability reasons. Regional system adequacy assessments lower the costs of achieving a reliable power system and reduce the need for flexibility in the system. For a given system adequacy standard, the quantity of required resources decreases and the options for balancing the system expand as the market size increases.[84] Peak load periods are decorrelated among neighbouring countries, so is the feed-in from variable renewables, especially wind power. This means that countries can benefit from geographical smoothing effects. In turn, the regional residual load peak is lower than the sum of the national residual load peaks and fewer capacities are required to meet the residual load.

The Power Market Pentagon — Element 5



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→ In addition to ongoing efforts to improve the methodology of regional system adequacy assessments (e.g. properly taking into account the role of demand response, renewables and interconnections), the regionalisation of such reporting oversight has to be discussed to avoid potential biases in national perspectives.

→ The regional governance can take various forms, from improved cooperation of existing institutions to new, "stronger" institutions with a regional mandate. At any rate, a regional assessment of system adequacy can more properly inform national decision makers on whether a reliability issue in domestic power markets is on the horizon. Therefore, adequacy assessments with a regional scope should be a requirement for the introduction of domestic capacity remuneration schemes.

84 See the first joint generation adequacy report of the TSOs of the Pentalateral Energy Forum region (Pentalateral Energy Forum Support Group 2: Generation Adequacy Assessment, March 2015). RTE (2015) assesses in its 2015 Edition Generation Adequacy Report for France that without taking into account cross-border exchanges, a domestic capacity deficit exceeding 4.5 GW (up to 8 to 10 GW) would prevail in average peak periods until 2020. This highlights the case for a regional system adequacy assessment.

As regards *interventions to address system adequacy and to remunerate "capacity" in various forms*, it seems critical that such interventions are consistent with the *long-term decarbonisation pathway of the EU-28 and each of its member states and contribute to enhancing power system flexibility*.

The most important instruments under discussion are strategic or capacity reserves, "energy-based" capacity remuneration within energy markets, and explicit capacity remuneration mechanisms (CRMs) that are implemented simultaneously in energy markets.

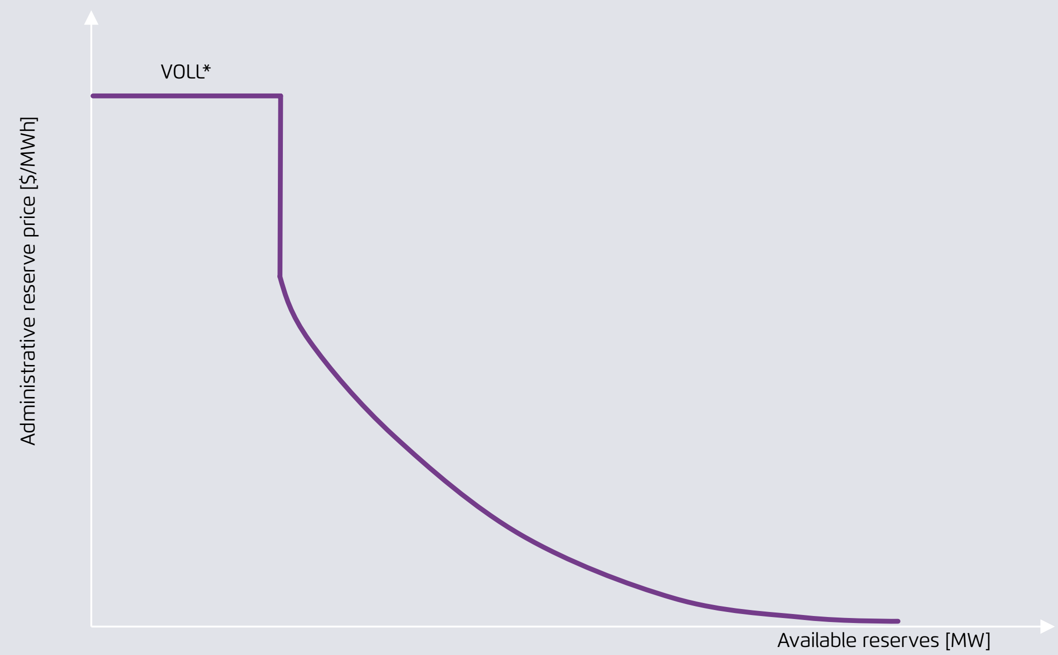
- Strategic or capacity reserves operate fully outside the energy and balancing markets and are only activated in case the power market fails to match supply and demand.[85] They address political concerns that the EOM might not build sufficient capacities. As such, strategic reserves do not reduce market risks for capacities inside the EOM.[86] As strategic reserves operate outside the energy markets, their creation is less critical from the perspective of long-term decarbonisation and flexibilisation requirements.
- Remunerating capacity through energy-based payments[87] works through improved short-term energy and balancing market design (see also Element 1 of the Power Market Pentagon); specifically through the administrative adjustment of real-time balancing or imbalance pricing methodologies. These adjustments add a price reflecting the value of the available reserves. The added price smoothens, or "stabilises", scarcity prices and decreases price uncertainty, thus contributing to decreasing investment risks (see Figure 15). Energy-based capacity

85 Full outside market operation is important to avoid that strategic reserves implicitly (or in case of activation directly) cap energy prices.

86 This could yield the so-called "slippery slope effect": Over time, the size of the reserves becomes larger and larger because of lacking market-driven investments.

87 RAP (2015): Market Design in Context: The Transition to a Decarbonised Power Sector.

Administrative adjustment of prices for reserves in the Texas electricity market — Figure 15



Own illustration based on Potomac Economics (2015)

* Value of Lost Load

remuneration would be consistent with flexibilisation requirements if the price curve for calculating such remuneration is set appropriately.
- Finally, investment signals for technologies operating inside the energy market can be complemented by explicit capacity remuneration instruments. In this regard, it is crucial that these instruments reflect the difference in value between resources with different operational capabilities. Efficient energy and balancing markets remunerate flexible technologies more than inflexible ones, so should capacity/capability remuneration instruments. Hence, resource capability rather than capacity needs to be their primary focus.[88] Thus, capability mechanisms are consistent with flexibilisation requirements. They are consistent with long-term decarbonisation requirements if constraints regarding the emission performance are implemented. Accordingly, provisions should be part of future state aid guidelines and security of supply directives.[89]

With a view to the energy transition, it is key that interventions in support of system adequacy incentivise flexible technologies and avoid the lock-in of inflexible and high-carbon assets. In our view this suggests that the EU-level framework for safeguarding system adequacy should also include the following obligatory elements:

- All member states should be obliged to elaborate national and/or regional roadmaps on enhancing power system flexibility. Such roadmaps would constitute an important reference point for establishing that government interventions for safeguarding system adequacy are consistent with the increasing flexibility needs of an energy system in transition.[90]
- In context of the EU Energy Union governance, Member States are expected to elaborate integrative energy and climate plans with fairly detailed planning for the 2020-2030 decade and more strategic long-term planning reaching up to 2050.[91] These plans should be used as a reference point for establishing that government interventions for safeguarding system adequacy are consistent with medium and long-term decarbonisation objectives.[92]

88 RAP (2012): What Lies "Beyond Capacity Markets"? Delivering Least-Cost Reliability Under the New Resource Paradigm.

89 The Security of Electricity Supply Directive (Directive 2005/89/EC) and the Guidelines on State aid for environmental protection and energy 2014-2020 (EC, 2014) do not contain specific provisions regarding long-term decarbonisation and flexibilisation requirements. The latter acknowledges that CRMs may be in contradiction with phasing out harmful subsidies for fossil fuels.

90 Note that the "12 electrical neighbours" have agreed on a "flexibility check" and accordingly analyse national regulations with the aim to minimise any negative impact on, and if possible increase, system flexibility (Joint Declaration for Regional Cooperation on Security of Electricity Supply in the Framework of the Internal Energy Market (2015)).

91 See IDDRI, ecologic, ClientEarth (2015): Supporting delivery of climate ambition through the Energy Union.

92 Compare also the Commission Staff Working Document on Generation Adequacy in the internal electricity market – guidance on public interventions (SWD(2013) 438 final), where it is pointed out that capacity mechanisms should not increase carbon intensity and should be consistent with decarbonisation objectives.

Conclusions

The EU's climate change objectives demand a full decarbonisation of Europe's power sector by 2050 at the latest. Importantly, the successful climate summit in Paris in December 2015 demonstrates that Europe is not alone in this endeavour.

As we have shown, wind and solar PV will provide the backbone of the EU's future zero-carbon power system. The reason is straight forward: Even including the integration cost, they are cheaper than any other new zero-carbon technology. To cost-effectively integrate progressively higher shares of volatile renewable electricity, the power system must react flexibly on the supply and demand side to the more variable patterns of electricity generation from wind and solar PV.

Research on a cost-effective transition pathway shows that enhanced power system flexibility can be achieved at significantly lower system costs, if the share of inflexible resources is decreasing while increasing the share of flexible resources. Put differently: a cost-effective transition requires that the increase in wind and solar PV is accompanied by a system shift to a qualitatively different, more flexible capacity mix.

This basic finding puts the spotlight on the investment signals given by power markets in Europe. Energy statistical data on the evolution of the generation mix in Europe and recent figures on investment patterns into renewable energies indicate that the EU's current approach to a market based decarbonisation does not function as it should.

Many of the shortcomings of the current framework can be traced back to solutions based on an overly simple textbook economics approach consisting of an Energy Only Market and the EU Emissions Trading System. The paper explained the basic assumptions behind this approach and why it will almost certainly deliver too little, too late.

In contrast, we propose to base Europe's energy transition on a **Power Market Pentagon**. This pragmatic and solution-oriented approach would indeed maximise the value of the energy only market and the established emissions trading system, but expand it by three elements:

→ (i) the smart retirement of inflexible high carbon capacity from the system,
→ (ii) measures to provide stable market revenues for new RES-e investments, and
→ (iii) measures for safeguarding system adequacy.

In addition to explaining why each of these elements is needed to overcome practical shortcomings of the simple textbook economics approach, we have also developed for each element a concrete list of the most immediate measures that should be taken for advancing Europe's energy transition.

Here, we offer further reflections on the interactions between the five elements of the Power Market Pentagon. Before doing so, it seems important, however, to stress again the fundamental importance and moderating effect of **energy efficiency** and the **energy efficiency first principle** on the power system transition challenge described at the beginning of this paper.

Enhancing energy efficiency will reduce the absolute amount of electricity from renewable sources needed for fully decarbonising the power system. Increases in energy efficiency thus also imply that less infrastructure investments are needed at transmission and distribution level. Increases in energy efficiency further mean that more inflexible high-carbon assets can be retired without compromising system adequacy. A further reformed EU Emissions Trading System would smartly interact with increases in energy efficiency and ensure that these are also effective from a climate protection perspective. For all these reasons we regard energy efficiency policies as part and parcel of the Power Market Pentagon approach developed in this paper.

Reflecting at the **interactions between individual elements of the Power Market Pentagon**, we observe that measures making markets fit for flexibility (Element 1) are of no regret character in all situations. Faster, more flexible and liquid power markets will in particular ensure a cost-effective absorption of progressively higher shares of volatile renewable electricity (Element 4).

The effectiveness of measures under Element 1 hinges to some extent on the active and smart retirement of inflexible high carbon assets from the system (Element 3). The need for smart retirement measures in turn arises because of currently lacking economic incentives from the EU Emissions Tradition System (Element 2). The EU Emissions Trading System should therefore be reformed in such a ways that it would lead to a mid-level carbon price that would shift the energy mix from high carbon to low carbon fossil fuels.

While a stable mid-level carbon price would ensure a fuel shift from high-carbon coal to lower-carbon gas, it will not be sufficient for pulling the scale of investments into new renewable energy capacity needed to cost-effectively transition to a fully decarbonised European power system. Measures providing stable market revenues for new RES-e investments (Element 4) will therefore remain an important element of power market design in Europe.

The system transition demanded by long-term decarbonisation objectives puts all power system participants under stress. The need to maintain power system reliability during the transition frequently triggers discussions about complementing the energy only market by market-wide capacity mechanisms or "safety net approaches" such as capacity reserves or strategic reserves. The Power Market Pentagon approach makes apparent that interventions to safeguard system adequacy (Element 5) must be consistent with long-term decarbonisation objectives as well as enhanced power system flexibility. We propose specific measures that would help establishing consistency.

Thus, all elements of the Power Market Pentagon interact with each other and should be looked at holistically. This is a tedious task, making life for market designers more difficult than just referring to simple textbook economics. However, following the Power Market Pentagon approach developed in this paper gives policy makers the tools needed to deliver a low-carbon-low-cost power market system under real world conditions – and that is what is needed in order to fully decarbonise the European power sector within the next 30 years.

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Agora Energiewende is a joint initiative of the Mercator Foundation and the European Climate Foundation.