WindEurope position on Market Design

Driving investments towards a climate-neutral and energy secure Europe

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WindEurope

EXECUTIVE SUMMARY

Europe is committed to becoming climate neutral by 2050. This requires ramping up wind capacity from 190 GW today to 1,300 GW driving the renewables-based electrification of our economy. The current geopolitical situation and resulting energy crisis put into even sharper focus the need to accelerate the transition to home-grown zero-carbon energy. This paper recommends the required adjustments to the energy market design to 1) send the right investment signals to deploy the needed wind volumes 2) guarantee energy security 3) ensure a cost-effective management of a fully decarbonised energy system.

In parallel a high-level political debate on how to reduce the impact of high energy prices on consumers is ongoing. While the recommended measures aim to also address these concerns, this paper focuses on its initial objective that had been decided just before the energy price surge in 2021 and that was WindEurope's position on electricity market design improvements to ensure the necessary investment trajectory towards climate neutrality.

Europe recently agreed a significant reform of its Energy Market Design with the 'Clean Energy for All Europeans' package. It must build on this reform rather than enact radical changes in response to the current crisis that would have lasting negative consequences for the transition to climate neutrality. Short-term wholesale markets (based on the marginal cost approach) are very efficient in reflecting the real value of electricity at any given time. The marginal pricing mechanism must be maintained.

As it transitions to an energy system with very high shares of variable renewables, Europe must adapt its energy market design to address the following challenges:

- Short term wholesale market signals are not sufficient on their own to drive investments in new renewable power generation capacity in the volumes needed to deliver climate neutrality
- High price uncertainty in the long term is not viable for consumers, generation asset developers and investors alike and it increases the financial risk and costs of investments in new power capacity
- Incentives for building new flexible capacity or flexibility capabilities in new and existing assets, including renewables, are inefficient or missing

To deliver a climate neutral and energy secure system, Europe market design must;

- ➢ **Ensure efficient dispatch**: Short-term wholesale markets need to evolve but they should remain the main mechanism for ensuring cost efficient power plant dispatch and settlement of electricity market contracts;
- ➢ **Unlock investments in new capacity**: Long-term contracts (2-sided Contracts for Difference, Power Purchase Agreements, "10 year plus" futures traded on stock exchanges etc.) will help unlock the investments needed to accelerate renewables deployment. Long-term contracts provide energy consumers, asset developers and investors certainty and reduce the impact of short-term fluctuations in prices. Next to auctions, Governments should enable market-driven projects.
- ➢ **Accelerate grid buildout**: System operators, renewable asset developers, technology suppliers and end-users need deeper cooperation since the early design stages to accelerate grid development and optimisation and to create locational investment signals.
- ➢ **Make the best use of the grid**: to alleviate grid scarcity and structural congestion and to create flexible capacity, we will need limited centralised or regional auctions for renewables co-located with storage (short- and long-term) alongside accelerated grid build-out and optimisation.
- ➢ **Ensure energy security**: Long-term adequacy mechanisms (Capacity Remuneration Mechanisms) should be fully consistent with the delivery of climate neutrality. They should only be deployed in countries that temporarily need them for security of supply. They should meet an emissions performance standard starting from the European Investment Bank (EIB) lending policy standard and decreasing over time. They should be limited to providing the required adequacy and designed to minimise distortive impacts on energy markets;
- ➢ **Drive energy system integration**: The design and implementation of balancing markets, including cross-border trading, but also of 2-sided CfDs must be improved to incentivise a more market- and system-responsive operation of wind farms; and
- ➢ **Reward flexibility**: Ancillary services must be designed providing long-term visibility and harmonisation to drive investments in new flexible resources.

1 MARKET DESIGN UNDER THE SPOTLIGHT

1.1 Focus of this paper

The objective of this paper is to recommend a set of market design measures that we consider necessary for supporting the investment trajectory towards the renewables-based electrification. Notably our focus is on measures that can reply to the following three questions:

1) How should short-term wholesale energy markets evolve and be complemented to drive investments in new wind capacity?
2) Which additional mechanisms will be necessary to drive investments in flexible assets and adequacy reserves necessary for energy security?
3) Which design of market mechanisms or other drivers should be deployed to incentivise wind farm developers to invest in flexibility capabilities and wind farm operation to become more system-responsive?

1.2 The context in Europe

Europe has formally committed to accelerate towards a fully decarbonised economy and to become the first climate neutral continent by 2050. The most effective way to get there, according to the European Commission (EC), the International Energy Agency (IEA) and many other organisations, is through the renewables-based electrification of the economy.

The enabling technologies that will deliver this are available today or already in an advanced development stage[1,2]. However, markets must be adapted to ensure that the right signals to scale up all necessary investments for the net-zero deployment are provided.

Figure 1 summarises the inefficiencies of the current electricity market design in driving investments for new power capacity, new adequacy reserves and flexibility resources. These regard not only the expansion of wind energy but also of other resources that will be necessary in the transition towards climate neutrality. The following paragraphs explain how these inefficiencies can slow down the renewables-based electrification of Europe.

[1] In this paper the term "enabling technologies" is used to refer to renewable generation assets, cross-border interconnections, renewable hydrogen production, battery storage including electric vehicle charging infrastructure, demand-response, hydropower and pumped hydro-electric storage and limited types of low carbon dispatchable generation.

[2] ETIPWind, WindEurope, "Getting fit for 55 and set for 2050", June 2021.

Figure 1 Major inefficiencies of the current electricity market design

1. Short-term wholesale markets are very efficient in reflecting the real value of electricity and to secure cost-efficient generation dispatch at any given time but they are not sufficient alone to drive investments in new power capacity
2. High price uncertainty in the long-term is not viable for consumers, generation asset developers and investors alike and it increases the financial risk and cost of investments in new power capacity
3. Incentives for building new flexible capacity or flexibility capabilities in new and existing assets, including wind farms, need to be reinforced

1.2.1 Short-term wholesale markets and investments in new power capacity

Price formation in short-term wholesale markets based on the merit order model and the marginal cost approach (in day-ahead markets) or pay-as-bid (in intra-day markets) is the best mechanism to ensure a cost-effective dispatch of the available generation resources and to incentivise flexible behaviour by the various assets. These markets are very efficient in reflecting the real value of electricity at any given time.

The "Clean Energy for All Europeans" package (CEP) has very much focused on optimising short-term wholesale market signals and dispatch. As it stands several improvements are still necessary in the implementation of the CEP concepts across Europe. Nevertheless, in the next decades we see short-term wholesale markets remaining the main mechanism for electricity price formation and to secure cost-efficient power plant dispatch.

However, to ensure affordable energy for all consumers, it is crucial to accelerate the clean energy transition by ensuring investments in new renewable power capacity and flexibility solutions both on supply and demand side. Most zero-carbon technologies- such as wind or solar PV, have low marginal costs but require important upfront capital investment. The increasing share of low marginal cost technologies, like wind and solar, in the generation mix of a bidding zone, leads to a declining trend of their wholesale prices which in turn contributes to reducing retail prices. Though current electricity price levels are at record levels due to the geopolitical situation, the downward trend is expected to resume once the fossil-fuel price increases subside.

The long-term trend of decreasing wholesale prices thanks to the increasing market shares of wind and solar is positive for the consumers (as lower wholesale prices will be priced into retail contracts). But naturally this trend will be reducing revenues from the short-term wholesale markets for all generators and will be an issue for paying off investments and fixed costs in all types of new power capacity.

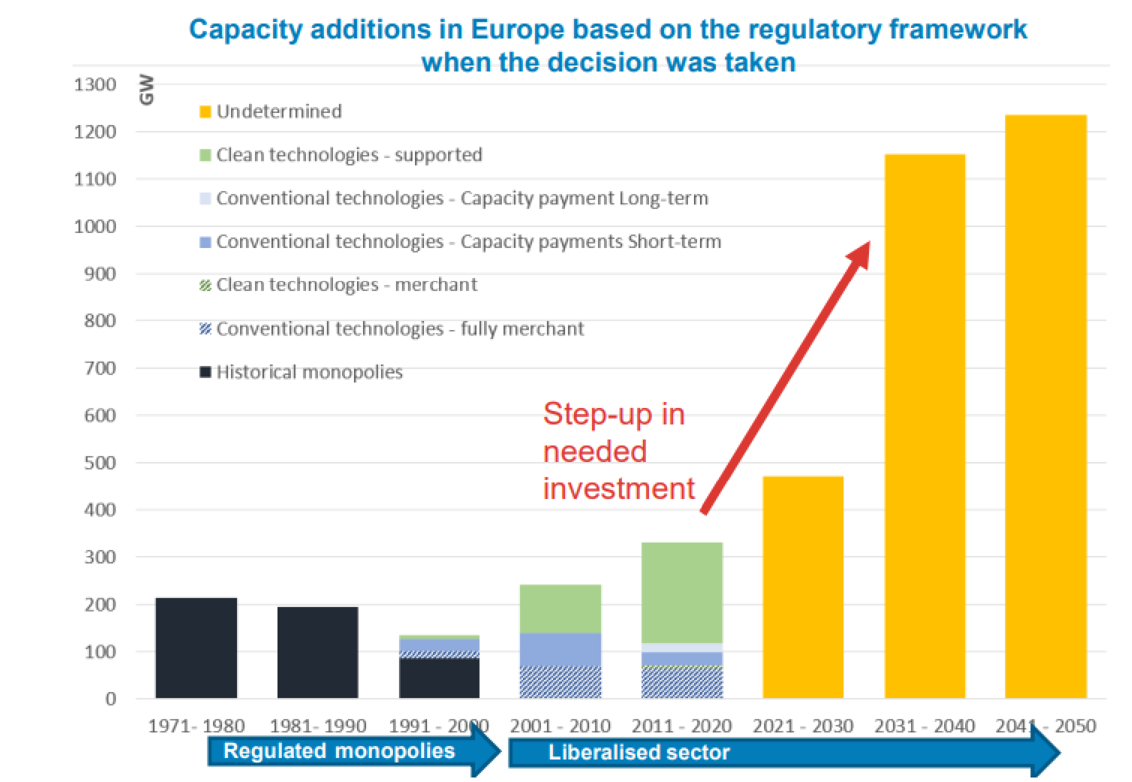
In general generation asset developers will only be able to finance investments with revenues from day-ahead and intra-day markets if the market clearing price will remain significantly above the marginal costs of their assets for a significant number of hours each year over the lifetime of a project. For peak power plants, running only a few hours a year, prices will need to be significantly higher than their marginal cost to be able to retain economic viability. But also renewable power producers with a large number of full-load hours risk to face the "missing money" problem. The similar generation profiles and low marginal costs of their power plants will be pressing prices down during high wind or solar PV energy infeed times. Flexible end-user demand and storage assets might be able to capture (and deliver to end-users) this low-cost electricity. This can also help stabilising prices at a sustainable level for generation asset developers but it can only happen if Governments provide the right signals for capital investments in such flexible technologies.

Considering the above trend and the high upfront investment needs in wind and solar, revenues from short-term wholesale electricity markets (including scarcity pricing) alone will in several cases not be sufficient to attract long-term investments in new power capacity and in new renewable technology development (e.g. advanced wind turbine types).

The investment trajectory in power capacity additions in Europe since the 1970s, illustrated in **Figure 2**, reinforces this argument. Since 1971 most investments in additional power capacity in Europe – thermal and renewable– have been made under regulation or supported by long-term contracts.

Moving forward complementary measures to short-term markets such as contracts for long-term price stabilisation that factor in the price fluctuation in wholesale markets (2-sided Contracts for Difference, Power Purchase Agreements, hedging on forward markets) will continue to be necessary.

Figure 2 Capacity additions in Europe based on the regulatory framework when the decision was taken. Source: COMPASS LEXECON[3]



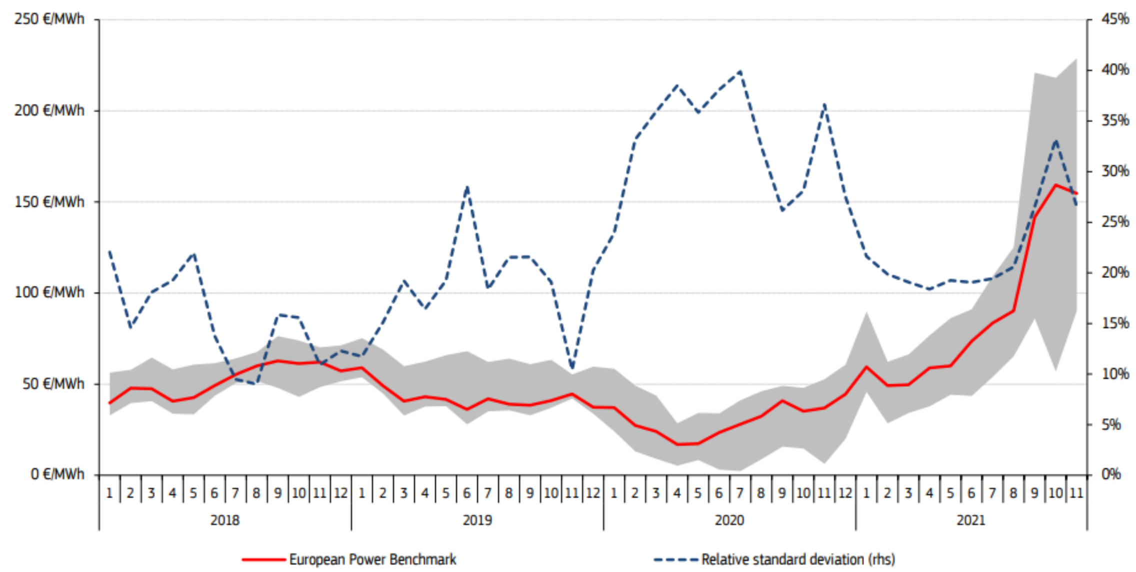
[3] Fabien Roques, Reforming power markets for the energy transition, Stakeholder Workshop on the ACER Assessment on Electricity Market Design, February 2022

1.2.2 Electricity price uncertainty

Price volatility in short-term wholesale markets is very efficient for the cost-effective dispatching of available energy resources. However, a continuous fluctuation between price spikes and negative prices combined with limited visibility and control on how often such spikes will occur brings huge uncertainty. This uncertainty is not viable for consumers with inflexible demand and is unfavourable for attracting investments in generation with low-marginal costs and high upfront capital needs.

The steep increase of wholesale energy prices since the beginning of 2021 (**Figure 3**), an 8 to 10 times increase on 2020 average prices, shows that Europe must urgently address its over-reliance on imported fossil fuels. **A renewables-based energy system requires providing a more economically and environmentally sustainable outlook for consumers by reducing energy dependence on imported fuels and keeping energy system costs at affordable levels while enhancing energy security.**

Figure 3 The evolution of the lowest and the highest regional wholesale electricity prices in nine European DA markets and the relative standard deviation of the regional prices. Source: Platts[4]



The current high gas and electricity prices impact most European countries, albeit at varying degrees and timescales. The electricity price component in retail bills typically represents a third of retail prices, the remaining being taxes, levies and network charges. The impact of increased wholesale prices on retail bills depends on how close these prices are tied in each country, the timing of price pass-throughs as well as on potential regulation of retail prices[5]. As it stands, Governments are taking targeted short-term measures to alleviate the burden of high energy prices on energy poor and lower-income households as proposed in the European Commission toolbox[6] and the 'REPowerEU" plan[7].

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[4] European Commission, Quarterly report on European electricity markets, Issue 3 covering third quarter of 2021, 2022

[5] Household prices increased less than 10% in half of the European capitals between January and December 2021 even though in certain cases the initial prices were already high compared to the average (Berlin, Luxembourg, Lisbon). In other locations increases reached 70-80% (Athens, Brussels, Bucharest) or even 144% at Copenhagen. Source: ACER, Update on Europe's high energy prices and ACER's forthcoming assessment of the current EU electricity market design, Informal Ministerial meeting, January 2022

[6] European Commission, Tackling rising energy prices: a toolbox for action and support, October 2021

[7] European Commission, REPowerEU: Joint European Action for more affordable, secure and sustainable energy, March 2022

The cost of electricity is driven by many factors that are not inherent to the design of short-term wholesale markets. These include: the pace of electrification of flexible demand, the resources dispatched to cover the residual load in each zone and thus to clear the market price, the evolution of carbon, coal and gas prices and the dependence of countries and Europe overall on these resources. A well-designed balancing and ancillary services market can help to mitigate such factors and the uncertainty they create but this market will not appear overnight and will be insufficient in many cases.

Furthermore, electricity prices and their uncertainty is driven by many other factors unrelated to energy reserves: taxes and levies, the pace of development of the power grid, power system integration and operation costs (e.g. congestion management, balancing), external shocks, extreme weather events and by market reform decisions.

A longstanding cost driver for electricity is the slow pace of grid development and the inadequate incentives for building flexibility capabilities in existing assets or completely new flexible assets. If grid build-out and the deployment of flexibility resources do not keep up with the pace of renewables-based electrification and the deployment of renewables, redispatch and balancing costs will increase steeply for System operators[8]. This will increase the transmission and distribution fees integrated in end-users' electricity tariffs. **Figure 4** shows the evolution of redispatch and renewables' curtailment costs in Germany between 2013 and 2019 mainly driven by insufficient grid capacity to accommodate power flows.

Figure 4 Redispatch and renewables' curtailment measures and costs in Germany between 2013 and 2020. Source: Ampacimon based on Bundesnetz Agentur data

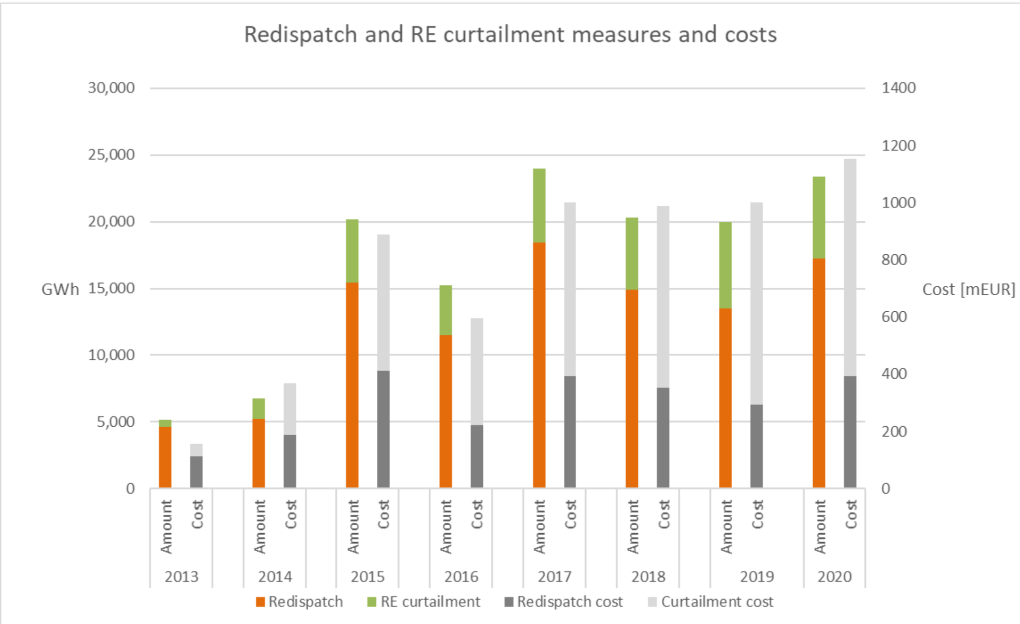


Figure 5 shows the number of negative hourly wholesale prices on selected Day Ahead trading platforms between 2018 and 2021[9]. The total number of hours with negative prices has significantly increased between 2018 and 2020 and remained quite high throughout 2021 (higher than in 2019 for instance) regardless the steep increase of wholesale electricity prices during many of the hours. This is often the result of keeping

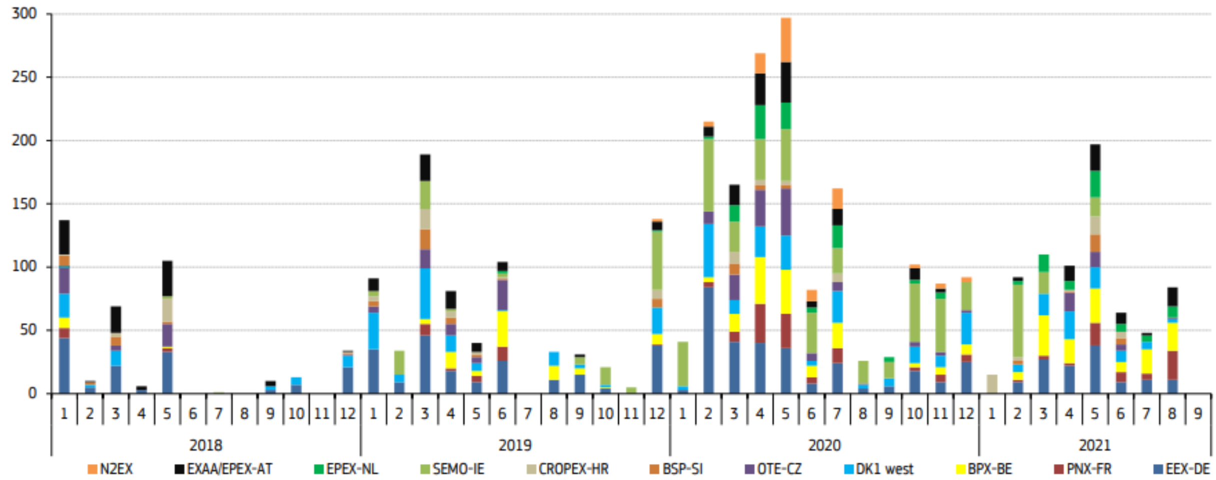
[8] WindEurope, Renewables system integration – a wide approach to cost and value, December 2018

[9] European Commission, Quarterly report on European electricity markets, Issue 3 covering third quarter of 2021, 2022

inflexible conventional generation (e.g. nuclear, lignite, combined heat and power) in operation at times that variable renewable generation is abundant to avoid the costly and high-maintenance operation of restarting the facility for entering the market again or due to heat delivery obligations.

Such factors can heavily affect the uptake of generated renewable power by the system. This translates into higher financial risk for investments in new renewable capacity that also leads to higher finance costs and higher electricity costs for consumers.

Figure 5 Number of negative hourly wholesale prices on selected DA trading platforms. Source: Platts, ENTSO-E[8]



1.2.3 Incentives for flexibility

Phasing out conventional thermal generation will make the matching of power demand and supply at all different timeframes much more challenging than it is today. The need for flexibility will grow exponentially. This will naturally maximise the market exposure of all assets and will put focus on the need for a well-designed and functioning balancing and ancillary services market.

Today flexible thermal and hydro power plants and, to some extent, regional transmission grids, are the main sources of flexibility. New non-fossil fired assets and technologies such as short- and long-term storage, renewable hydrogen, grid optimisation technologies, demand response and cross-border transmission will be gradually taking over this role.

Given the expected shares of variable renewable generation, wind and solar assets - standalone, physically combined, with or without storage, virtually aggregated in generation and demand response portfolios - will also play an important role in flexibility and become more system-responsive.

Short-term market signals can help in incentivising flexible behaviour (e.g. balancing market pricing, peak-shaving) even though there is room for improvement in their current deployment to increase the access to variable renewables. However, these will not be sufficient to drive all necessary capital investments in flexibility capabilities and new flexible resources. Capital investments to build flexibility capabilities in existing assets or to install new flexible assets e.g. storage, renewable hydrogen, combined renewable power plants, or demand side management will only take place if the right long-term investment incentives are in place.

In the case of wind energy, certain market options in the current setup do not adequately incentivise wind farms to combine a more system-responsive operation with the commitment to maximise the renewable electricity dispatch. The “produce and forget” approach does not contribute to harvesting the full flexibility potential of the system and will not be sustainable while we will be transitioning to a fully decarbonised system.

To unplug this mindset, we will need long-term visibility in system needs, even if based on continuously improving estimations, proper definitions of the different flexibility services and transparency on the respective remuneration framework.

2 DRIVING INVESTMENTS TOWARDS NET-ZERO

Delivering on Europe’s decarbonisation targets requires a massive scale-up of variable renewable energy capacity. Short-term wholesale electricity markets based on the merit order model and the marginal cost principle should remain in place to secure cost-efficient power plant dispatch and settlement of electricity market contracts. They are very efficient in reflecting the real value of electricity at any given time and incentivising a flexible behaviour by all market participants. However, they are not sufficient on their own to drive investments in new power capacity in particular wind and solar that have high upfront capital needs.

To mitigate drivers of price uncertainty, the role of long-term contracts will certainly need to be reinforced. Governments will need to carefully assess and decide which are the best price hedging or stabilisation options for investments in new power capacity, adequacy and flexibility in function of their market specifics (Contracts for Difference, Power Purchase Agreements, long-term forward contracts for generation, adequacy mechanisms, ancillary service contracts). Different combinations of such long-term contracts will most probably need to be deployed in each case.

2.1 Investments in wind energy

Fossil-fuel generation is OPEX-based via short-run marginal costs directly linked to fuel prices. Wind and solar are CAPEX-based and operate with low marginal costs. The latter makes their future revenue predictability crucial for reducing investment uncertainty thus their finance cost.

In theory, power supply and demand will match in the long run at all time frames. If day-ahead prices become too low, flexible demand resources and storage will take advantage of this and contribute to setting the prices at higher levels. This can indeed contribute to securing revenues and investments in wind energy in the long term.

However, in practice, there is a mismatch between renewables deployment and the electrification of demand. While Governments play an important role in mitigating this, neither the ambition of Member States nor public opposition is the source of this mismatch. A major factor is permitting rules and procedures for renewable energy projects which are too lengthy and inefficient in most Member States. This results in a market for wind turbines less than half of what it should be which is a huge struggle for the wind supply chain.

Another major issue is that the wind industry must grapple with high steel and commodity prices, disrupted supply chain and uncoordinated trade defence measures[10].

Due to the urgency of building out wind at scale, we need a market design that offers several options at the same time. Long-term commitments are crucial to boost the EU wind manufacturing, technology development and innovation. To achieve this, the revenues for asset developers from short-term markets will need to be supported by long-term contracts such as Power Purchase Agreements (PPA) or state-backed 2-sided Contracts for Difference (CfDs) that reduce price uncertainty for consumers, asset developers and investors. Still the captured price in day-ahead and intra-day markets should be driving the reference price in any deployed long-term contracts.

The following paragraphs give an overview of the different market options that exist today for driving investments in new wind capacity and specific recommendations on how to improve these options to accelerate on the necessary investment trajectory.

2.1.1 Day-ahead and intra-day markets

Day-ahead and intra-day markets play a major role in setting the electricity price. On the implementation side, a set-up that combines a day-ahead market with maximum 15-minute auctions and a continuous intra-day market (and cross-border trading) is the best trade-off to ensure market liquidity and to facilitate the trading of renewable electricity.

The day-ahead market should be setting the baseline and the continuous intra-day market with a gate closure time as close to delivery as possible should be enabling all necessary real-time adjustments. This allows market players to use the best available generation and consumption forecasts so that they can generate and submit to the System operator accurate and well-balanced schedules.

In some markets a small number of intra-day auctions might also be helpful to increase price transparency. Moreover, the scope of day-ahead and intra-day markets should also be expanded to include demand response not only via aggregators but also directly by large and medium end consumers.

2.1.2 Two-sided Contracts for Difference

As it stands investors in renewables have two best options for ensuring stable revenues and minimising finance and project costs: long-revenue stabilisation mechanisms such as CfDs and PPAs.

Between these two and considering various CfD designs (2-sided CfD, sliding premium, fixed premium, …), the 2-sided CfD is the cheapest investment de-risking option from the consumer perspective. Today such contracts are awarded via competitive auctions organised at national level by Governments so that they can fulfil their renewables targets in compliance with their National Energy and Climate Plans (NECPs)[11].

Even though recent cost reductions have raised the prospect of subsidy-free development in some markets, wind energy remains an industry with ongoing technology development needs and supply chain challenges. Certain national electricity markets might provide diverse opportunities to wind farms to stack revenues in the long-term (for instance on the back of flexibility markets) and might, in certain cases, eventually replace

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[10] WindEurope letter to the Commission, European wind energy supply chain struggling, Green Deal at risk, February 2022

[11] ref. WindEurope paper on non-price criteria in auctions

fully State-backed price hedging. **However, in most cases the 2-sided CfDs must remain an option as an effective mechanism which developers could opt for to stabilise revenues**.

With increasing volumes in long-term future markets, investment into new generation could increasingly become offtaker financed, perhaps via the intermediary of aggregators. In some cases, the design of these contracts might evolve to include private price hedging and minimise the price hedging component that is today State backed (for instance it could be limited to each Member State's credit default risk).

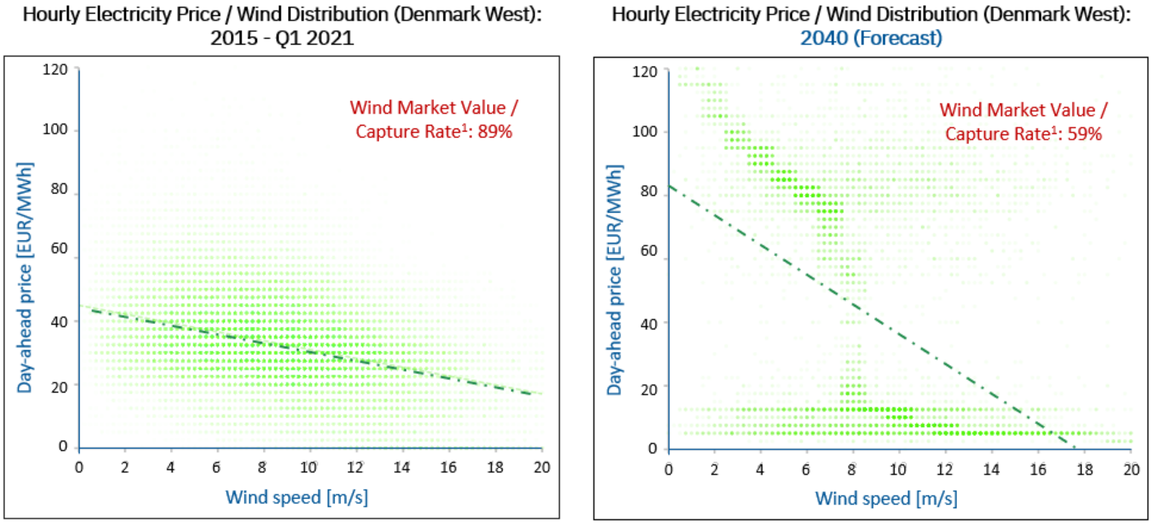
However, such design would require further reflection considering various factors such as the credit rating of each Member State, the potential complexity that it could add to the process, the impact on strike prices and finance cost for asset developers and the pressure it can put on the wind supply chain to further reduce costs.

On the implementation side, today national Governments award 2-sided CfDs in the competitive auctions and they offer wind farms a fixed strike price for the electricity they produce. Once the wind farm is operational, when the price it captures (in the established day-ahead and intra-day markets) is higher than the strike price, the wind farm pays the government the difference. When the capture price is lower than the strike price, the Government pays the difference to the wind farm.

While a driving factor for the current inflation uptake, capture prices exceeding reference prices in 2-sided CfDs reduce the renewable energy surcharge for consumers in the long term. Once the fossil-fuel price rally subsides, capture price levels will decrease substantially. If the capture price declines significantly over a project's lifetime, e.g. due to slow electrification or lengthy permitting procedures, Governments will most of the time need to top up the captured market price to ensure stable revenue (with respect to the fixed strike price) and investment pay off.

As discussed in Chapter 1, the value factor of wind and solar decreases as their market share increases. **Figure 6** shows an estimation of the distribution of hourly electricity prices in relation to the wind speed between 2015 – Q1 2021 (based on Nordpool data) and in 2040 (forecast) in the Danish bidding zone DK1. Based on most market forecasts, the percentage of the average price captured by wind is expected to reduce significantly over the next decades. High hourly prices will mostly occur during low wind periods and will remain at very low levels, on average, during the rest of time. A speedy electrification, both direct and indirect, is the best solution to capture high wind periods and stabilise electricity prices.

Figure 6 Hourly electricity price distribution in the Danish bidding zone DK1 in relation to the wind speed between 2015 – Q1 2021 (based on Nordpool data) and in 2040 (forecast) Source: Nash*Renewables



¹ Capture rate: Percentage of the average market price captured by an onshore wind asset

Source: NASH*Renewables based on Nordpool data for 2015 – Q1 2021

2.1.2.1 Designing Contracts-for-Difference to support energy system integration

The choice of the reference price in the 2-sided CfDs is key. Reference price is the market price that is considered to estimate the capture price by the wind farm and the resulting 2-sided CfD payments. The reference capture price can be the hourly wholesale price, the monthly average wholesale price in the specific bidding zone, the monthly average wholesale price captured by wind generation in the specific bidding zone (wind-weighted monthly average) or other options. An hourly reference price will maximise the State backed top-ups. But it will also incentivise wind farms to maximise their output to the grid regardless of the actual power demand in the market.

Today the market design needs to cope with oversupply by a diverse portfolio of generation resources which makes the sorting out quite straightforward. For instance, in case of negative pricing, several markets compensate variable renewables for their expected revenue loss. In the transition towards a net-zero energy system, hours with renewable power oversupply may become more frequent (Ireland is already an example[12]) and require efficient remedial actions, e.g. market-based mechanisms to cope with redispatch.

An effective solution for making wind farms more responsible to market signals and system needs could be 2-sided CfDs using the wind-weighted monthly (or weekly) average wholesale price as a reference - (calculated based on real wind generation over the reference period). This would allow 2-sided CfDs to remain bankable and ensure cheap financing but at the same time incentivise wind farms to be more market responsive in the day-ahead market and more active in parallel markets (intra-day, balancing, non-frequency ancillary services).

2.1.3 Power Purchase Agreements

The second option is merchant renewable projects supported by corporate PPAs for long-term price hedging. The corporate PPA market grew by over 55% in 2021, from a cumulative capacity of around 12 GW at the end

[12] Ireland has stopped compensating wind farm owners since 2018 every time non-synchronous generation reaches 60% of the generation mix

of 2020 to over 18.5 GW by the end of 2021. Wind energy makes up at least two thirds of all contracted capacity in PPAs. **Figure 7** shows the annual contracted PPA volumes in Europe since 2013. Certain countries are far more advanced than others in enabling the growth of the PPA market for renewables. **Figure 8** shows the breakdown of cumulative contracted PPA volumes by technology in some EU countries.

Figure 7 Annual contracted Power Purchase Agreements in Europe Source: WindEurope

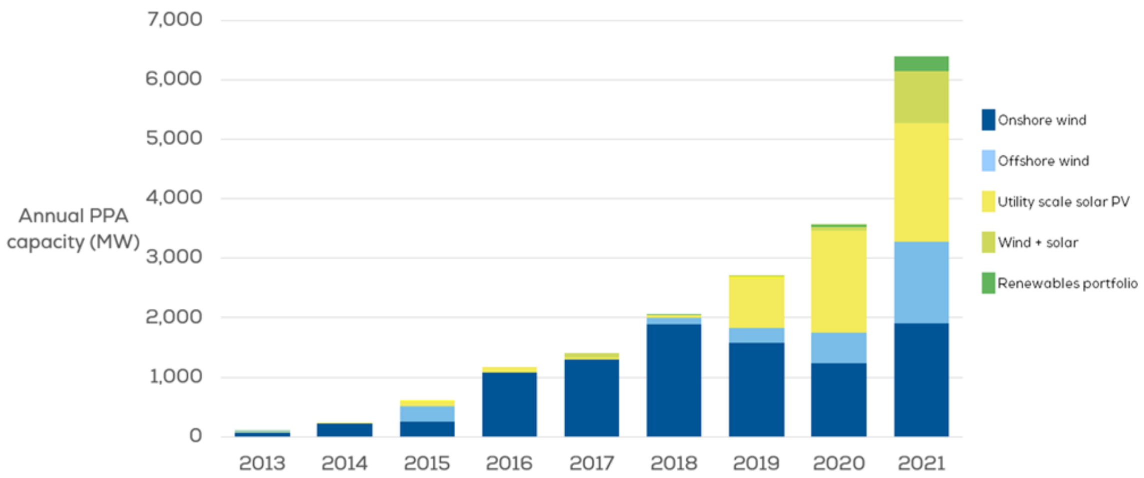
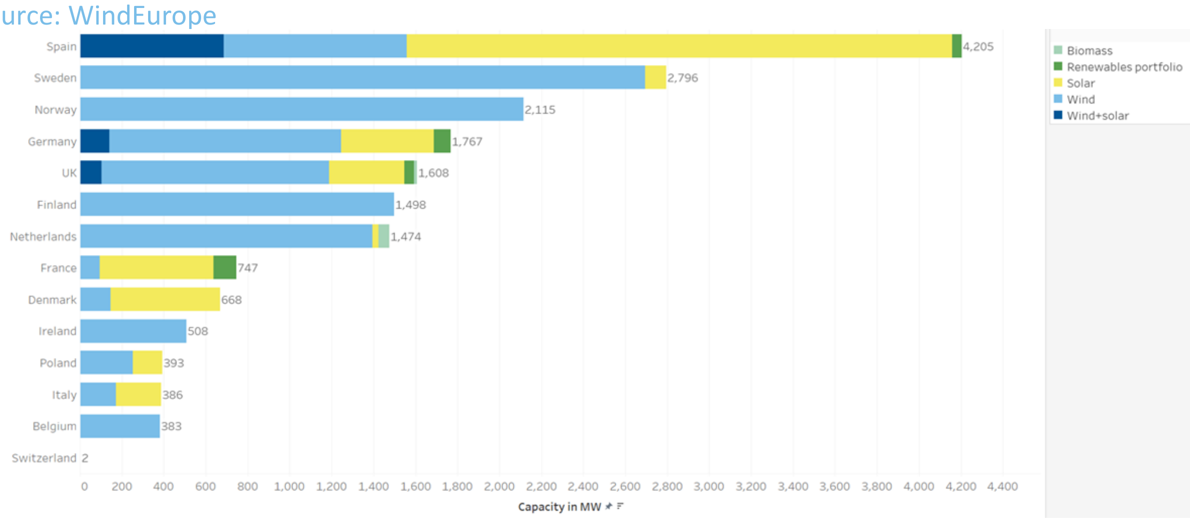


Figure 8 Breakdown of cumulative contracted PPA volumes by technology in different EU countries Source: WindEurope



To enable further growth, Governments can take action to improve market drivers. Administrative and regulatory barriers to the development of corporate renewable PPAs should be simplified and removed. Corporate buyers and sellers should have better safeguards for the implementation of renewable energy PPAs. On the other hand, Governments should also simplify and speed up the permitting processes. A short and simple permitting process is key to unlock the potential of corporate renewable PPAs.

Moreover, Governments must be able to experiment combinations of different options and different models that can be applied to the same project. For instance, renewable generation developers should have the option to use part of an asset's capacity (or generation) to meet the demand of an offtaker under a PPA and to bid the remaining capacity (or generation) into a national auction and receive state aid (partly merchant projects).

Developers being able to combine corporate renewable PPAs and revenue stabilisation allocated in a government-run auction accelerate the pace of decarbonisation. This optionality makes better sense for onshore wind projects, because the typical lead time of about 3 years between bid award and their commissioning date can allow for a harmonization of the PPA sourcing and bid submission process. For offshore wind projects with lead times of 4-6 years such a harmonization is difficult if not impossible.

To this end, renewables should in principle receive Guarantees of Origin (GOs) for the totality of their production, for traceability reasons. Where renewable generation receives state aid, Member States may want to retain the right to cancel the related GOs on behalf of the generator, or to sell the related GOs in a central auction. But this should be strictly limited to the GOs that represent the renewable electricity which has received public support.

Assets that have taken part in national auctions without having been granted state aid (zero subsidy bids) must be eligible to sign a PPA for their full capacity. The traceability and proof of green credentials of the power supply brought in by GOs underpinned PPA volumes and should be maintained going forward. Member States should implement clear rules to guarantee the traceability, harmonised across the EU and in interconnected third countries that are part of the Continental Synchronous Area.

Merchant projects supported by corporate PPAs should be able to come forward without Governments cashing in concession payments or limiting sites to centralized tenders. Such design does not create value and can slow down the build-out of offshore wind energy. Negative bidding in centralised auctions creates uncertainty around future revenues, increases the financing costs of new wind farms – and crucially adds costs to a project that have to be passed on to consumers and suppliers. Governments should also allocate space, in particular maritime space for offshore wind, for fully merchant projects. Government tenders alone may not be sufficient to meet the steeply increasing industrial demand for large-scale offshore wind development.

Furthermore, an increasing number of companies are setting targets to buy 100% of their electricity from wind and solar sources. Some of these have already met their total electricity consumption with renewables on an average annual basis through a combination of PPAs, on-site generation (behind-the-meter) and unbundled GO purchases.

Some of these companies are now aiming to maximise the impact of their energy procurement strategies on grid decarbonisation by matching their demand with clean electricity supply on at least an hourly basis, 24/7. The potential benefits include increased transparency of corporate sustainability claims and potential granularity of carbon accounting, increased renewable energy investments, new business models and innovative technologies, closer alignment of markets with the physics and economics of the grid and the variability of supply and demand. Several platforms such as the RE-Source platform and the EnergyTag Initiative but also certain TSOs and DSOs have already been working on ways to put such strategies into practice.

2.2 Investments in security of supply

As it stands to ensure security of supply - which includes energy security, adequacy and operational security - most EU countries with rapidly growing market shares of wind and solar combine short-term wholesale markets with a centrally coordinated long-term adequacy mechanism. Such mechanisms can be Capacity Auctions, Strategic Reserves mostly as a temporal solution for mothballing assets outside the market or other similar forward capacity or availability markets. **Figure 9** shows an overview of the different adequacy mechanisms that are currently deployed across European markets.

Until today Capacity Remuneration Mechanisms (CRMs) in Europe have been designed as long-term contracts or subsidies to stabilise revenues for fossil-fuel based generation.

Interestingly, due to the integration of derating factors[13], current CRMs are not suitable for the revenue stabilisation of other assets such as co-located renewables with battery storage, combined renewables (wind and solar assets sharing a common grid connection) with or without storage, standalone battery storage assets, cross-border transmission, aggregated portfolios integrating demand response that can also operate as baseload assets.

Figure 9 CRMs in Europe in 2019. Changes with respect to 2018 are printed in red[14]. Source: ACER and CEER (2020)

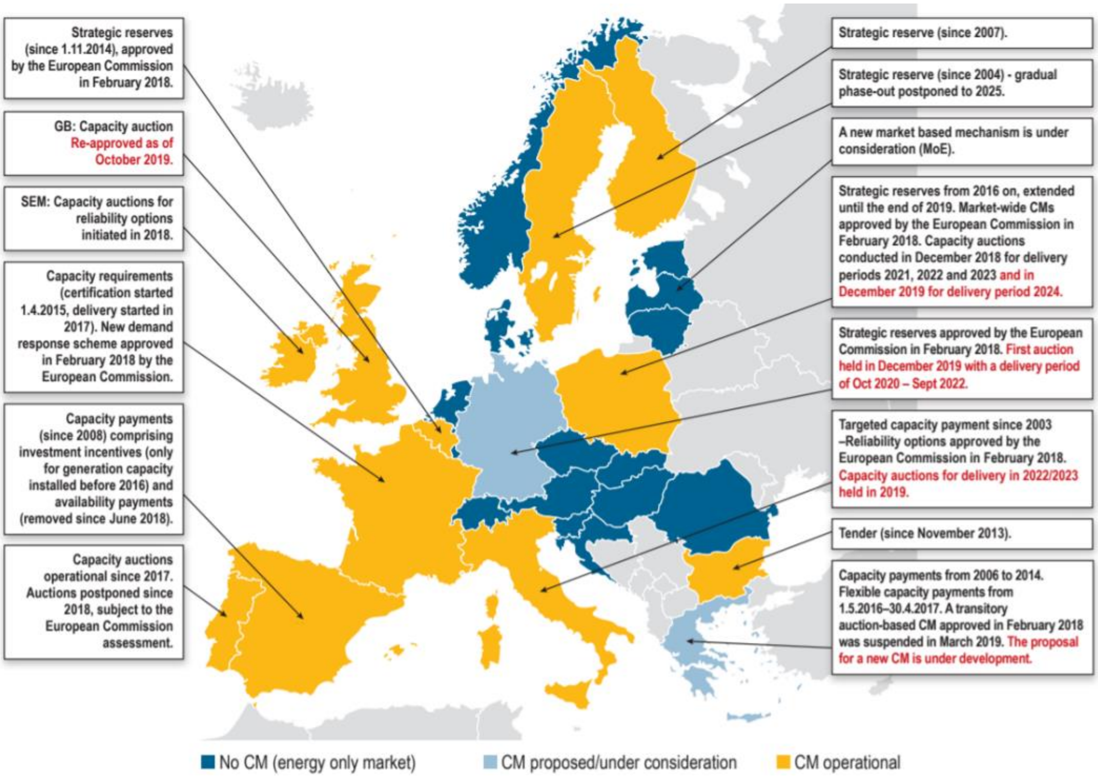


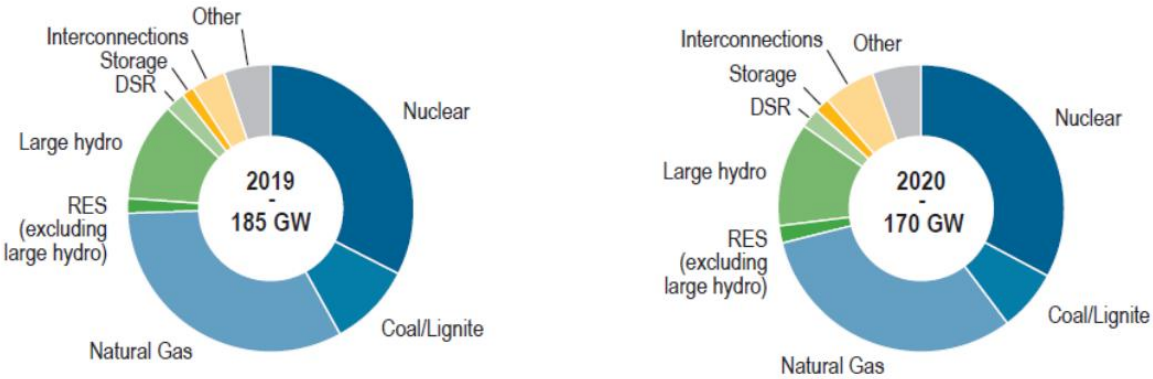
Figure 10 shows that in 2019 and 2020 almost half of the total capacity that was remunerated through CRMs in several EU countries consisted of fossil-fuel based generation (natural gas and coal/lignite), more than one third of nuclear power plants and the rest included storage, demand-side response, renewables, interconnections and large hydro power plants[15].

[13] Derating factors are used to estimate the remuneration on the capacity credit of different assets based on the amount of firm capacity they can provide rather than for their nameplate (or nominal) capacity. Typically these factors are very low for variable renewable generation assets but also for storage assets in many cases.

[14] T. Schittekatte, L. Meeus, Capacity Remuneration Mechanisms in the EU: today, tomorrow, and a look further ahead, Robert Schuman Centre for Advanced Studies Working Paper 2021/71

[15] T. Schittekatte, L. Meeus, Capacity Remuneration Mechanisms in the EU: today, tomorrow, and a look further ahead, Robert Schuman Centre for Advanced Studies Working Paper 2021/71

Figure 10 Capacity remunerated through CRMs in several European countries per type of technology in 2019-2020. Data: Belgium, Bulgaria, France, Finland, Greece, Ireland, Poland, Portugal, Spain, Sweden and Great Britain. Source: ACER and CEER (2020)



Globally there are examples of energy-only markets where energy prices (and their volatility) including scarcity pricing are the only mechanism to attract investments in new capacity e.g. the Australian Energy Market Operator (AEMO). Such examples show that there is significant room for improvement in EU short-term wholesale markets for driving investments in security of supply based on energy-only markets.

However, considering the current low level of EU markets' interconnection in some regions, the rapidly growing volumes of electrified demand and the low reserves of flexible demand, we consider that long-term adequacy mechanisms as CRMs should remain a market option but only with the right “energy transition” design (additionally to the general and design principles set in Regulation (EU) 2019/943, articles 21 and 22). They should be used in European markets that need them to drive investments in new adequacy reserves. This will mostly be the case in countries with big industrial demand, low level of interconnection or quickly phasing out conventional generation such as nuclear or fossil-fuel based generation.

These long-term adequacy mechanisms should provide long-term capacity contracts with short- and long-term storage, demand response, renewables combined with storage, renewable hydrogen and aggregated renewable-based portfolios.

In October 2021 the Belgian TSO Elia organised the first auction of its new technology-neutral CRM with delivery period between 2025 and 2026[16]. The winning bids include 30.48MW of new large-scale battery projects and 10.64MW of new small-scale battery projects most of which were awarded 15-year capacity contracts. They also consist of 287.07MW of existing demand side management projects, 49.82MW of existing aggregated technology projects and 436.6MW of existing Combined Heat and Power projects mostly awarded 1-year contracts.

This is a positive step as it increases the participation of carbon-free technologies in such mechanisms. However still in this case most of the remaining capacity (3.6 GW) has been awarded to Combined Cycle Gas Turbines. 1.9 GW of the total capacity remunerated is existing capacity. The future CRMs need a much more ambitious alignment with the EU net-zero commitment.

The Clean Energy Package introduces a CO_2 emissions performance standard to CRMs. As of July 2025, generation assets that started commercial production before 4 July 2019 and that emit more than

[16] A total of 40 Capacity Market Units (≈ 4.4GW of total capacity) have been awarded a contract with a weighted average bid price of 31672€/MW/year and a highest bid price of 49993€/MW/year.

550gCO2/KWh of electricity and more than 350kgCO2 on average per year per installed kW will be excluded. However, this is not enough to gradually replace most fossil-fuel based assets in Europe giving the opportunity to new technologies to contribute to adequacy.

The new long-term adequacy mechanisms should be fully consistent with the delivery of a zero-emissions European power system. They should apply the following principles:

- Immediately replace the CEP emissions performance standard (maximum 550g CO_2/KWh of electricity) with the one set by the European Investment Bank in its revised energy lending policy in 2019 (250g CO_2/KWh of electricity)
- A gradual decrease of this emissions performance standard with clearly defined milestones to 2035 (considering 15-year CRM contracts, or 2040 considering 10-year standards) to phase out fossil-fuel based generation
- Facilitate the qualification of short- and long-term storage, demand-response, combined renewable power plants with or without storage, renewable-based aggregated portfolios and cross-border capacity according to their ability to contribute to security of supply
- The length of awarded contracts should also be set in function of the emission performance standard of the respective technology

2.3 Grids and locational investment signals

Investments in grid build-out and grid optimisation are crucial for accelerating investments in new power capacity. As it stands, most EU countries are struggling to keep up the pace of necessary grid build-out for achieving Europe's decarbonisation targets. Europe needs to double investments in electricity grids to deliver a climate neutral energy system by 2050[17]. Various factors contribute to this. A major factor is the lack of alignment between the national network development plans (NDPs) and the national targets for renewables-based electrification[18]. This gap is even larger in the case of offshore grid development.

Other important factors are the inadequate coordination between TSOs and DSOs at national level, the low social acceptance of new grid infrastructure but also the missing incentives for TSOs and DSOs to accelerate grid build-out and to invest in grid optimisation[19,20,21]. Europe needs a better governance and holistic planning of the EU energy infrastructure that engages the different sectors (power/gas/renewable hydrogen/heat/mobility) and governments all together. This already comes clear in the 'RePowerEU" plan by the Commission[22] and the "10-Point Plan" recently presented by the International Energy Agency[23].

To address the lack of grid and mitigate structural congestion, the optimised siting of new electrified demand and new renewable capacity will play a major role. The core objective of building transmission and distribution networks is to serve their users. This means that grid users will need to contribute much more than today to

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[17] ETIPWind, WindEurope, "Getting fit for 55 and set for 2050", June 2021
[18] WindEurope, WindEurope response to ENTSO-E Consultation on the TYNDP 2020 "Power system needs in 2030 and 2040" report and accompanying documents, January 2021
[19] WindEurope, Making the most of Europe's grids: Grid optimisation technologies to build a greener Europe, September 2020
[20] ENTSO-E, Why remuneration frameworks need to evolve, April 2021
[21] ACER, Infrastructure efficiency: the role of regulation in incentivising smart investments and enabling the energy transition, November 2021
[22] European Commission, REPowerEU: Joint European Action for more affordable, secure and sustainable energy, March 2022
[23] International Energy Agency, A 10-Point Plan to Reduce the European Union's Reliance on Russian Natural Gas, March 2022.

grid planning and development since the early stage of these processes. This will require dedicated long-term and short-term measures at regional, national and EU level.

2.3.1 Long-term locational investment signals

The potential impact of location of new electrified demand over the coming years needs to be recognised and assessed as soon as possible for designing adapted market signals. This concerns new demand both from direct electrification (e.g., data centres, EV charging, heat pumps) and indirect electrification (e.g., large electrolysers by the industry, decentralised electrolyser for renewable hydrogen refuelling stations).

As it stands in most cases System operators develop the underlying scenarios for grid planning on their own, which are then submitted to consultation by the respective grid users. This process needs to change. Grid users will need to be involved and actively contribute to the development of the underlying scenarios since the early stages.

Dedicated multi-stakeholder groups can be created at regional level (coordinated by the DSOs), at national level (coordinated by the TSOs) but also at European level (for instance for improving the Ten-Year Network Development (TYNDP) process) coordinated by ENTSO-E and the EU DSO Entity. This change of mindset is urgent but will only show its benefits in the long-term.

2.3.2 Medium- and short-term locational signals

System operators regularly deal with the existing grid scarcity and structural congestions by paying a compensation to renewable asset owners for missed revenues due to curtailment (voluntary or as a response to negative prices). This might remove the financial drawbacks for asset owners but this means that the energy system does not benefit from the corresponding zero-carbon generation. Moreover, moving forward, financial compensation will not be straightforward when oversupply of power will be purely renewable.

To reduce the volumes of curtailed renewable energy, Governments can set up limited centralised or regional auctions for renewable assets integrating storage units ("grid integration" renewable capacity auctions) in zones that are identified as congested ("red"). The winning assets should have the option to be awarded 2-sided CfDs that can remunerate both the generation and the storage unit. Existing assets willing to upgrade should also be eligible for such auctions if installed in the respective "red" zones. Such provisions can quite quickly alleviate grid scarcity and structural congestion and can create flexible resources in line with the decarbonisation targets.

The implementation of these mechanisms can be part of a broader plan that also accelerates the build-out of electricity grids which is indispensable to delivering a decarbonised energy system.

Local flexibility markets are often suggested as alternative solutions to mitigate structural congestion in areas with a considerable amount of flexible demand. Opposed to "grid integration" renewable capacity auctions, local flexibility markets are much less helpful for renewable asset developers as the market value of flexibility is not always explicitly attributed to them.

2.3.3 Nodal market pricing concept

To accelerate grid build-out and manage congestion, there is an ongoing discussion about the potential impact of transitioning to a nodal market pricing model in Europe, as the one deployed in the United States. This could be an effective approach for considering locational factors in pricing[24].

However, today most stakeholders in Europe agree that a transition from the current zonal to a nodal market pricing model would be too demanding in terms of resources and administrative costs but also in terms of change management (completely different pricing system than the current zonal one, severe redistribution of revenues and costs). Besides, today this could not be justifiable by the current number of intra-zonal congestion bottlenecks in Europe[25]. It would also increase the financial cost of additional price uncertainty and merchant risk exposure for generation assets.

Considering its potential benefits, the aggregation of flexibility per transmission node could be explored as an alternative. Eventually the deployment of some regional pilot projects could be the way forward.

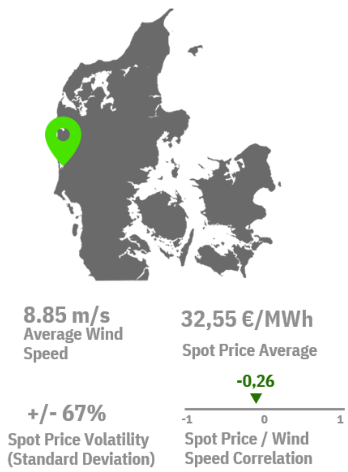
3 FLEXIBILITY MARKET DESIGN

3.1 Investments in flexibility resources

From a market perspective flexibility can be provided in two ways today[26]. The first one is about generation assets and consumers being reactive to price signals in established wholesale markets (day-ahead, intra-day and balancing). This type of flexibility is highlighted by the case study presented in **Figure 11**. It shows the increase in capture price, annual revenue and displacement of carbon displacement that was achieved by operating a wind farm in Denmark for 20 years focusing on market value - responding to market and system signals - rather than maximising power output.

Figure 11 Case study of a wind farm in Denmark operated to maximise its capture value from short-term wholesale markets instead of maximising its power output Source: NASH*Renewables

	Conventional Choice	**NASH*CHOICE**
Turbine Class	IEC IIA (high/medium wind)	IEC IIIA (low/medium wind)
Temporal Resolution	20 x 1 year	
Uptime	98%+	73% (-26%)
AEP (Energy Production)	28,400 MWh	25,900 MWh (-9%)
Capture Price	29.9 €/MWh	35.20 €/MWh **(+17%)**
Annual Revenue, NPV	€ 625K	€ 676K **(+8%)**
Effective Carbon Displacement (annual)	11,000 tCO_2eq	11,700 tCO_2eq **(+6%)**



Reference case based on 20 years operations target and Nordpool wind market value data for 2015 – Q1 2021

© NASH*RENEWABLES 2022

[24] Regulatory Assistance Project, Clean, affordable, and reliable: getting Spain's power system transformation right, July 2020
[25] ENTSO-E, 2030 Market Design - Stakeholder webinar presentation and discussion of public consultation results, June 2021
[26] This chapter does not address flexibility services that are currently not deployed in the EU context. There are additional flexibility services that can be deployed in a "smart grid" context in the future but these are not discussed here.

The second type of flexibility is about all types of grid-connected assets e.g. generation, demand, storage, providing standardised contracted ancillary services to System operators for resolving common technical operation issues.

Ideally both types of flexibility should be provided by a diverse portfolio of available technologies (generation, storage, grid technologies, demand) including legacy and new assets. To achieve this the market design should not only incentivise assets to assume a flexible behaviour (for instance through negative pricing or high imbalance costs) but it should also incentivise long-term investments in capabilities that can make these assets responsive to flexibility needs. Not all existing assets have such capabilities already integrated. Developers of new assets should have the right incentives to price in such investments since the early design phase of the assets as this will require additional technology costs. This is even more important in the case of wind and solar which require high upfront capital investments.

The two following paragraphs provide recommendations for improving balancing markets and ancillary services across Europe and the participation of renewables in both.

3.2 Balancing markets

The discussion at European level for the development and implementation of the EU Balancing Guideline and the EU balancing platforms has certainly helped to identify market design gaps at national level and to set an action plan. Regarding the procurement of balancing energy, some countries have already made decisive steps and are mature enough to benefit from the implementation of the European balancing platforms. Others are still very immature. The CEP also addresses the procurement of balancing capacity which has not advanced adequately in most of the countries until today.

The pace of implementation varies among countries. In addition, we see large diversification in the design of balancing products but also specific elements in their design that are prohibiting the wide participation of a diversified portfolio of resources. Removing these two major barriers with the right timeline will be key to untapping the full potential of flexibility in the system.

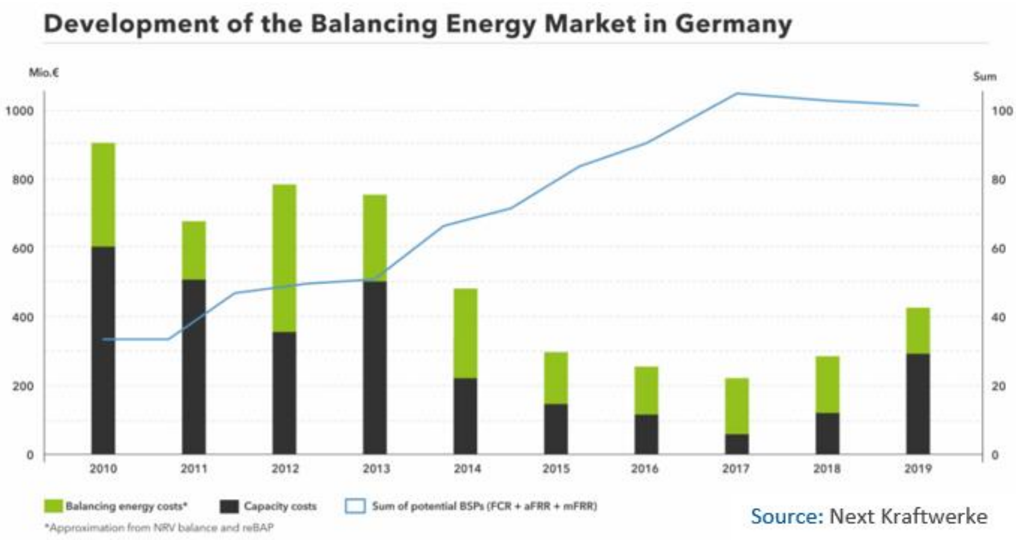
Particularly the participation of variable renewables in balancing markets remains a future target in most European markets, even mature ones, and often currently deployed only with sparse pilot projects. Remarkably, countries that have already allowed renewables or aggregators to provide services such as manual Frequency Restoration Reserve (mFRR) and manual Frequency Restoration Reserve (aFRR) already see a drop in system balancing costs (**Figure 12**)[27].

Regarding the design of balancing products, a set of elements need to be improved. A major milestone in achieving participation of variable renewables in balancing markets is the drop of the minimum size of bids required to participate in the auctions (e.g., 5 MW in Germany for aFRR and mFRR, 25MW in UK for aFRR, 20 MW in PT for aFRR).

In certain countries variable renewables are not even granted access to some balancing products (e.g. aFRR in Poland) or the imbalance cost might be prohibitive (e.g., balancing costs in Romania account for a cost equivalent to 20% of potential market revenues).

Figure 12 Development of the balancing energy market in Germany[27] Source: Next Kraftwerke

[27] Next Kraftwerke, "What is mFRR (manual Frequency Restoration Reserve / R3)?", 2021.



Source: Next Kraftwerke

In some countries TSOs require individual three-party contracts (TSO, aggregator, and asset owner) instead of simplifying the process with a single contract between the TSO and the respective aggregator. In other countries the TSO requires control of each power plant (individual set points), instead of allowing Balancing Responsible Parties to optimise their portfolio (e.g., this applies for some existing assets in operation in Portugal).

Another barrier is the need in some national markets to tender for balancing capacity one month or week ahead: due to the variability of wind and solar, day-ahead bidding (or as close to real time as possible) is crucial to making their participation viable as it can ensure accuracy and reduce risk of non-delivery and therefore penalties.

Symmetrical product structure does not allow renewables to provide down and up regulation separately obliging these to provide headroom by reducing their position in the day-ahead market. This incurs foregoing some day-ahead revenue which is today higher than potential revenue from the balancing market.

Some balancing products are mutually exclusive and might constrain renewables operators' ability to participate in parallel power markets. Where technically feasible and meaningful, stacking of revenues from different services should be made possible to decrease revenue uncertainty and increase procurement efficiency.

Generally, an overly demanding administrative process constitutes a big hurdle (pre-/requalification requirements), drives costs up (e.g., investments in hardware) and makes it less attractive to become an active provider of balancing capacity. Moreover, in most national markets prequalification is designed mostly for thermal power plants. In general, harmonising the design of products and prequalification processes across countries is crucial for making participation in balancing markets viable for variable renewables.

Another big barrier in some countries is extremely demanding data communication requirements established by System operators entailing high CAPEX for communication infrastructure in variable renewable assets. Technical aggregation (for sending measurements), together with appropriate commercial aggregation (for compensating imbalances among units) can be an adequate solution.

Finally, an issue often underlined as a barrier by System operators is the distortive effect of countries financially supporting renewables by toping up their market value with a premium per generated kWh. By design many of these schemes incentivise renewables to produce at maximum output at any given time to obtain the financial support, no matter if the value of their energy is lower in the spot market than in the balancing market. The 2-sided CfDs that use as a reference price the wind weighted average monthly market price can incentivise wind farms to become much more responsive in the balancing markets for generating additional revenues.

Table 1 gives an overview of the deployment of balancing services in seven European countries and the possibility for wind farms to contribute to these.

Table 1 Deployment of balancing services in seven EU countries and the participation of wind energy[28]

Service	DK	DE	ES	GB	IR	IT	NL	NO
Frequency Containment Reserve –					N/A			N/A
Automatic Frequency Restoration Reserve – Energy/Capacity					N/A			N/A
Manual Frequency Restoration Reserve – Energy/Capacity					N/A			
Replacement Reserve – Energy/Capacity		N/A			N/A		N/A	N/A

Service deployed/wind can participate/with remuneration

Service deployed/wind can participate but not economically interesting or under specific

Service deployed/wind can either not participate or is not remunerated

Service not deployed in the country/bidding zone/TSO area

3.3 Ancillary services

The need for ancillary services has grown in recent years in different European markets due to the gradual decommissioning of synchronous generators[29]. New types of services will need to be designed and procured at large volumes addressing all types of assets[30,31].

Table 2 outlines the major ancillary services deployed across Europe today and more that are expected to come. It also shows the possibility for wind farms to participate in these services. Certain National Energy Authorities (NRAs) and System operators have already understood their responsibility in incentivising a diversified mix of resources to provide such services (diversification for driving costs down) but most importantly that this mix should become increasingly low carbon.

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28 Congestion management is not included as a separate ancillary service. In many countries curtailment (active power ramping down) is compensated but not on a market basis so we do not consider this as an "active power ramping" service.

29 WindEurope, WindEurope views on the TSO-DSO coordination: enabling flexibility from distributed wind power, March 2017

30 ENTSO-E Technical Group HPOPEIPS, High Penetration of Power Electronic Interfaced Power Sources and the Potential Contribution of Grid Forming Converters, 2019

31 ENTSO-E Grid Connection EU Stakeholders Committee, Stakeholders' webinar on RoCoF related considerations, 2022

Table 2 Ancillary services currently deployed across EU countries[32]

Service	DK	DE	ES	GB	IR	IT	NL	NO
Fast frequency response	in DK2	N/A		*with FCR			N/A	
Voltage control/steady state reactive power					N/A			
Dynamic reactive response								
Voltage unbalance mitigation					N/A			
Stability services/inertial response		N/A					N/A	
Black start	N/A				N/A			N/A
Active power ramping								
Harmonics damping								N/A
Fast fault current		N/A					N/A	

Service deployed/wind can participate/with remuneration

Service deployed/wind can participate but not economically interesting or under

Service deployed/wind can either not participate or is not remunerated

Service not deployed in the country/bidding zone/TSO area

A recent good example comes from the UK. In 2019 National Grid started tendering services under the Stability Pathfinder programme with the aim to replace the inherent capabilities of conventional dispatchable units (e.g., contribution to inertia, voltage control). In Phase 1 of the programme, the tender was accessible to synchronous compensators and synchronous generators running in a synchronous compensation mode. In these first tenders the range of prices for providing inertia in an annual basis range from 2,500 to almost 10,000 £/year/MVA.s enabling synchronous condensers which are significantly more competitive than the retrofitting of conventional baseload plants – to cover these system needs.

Phase 2 (launched in 2021) is already facilitating a wider range of technology types to participate including battery storage and converter-based technologies[33]. In Great Britain the ancillary services market is growing exponentially with the phase out of coal and the growth of wind and solar.

The UK example proves that such services can be provided by zero emission assets if equal market access is offered to them. If such opportunities are visible and transparent in the long-term technology providers will develop the necessary capabilities and the most cost-effective solutions will manage to provide these services paying off their flexibility investments.

Capital investments will be needed to make sure that assets will encompass technical capabilities for providing ancillary services. And this does not only apply to variable renewables or to new storage installations but to

[32] Congestion management is not included as a separate ancillary service. In many countries curtailment (active power ramping down) is compensated but not on a market basis so we do not consider this as an "active power ramping" service. In this document congestion management is discussed in Chapter 3.3.

[33] National Grid ESO, [NOA Stability Pathfinder – Phase 2 updates](), August 2021

all technologies available in the energy system[34]. Thermal generation units that may remain part of the mix would also need costly upgrades to be able to respond to rapidly ramping up and down needs of a system that is increasingly weather-dependent.

The necessary investments for building such flexibility capabilities in new and existing assets (CAPEX) and for offering the respective services (OPEX, i.e., for power reserve) will be significant in many cases. Both capital and life cycle operational costs must be considered at the early stages of the investment to incentivise OEMS to invest in the respective technology development and asset developers to invest in such capabilities in their assets.

Long-term visibility to potential revenues thanks to the specific capabilities will be vital. Considering these needs, the landscape of remunerated ancillary services in Europe today appears very weak in terms of adequate market signals. To foster long-term flexibility investments we recommend:

1) **Transparency, long-term visibility, and equal asset access to ancillary services markets**: the design of services should not limit to the definition of the technical provision and the remuneration scheme for each product. This is important but only half of the exercise. System operators need to define the system needs and the resulting volumes of ancillary services (with respective metrics per case) and the potential geographical locations where these services will be needed in a 5-to-10-year time horizon.
2) **Clear distinction between required and voluntary capabilities and establishment of remuneration framework, harmonised across EU:** the capabilities provided by a power plant can be classified in 3 types: a) mandatory and non-remunerated (e.g. remaining connected through voltage dips and specific frequency deviations), b) mandatory and remunerated through specific contracts/markets (e.g. frequency sensitive mode), c) voluntary and remunerated through contracts/markets (e.g. black start). These capabilities must be defined and classified under the three categories at European level in the Grid Connection Code. Today, there is big diversity across countries in the definition of capabilities and the interpretation of system needs and possible remuneration.

The demand for ancillary services will grow exponentially in the next years. Even if not possible to define today all the details, an improving estimation on the type and volume of necessary services is urgent and we cannot afford to postpone it.

Many of these system support capabilities (e.g., inertial response, black start…) will not be a system-wide need and should not be a system-wide requirement to avoid stranded investments. Long-term visibility will be vital to ensure market continuity but also to target investments in an optimised number of assets. Some of the needs will be better dealt at grid level by grid optimisation technologies operated by the System operator rather than being applied widely to all generators.

4 OVERVIEW OF RECOMMENDATIONS

To support the necessary investment trajectory towards climate neutrality, maximise Europe's dependence on local energy resources and reduce uncertainty over electricity costs, Europe will not need a revolution but an evolution of its current electricity market design.

[34] This includes generation units with different flexibility capabilities, small- and large-scale storage, demand-response, grid interconnections and coupling with other energy carriers. Source: ETIPWind, WindEurope, "Getting fit for 55 and set for 2050", June 2021, §5.2:Enabling technologies, Figure 33.

It will need to reinforce and improve a set of well-functioning measures already in place and to give an "energy transition" shift to other measures that were not going into the right direction until today. The different countries will need to carefully consider this toolbox and deploy different combinations of the measures depending on their needs. Figure 13 presents an overview of the major measures that go into the right direction for achieving climate neutrality.

Figure 13 Overview of measures that can support the investment trajectory towards climate neutrality