- **Position paper** -

Moving towards full market integration of renewables – the most cost-efficient way to decarbonise the energy sector

Brussels, 20 November 2020 | Significant deployment of renewable energy sources (RES) is required to achieve the EU 2050 net zero target proposed in the Green Deal as well as the raised ambition of the EU 2030 targets. The recently published EU Offshore Renewable Energy Strategy sets out the scale of the challenge, estimating that an installed capacity of at least 300 GW of offshore wind alone will be needed by 2050. Energy markets will be vital to help achieve this scale-up at an acceptable cost. Despite the high fixed cost structure of renewables as well as the need for predictable revenue streams, market-based remuneration of renewables in the energy market offers the most cost-efficient way of achieving decarbonisation. Recent market reforms, including the harnessing of demand-side flexibility, and ensuring RES can achieve revenue streams from multiple markets, need to be fully implemented to allow markets to realise their full potential in a high renewables system.

I. Full integration of renewables in the energy market

Full market integration means that renewables participate in the market under the same conditions as any other (conventional) generation assets and are subject to the same rules. The RES generation remains responsive to market price signals, avoiding the risk of 'produce-and-forget' strategies as well as incentivising further investment in flexibility. It also means that RES generators receive incentives to respond to the needs of the energy grid. Overall, subsidy-free remuneration on the basis of market revenues benefits the end consumer and the energy system as a whole by avoiding costly support payments.

A higher share of renewables in the power system has led to a clear trend of decreasing spot power market prices, due to the low marginal costs of renewables. Even at depressed prices, the day ahead market will continue to deliver an important price signal, incorporating all available information at a certain moment in time, not only generation costs. Other market segments, such as the intraday market, will play an increasingly prominent role in integrating growing volumes of renewable energy. For example, trading is increasingly possible closer to real time, finer product granularities are available and automated trading solutions facilitate RES access to the market. Forward / futures markets provide important tools to hedge and manage price risk through the development of liquidity in contracts with increasingly long time horizons, for example to support the development of PPAs. Moreover, system services that can be provided by renewables (balancing, congestion management and ancillary services) can account for additional revenue streams.

Maximising revenue streams from different markets is an important factor for RES operating under full market conditions. In a high-renewables system, remuneration should originate from market-based revenues. This can be the remuneration of the commodity itself, for example stemming from the exchange price for every MWh produced as well as from the remuneration for the quality of the energy source (via Guarantees of Origin). Therefore, alongside competitive and liquid wholesale markets, a well-functioning emissions market and Guarantees of Origin (GO) market are also needed.

II – RES operation under full market conditions

With an increasing number of RES installations reaching the end of their support time from 2020 onwards[1], many will start operating under full market conditions for the first time. While this brings challenges, such as the exposure to balancing costs or achieving predictable revenue streams, options and strategies are available to ensure that RES installations can operate successfully in the energy market.[2] The following elements provide an important foundation to make these strategies possible.

Box 1: Examples of enabling elements for market-based remuneration of RES

Full participation in all market timeframes to allow 'revenue stacking': RES installations must be able to access multiple revenue streams ('revenue-stack') from different markets. In addition to the wholesale market, the ability for RES to participate in upwards and downwards balancing, provision of ancillary services and market-based redispatch is therefore important. The Clean Energy Package provisions provide the basis for this, and any remaining grid-related and regulatory barriers need to be removed.

Power Purchase Agreements (PPAs): Corporate or utility PPAs provide an attractive route to market because stable agreements can provide developers with longer term financial certainty and businesses/utilities with green energy. Depending on the structure of the PPA, price risk can occur when transactions are made through the spot market. The derivatives market provides the tools to allow market participants to hedge price risks on a long-term basis.

Aggregators and Virtual Power Plants (VPPs): Cloud-based virtual systems pool together distributed energy resources, often including flexible consumers and storage, to optimise production and consumption across the network and enhance access to the different energy markets. These services can help to optimise production profiles and plant dispatch while also contributing to relieving pressure on the grid.

Guarantees of Origin (GOs): Guarantees of Origin (GOs) effectively allow the green value of the energy to be recognised and traded across Europe in the form of certificates. GOs have the potential to provide a new source of revenue for post-subsidy plants, especially as an organised market for GO trading develops, together with a reference price. GOs play an important role in PPAs to ensure the traceability of green power, and their value can even be factored into developers' bids.

[1] CEER Paper on Unsupported RES, 20 May 2020. https://www.ceer.eu/unsupported-res-paper#

[2] Formerly supported RES installations are already running without any financial support in several Member States, including Germany, Spain and the Netherlands (e.g. via short-term PPAs).

In principle, market players should be provided with incentives to bid at their real marginal costs in the electricity derivative and spot market, meaning dispatch based on the merit order. Even under more market-based support scheme designs such as feed-in premiums, renewable plants may not offer at marginal costs, but at their opportunity costs, i.e. foregone profits from alternative operation and trading strategies. Bidding at real marginal costs guarantees an efficient market and a reliable price signal, which will also be necessary to drive integration between sectors.

Integrating flexibility on the load side is necessary to help absorb increasing amounts of renewables. In times of scarcity, it is the value that consumers attribute to their consumption that will set the price. These price peaks will help RES generators achieve a producer rent and cover their investment costs. Local flexibility markets will help to provide more locational price signals required to integrate renewables.[3]

III - Subsidy design during the transition to full market integration

The full integration of renewables into the market should remain the clear objective, along with the phase-out of subsidy schemes. However, the current energy landscape consists of a range of different markets and instruments, beyond simply the 'energy-only market'. The challenge is how to complete this transition to full market integration while driving down the cost of support schemes and, at the same time, ensuring the renewable targets can be achieved.

A positive trend towards competitive tendering and more market-friendly support such as feed-in premiums and direct marketing is already evident. Competitive auctions have proven beneficial for fostering competition, which in turn reduces financing and power generation costs – both material cost reduction drivers. In fact, some recent examples show that the support to RES investments granted through auctions can be zero or even negative. This was the case, for example, in the auction run in Portugal for solar PV in August 2020 or RES capacity auctions in Spain in 2017.

While support schemes are in place it is important to ensure that the distortion of the energy wholesale market is kept to a minimum. This means that the support schemes need to be market-based, harmonised at a European level and that the subsidy amount is determined by competitive mechanisms (such as auctions). There are detailed design differences in support schemes that can affect their interaction with the market, and the national / regional context is important in this respect. Nonetheless, some important general distinctions in terms of the generators' exposure to market price signals can be made between the different types of support schemes (see the Annex for further detail). Moreover, the upcoming revision of the state aid guidelines for environmental protection and energy should ensure support scheme designs which enable efficient interaction with both the short-term energy market and the forward (derivatives) market.

[3] See Europex paper *A market-based approach to local flexibility – design principles* (February, 2020) Link

Box 2: Contracts for Difference – impact on the forward market

A Contract for Difference (CfD) is a long-term contract, where two parties agree to trade a certain volume of energy for a set strike price. If the market price is higher or lower than the agreed strike price, then the parties settle the difference. These instruments are seen as a way to help lower capital costs and 'derisk' investments in new renewables. However, while the efficiency of market interaction can depend on design details (e.g. settlement period, negative price arrangements, etc.), publicly-backed CfDs pose particular problems in terms of their impact on the electricity forward market, necessary for hedging and the management of price risk.

The 'socialisation' of risk, via off-market interactions between RES operators and the government, effectively reduces the need for operators to hedge their risks on the derivatives market. If this type of CfD is introduced at scale, the reduced participation and liquidity in the forward market will in turn increase the cost of hedging for other generators and market participants. The cost of managing this risk is also ultimately transferred to the public, rather than managed via the competitive energy market. The Europex response to the consultation on the EU offshore renewable strategy (24 September 2020) provides more detail on the potential negative market impacts of CfDs.

Source: Next Kraftwerke

Some developments in the design of support schemes are positive from a market perspective. For example, auctions for renewable capacity could help to incentivise RES generators to offer their electricity at their real marginal costs and improve locational signals, i.e. where to locate renewables across Europe. Other design options should be avoided: for example, full socialisation of the market price risk under publicly-backed CfDs leads to the loss of incentives for renewable investors to hedge their risk on the market.[4]

[4] See *Europex response to the preparation of the EU offshore renewable energy strategy* (September 2020) Link

IV - Conclusions

In view of the ongoing strategic decisions about how to finance and deploy significant volumes of renewable energy in the 2030 and 2050 timeframes, a clear commitment to energy markets is needed. If the renewable build-out is done on the basis of support schemes which shield RES generators from market price risk or 'socialise' this cost, the energy transition will come at an overall higher cost to society and become socially and economically less acceptable. In the long run, the further expansion of subsidies for large RES volumes would also lead to a skewed market in which a portion of RES installations respond to market price signals while significant volumes do not.

Energy markets provide effective short and long-term tools to integrate increasing volumes of renewables, and allow market participants to hedge and manage associated price risk. With the development of demand-side flexibility, the increasing possibilities to 'stack' revenues from different markets, as well as the opportunities from complementary instruments such as PPAs and GOs, operating on the basis of market revenues should be the clear goal for all RES generation. This is necessary in order to support the transition to a decarbonised energy sector at least cost, whilst providing effective signals for the efficient management of the system.

About

Europex is a not-for-profit association of European energy exchanges with 29 members. It represents the interests of exchange-based wholesale electricity, gas and environmental markets, focuses on developments of the European regulatory framework for wholesale energy trading and provides a discussion platform at European level.

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Annex

Table 1 provides a general overview of the interaction of the main types of support schemes with the electricity market. In practice the detailed design of the contracts and the context in which it is set up can make a significant difference – however, some key distinctions between the schemes can be made.

Table 1 – overview of typical remuneration and market interaction of the main support schemes

Support scheme	Remuneration	Level of reaction to market price
Feed in tariffs (FiTs)	RES operators receive a fixed payment for each unit of electricity generated, independently from the electricity market price.	No incentives for installations to respond to the market environment. They neither contribute nor react to the market price signal, which can be problematic for the whole system, for example during periods of negative prices.
Feed-in premiums (FiPs) - fixed	The electricity is sold directly at the power spot market price, and RES operators receive an additional fixed payment on top of this price.	Fixed FiPs have a stronger exposure to market price development and thus leave operators more exposed to market risks, but encourage a more efficient reaction to the market price to the benefit of the overall system.
Feed-in premiums (FiPs) - sliding	Instead of a fixed payment, operators receive a floating or sliding payment which adapts to market prices in order to limit risks as well as prevent windfall profits.	Sliding premiums, where the premium aims to balance electricity price variability, provide more security about future income streams to the plant operator than a fixed FiP; however, the incentive to react to the market price is lower.
Quotas and tradable green certificates (TGCs)	Installations receive certificates for their green final energy, which they may sell to the actors obliged to fulfil the quota obligation. Selling the certificate provides an additional income on top of the spot market price of the final energy sold.	In theory, greater levels of market interaction than a FiP: two support level components (the electricity price and the certificate price) depend on market mechanisms. Provided that the schemes are designed in a technology-neutral way, the most cost-effective technologies are supported.
Contracts for difference (CfDs)	Settlement of the difference between the 'strike price' (a price for electricity reflecting the cost of investing in a particular low carbon technology) and the 'reference price' e.g. a measure of the average market price for electricity in the spot market.	Incentives for efficient commercialisation of renewables on the spot market are comparable under a CfD and under a FiP scheme if the parameters are equal. However, the level of market interaction depends on the precise design elements, such as the settlement period. Certain CfD designs may lead to shielding of generators from market price signals, as well as negative impact on the forward market.[5]
Capacity-based incentives	Power plant operators receive upfront capacity payments for each kW installed instead of payments for each kWh produced. The procurement prices for the capacity support are determined by price auctions.	In principle compatible with competitive electricity markets compared with a production-based scheme because it severs the link between production and payment. Generator operating decisions can be made on the basis of market price signals.

[5] This would be the case, for example, with publicly backed CfDs, where the government assumes the generator's price risks. Alternative designs are possible with non-public counterparties.