CREATING A BUSINESS CASE FOR WIND AFTER 2020

THE ROLE OF REVENUE STABILISATION MECHANISMS AND CORPORATE PPAs

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KEY MESSAGES

- Today, the European power sector faces a **deteriorating investment climate**:
    - **the risk faced by investment in capital-intensive assets is too high** due to several factors that expand beyond energy market dynamics;
    - short-term **wholesale electricity prices are too low and volatile** to provide and predict adequate returns from the spot market revenues only.

- Other elements make the bar for investment in renewables harder to clear than for conventional generation technologies:
    - financing costs have a significant impact on the total costs of projects;
    - renewables tend to **capture lower short-term wholesale market prices** on average;
    - structural market failures still prevent renewables from competing on par with conventional generators, such as the lack of (i) system flexibility, (ii) pricing of environmental externalities and (iii) development of the grid infrastructure.

- In the absence of a level playing field, **revenue stabilisation mechanisms are indispensable to deliver the investment** in wind energy needed to achieve the EU's 2030 decarbonisation targets in the most cost-effective way. **This trend may grow further in the long run** if the cost structure of the power mix shifts toward higher fixed costs and lower variable costs.

- **Revenue stabilisation mechanisms are long-term options** that **complement existing spot market signals**, and provide sufficient **certainty on revenues over the long-term** in order to attract risk-adverse investors, and thus low cost of capital.

- They can **protect consumers from the risk of overcompensation**, **and reduce the costs borne by final consumers for the same level of renewables penetration**. When the market price is high enough to recover total production costs, the generator would either pay back this complementary remuneration or stop receiving support.

- To deliver on these objectives, revenue stabilisation mechanisms should:
    - expose generators to market signals across different timeframes;
    - preferably result from adequate competitive allocation mechanisms;
    - allow technology-specific support; and
    - remunerate energy linked to the full-load hours.

- Alongside revenue stabilisation mechanisms, there is an increasing demand in the EU for other types of long-term signals, such as **corporate Power Purchase Agreements.** This is because the market cannot provide suitable long-term hedging options to investors before sinking investment cost. As generators are increasingly exposed to market signals, there will be more opportunities for such an additional market to develop.

- However, **corporate Power Purchase Agreements alone are not expected to deliver the volume of investments needed to deliver the 2030 targets**. The energy price required to make projects economically viable might be too high to pay for corporate off-takers without any other form of revenue stabilisation mechanisms for the generators.
- Nonetheless, the procurement of renewable energy by corporations can be facilitated by:
  - clarifying existing legislation in Europe for any legal restrictions related to long-term competitive contracts;
  - completing the implementation of the Guarantees of Origin tracking system with full disclosure for all technologies to avoid the risk of double-counting; and
  - providing guidelines and model contracts to create more streamlined processes and open the market to smaller enterprises.

1. A COST-EFFECTIVE TRANSITION REQUIRES REVENUE STABILISATION MECHANISMS

Despite tremendous cost reductions[1] over the last decade, wind assets are still unable to recover their total costs through revenues coming from the spot market only. In fact, for the foreseeable future, no new electricity generation asset can. The following sections elaborate on:

(i) the increasing investment risks faced by capital-intensive assets
(ii) the inability of the spot market to provide stable revenues over the long term
(iii) how revenue stabilisation mechanisms can foster investments in renewables at least cost

1.1. INVESTORS FACE A MORE RISKY AND VOLATILE ENVIRONMENT

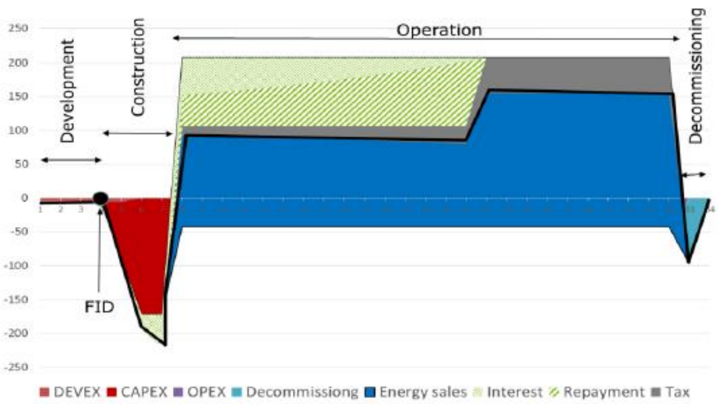
Renewables investors base their decisions on the returns they expect to obtain from a project, over a certain timeframe, for a given level of risk. Prior to the investment decision, they

[1] The IEA suggests that this trend will continue to 2030 and beyond both for onshore (-24%) and offshore (-30%). Wind energy is now the most competitive form of new electricity generation capacity in many parts of Europe.

determine the risk profile of the project by analysing the different risks associated to revenues and costs: policy changes, grid access conditions, level of social acceptance etc. Some exist over the entire lifetime of the project, others occur at specific stages only. Each risk has a different weight on the project's profitability. The riskier the profile, the higher the return, i.e. the capital investors make available will be more expensive.

Investments in capital-intensive technologies present a high risk profile today. One important reason is that upfront capital expenditures (CAPEX) and the cost of capital represent a high share of the total project costs, compared to operational expenditures (OPEX) that occur after the commissioning of the plant. Figure 1 gives an indicative example of the cash-flow of a 500 MW offshore wind energy project with CAPEX of €1.4 billion. The black line represents the shape of the free cash flows. To be attractive to investors, the cash inflows generated during the entire project lifetime (positive value) should at least equal the initial cash outflow (negative value).

Figure 1 Example of a cash-flow for a 500 MW offshore wind project (M€)



Source Diacore project (2016)

These large upfront CAPEX costs have two consequences:

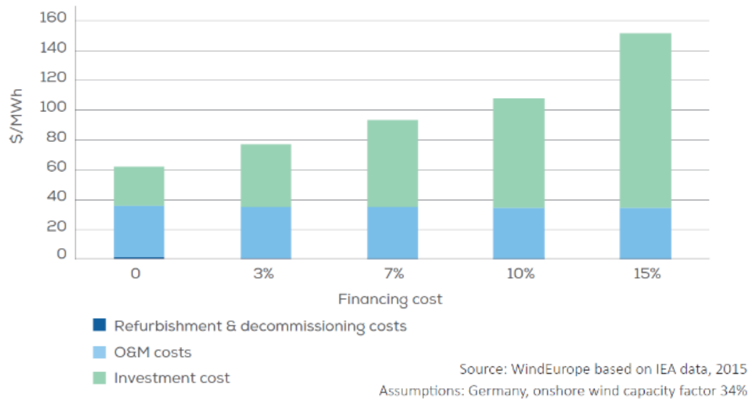
- There is a negligible number of market-based investments in renewables today even when the technology is competitive on a levelised cost of energy (LCOE)-basis[2]. Once the plant is built, and the cost of investment is "sunk", investors would face too high risk of pressure on revenues as regulators and off-takers are not equally contractually bound for the long term due to the lack of liquid spot and long-term forward markets[3];
- Renewables projects are very sensitive to cost of capital. Figure 2 shows that a Weighted Average Cost of Capital (WACC) of about 10% can increase the LCOE of onshore wind by

[2] According to the IEA's World Energy Investment 2016, 95% of power generation investments rely on vertical integration, long-term contracts or price regulation to manage risks. Utility-scale renewables benefiting from long-term fixed-price contracts or regulated pricing represent over half of the total power generation investment worldwide.

[3] This is often termed in economic literature as the 'hold up' problem. See Brattle Group, the importance of long-term contracting for facilitating renewable energy project development (2013).

approximately 70% as compared to a 3% financing rate. This translates directly into a higher cost for end consumers.

Figure 2 Impact of different WACC levels on LCOE onshore wind



Source WindEurope, 2016

As the cost structure of the EU power mix shifts toward a high CAPEX / low OPEX ratio, the ability of the current market design (based on short-term energy only market) to allow investors to recover investment costs is coming into question[4].

1.2. THE ROLE OF THE WHOLESALE SHORT-TERM MARKET HAS CHANGED

The major risk for investors in power generation assets is the long-term revenue forecast (predictable cash flows). Although the short-term wholesale electricity market (hereafter "spot market") remains an efficient dispatch signal, it currently fails to send long-term signals to investors. Day-ahead wholesale electricity prices are too difficult to predict, and currently at the lowest level in a decade[5]. Producers' infra-marginal rents (i.e. gross margin) are consequently too small to allow any investors to recover their long-term marginal costs. The reasons for such low prices are several:

(i) A market over-supplied in combination with a declining demand (and increased end-use energy efficiency)

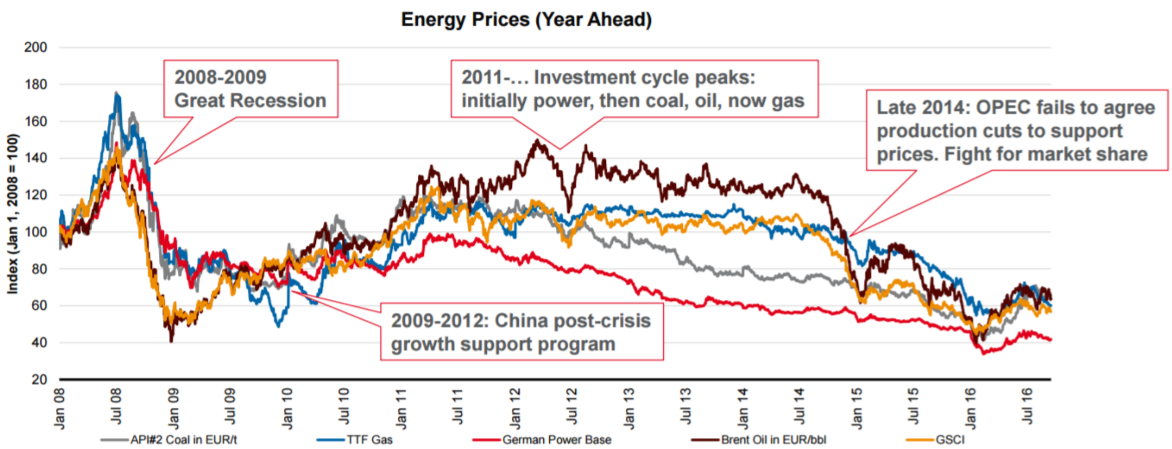
[4] Some economists argue that a power market based on marginal pricing with increasing shares of low marginal cost technologies will lead to collapse in prices.
[5] According to the European Commission, the pan-EU average day ahead price was 33.2 €/MWh in Q1 2016

High growth expectations before the financial crisis triggered considerable overinvestment in several Member States[6]. In parallel, total electricity demand in 2014 for the EU-28 was 7-10% below Member States' projections of 2010 and 6.3% below the pre-crisis level[7].

(ii) Decrease of commodity prices (coal and gas) on international markets

Coal prices in Europe fell by 40% since the beginning of 2011, mainly due to the boom in shale gas production in the United States and an oversupply situation in Asia. Figure 3 shows a strong correlation between the coal (grey line) and power prices (red line); the European Commission itself identified fossil fuel as a key driver for low power prices[8].

Figure 3 Global trends and business cycles drive European power prices



Source Bloomberg and AXPO

(iii) The EU Emissions Trading System (ETS) fails to reflect the cost of carbon

The CO2 price should send a long-term signal to electricity generators by pricing the real environmental costs of emitting CO2 per unit of power produced. Because of a structural oversupply and stop-and-go policies, the political risk associated with carbon pricing is too high, and its current level too low to foster new investments in renewables. While there is an ongoing reform of the EU Emissions Trading System (ETS), WindEurope has significant doubts about carbon pricing as a single driver for either high-carbon retirement or renewables investments[9].

(iv) The impact of increasing renewable energy generation on prices

[6] The introduction of poorly designed capacity payments (Spain) or market exit barriers (e.g. Germany) have also artificially extended the overcapacity situation. In Spain, most of the peaking gas units today operate at very low utilisation rates (below 20%).

[7] CEPS and ACER data (2016)

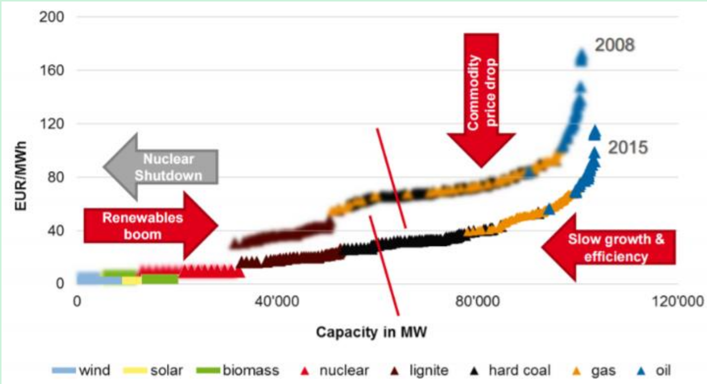
[8] European Commission, Energy prices and costs in Europe (2014)

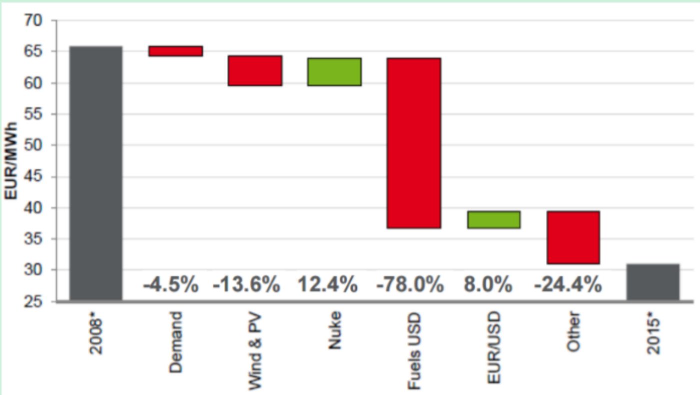
[9] According to recent estimates from Thomson Reuters, carbon price will be no more than 14€ on average between 2017 and 2030.

In the short-term, renewables put downward pressure on day-ahead prices[10] as those depend largely on consumer patterns and weather (weekday vs. weekend, temperature, solar irradiation, wind speed). Limited flexibility exacerbates this effect[11]. In the long term, this effect is however relatively small. Penetration rates are still too low in most Member States for renewables to be the main driver for such low prices.

Box 1: What is really driving the spot prices down in Germany?

Figure 4 German merit order 2008 vs. 2015, and decomposition of the price destruction





Source Axpo, 2016

In Germany, the spot price decrease in the period 2008 to 2015 has been mainly driven (78%) by the drop in the price of the fuel used by the main price-setting technology – coal.

On figure 4, this is shown by the significant downward shift of the price level from 2008 to 2015. The increase in wind and solar capacity shifts the supply curve to the right, but is almost entirely offset by the shutdown of nuclear facilities. Demand increase also plays a significant role shifting the price setting to the left leading to lower price on average.

WindEurope believes this situation is unlikely to change over the foreseeable future, but could be significantly improved by the forthcoming market design initiative[12]. Moreover, other factors that specifically impact renewables impede any costs recovery through the energy-only markets:

[10] "Merit order effect". See EWEA, Wind energy and electricity prices (2010)

[11] Lack of demand side response, must-run conventional generation (for technical or economical – opportunity costs of shutting down and ramp up plants – reasons), ill-designed renewables support schemes etc. See Agora Energiewende, Negative electricity prices: causes and effects (2014)

[12] See WindEurope position paper on Market Design (2015)

- Renewable energy installations are variable by nature and see wholesale prices decrease when they are producing and demand is low[13]. Scarcity prices arise mostly when they are not producing, which means they rarely benefit from price spikes;
- In many Member States, existing rules prevent renewable energy producers from accessing some markets such as ancillary services and are therefore unable to gain additional revenues;

1.3. ENSURE PREDICTABILITY TO INVESTORS AT THE LEAST COST FOR CONSUMERS

Despite the launch of new financial products by power exchanges[14], there is today no adequate option provided by the market for investors to hedge against this aforementioned risk. Commercial long-term contracts could also bridge this gap but there is only limited demand for such contracts and some other hurdles exist (see part 3).

In the EU, forward markets lack liquidity[15]. Even in the most liquid forward markets, contracts usually do not expand beyond 3-4 years, while the operational life of assets extends significantly beyond that. In Germany, contracts secured for the forward year 2019 are already negligible – 2% of German gross electricity production in 2014[16]. Such lack of liquidity is due to several factors, including consumers' uncertainty with regard to their future energy demand, credit risk / collateral growing exponentially with the contract duration or consumers' lack of appetite for long-term hedging as they feel they are already hedged by the governments themselves.

In the absence of hedging options, the long-term predictability of revenue streams for new generators is limited, and the "hold-up problem" is likely to remain. Policies can mitigate investment risks and attract low risk investor capital via well-designed revenue stabilisation mechanisms. These mechanisms provide a complementary remuneration to spot market revenues, not a substitute. They do not necessarily need to be high but stable over the long-term. This will lead to significant savings for the end consumers because they will bring financing costs as low as possible (see box 2), and avoid the risk of overcompensation avoided (see part 2).

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[13] See annex 4.1

[14] On October 4th, EEX launched trading in wind power futures on the derivatives market to hedge against volume risks in the generation of wind electricity within the German/Austrian market.

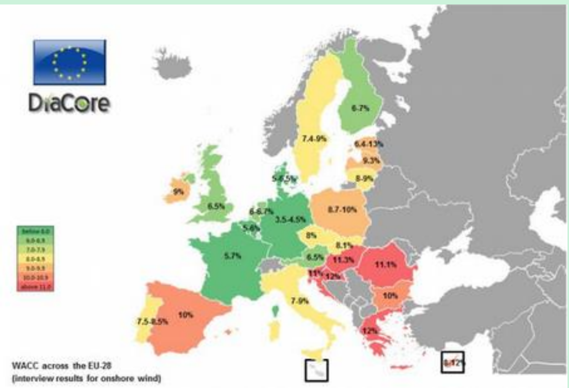
[15] According to Economic Consulting Associates' study for ACER (2015), the churn rate (volumes traded on forward markets as a proportion of physical consumption) in EU forward markets range from below 100% to over 700%. A 300% threshold is recommended to constitute a liquid market, although some analysts and regulators (cf. Ofgem) use a 700% threshold.

[16] See CEPS, the EU power sector needs long-term price signals (2016)

Box 2: Lower financing costs mean lower support for renewables development

Figure 4 shows that financing costs for onshore wind projects vary significantly across the EU, from 3.5% in Germany to 12% in Greece. The current average WACC across the EU is about 8.3%. The main reasons for such differences are risk perception by investors (stable regulatory framework) the general country risk and also the competition between debtors.

Figure 4 WACC for onshore wind turbine, 2014



Source Diacore project, 2016

These varying costs of capital can lead to significant cost differences in the development of similar renewable energy projects between the Member States. Under a strong decarbonisation scenario, the project partners argue that reducing this WACC to 5.9% could reduce the policy costs for onshore wind by more than 15% in the build-up to 2030. Thus, a 2.4% change in WACC can lead to €1.3 bn of savings per year on average for consumers.

Until existing market failures are addressed and a level playing field exists amongst all generators, including a cost-reflective carbon price, the deployment of revenue stabilisation mechanisms is the least costly way to deliver a secure decarbonised power sector in line with the EU policy objectives for 2030.

2. KEY DESIGN PRINCIPLES OF REVENUE STABILISATION MECHANISMS

Historically, publicly funded support schemes have been introduced to drive the deployment of renewables generation in order to accelerate the development of specific technologies (via technology development and economies of scale). However, these incentives did not address potential short-term market distortions, as the share of renewables was still relatively small.

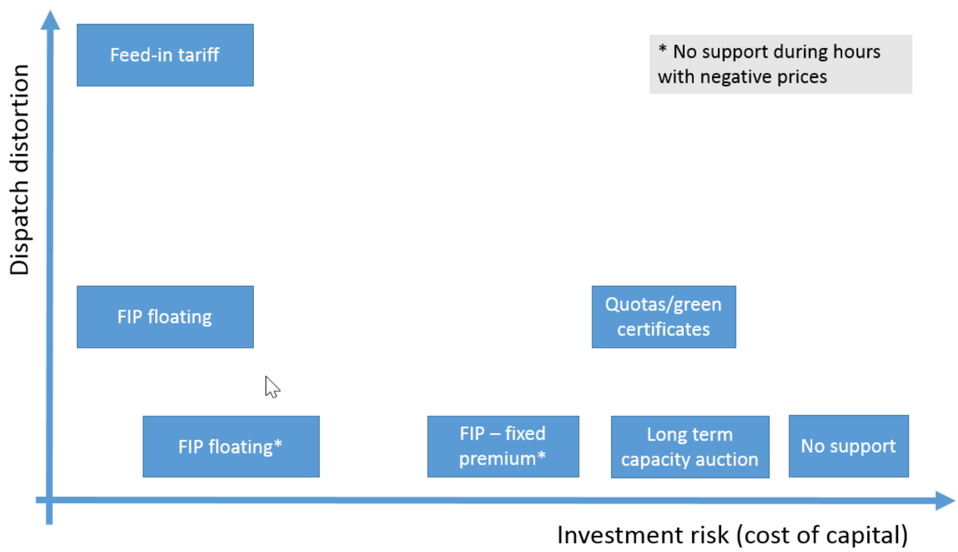
With higher shares of renewables, this impact must also be considered. Their design should promote competition amongst market parties, and strike a balance between minimising revenue risk for investors while maintaining the incentives to react on short-term market price signals. The following sections lay out the four general principles on which revenue stabilisation mechanisms should be based. They should:

(i) expose generators to market signals across different timeframes;
(ii) preferably result from adequate competitive allocation mechanisms;
(iii) allow technology-specific support; and
(iv) remunerate energy linked to the full load hours.

2.1. EXPOSE GENERATORS TO MARKET SIGNALS

WindEurope favours the use of Feed-in-Premiums (FiP) or Contract for Difference (CfD) to expose generators to market signals. Unlike Feed-in-Tariff schemes (FiT), FiP – both floating and fixed – expose producers to different levels of market risk and lead to various results in terms of dispatch decisions (see figure 5). This is to be combined progressively by introducing the same balancing responsibilities on all market players. Hence, renewable energy producers are incentivised to keep their schedule by selling or buying on short-term markets instead of paying the possibly higher cost of balancing energy.

Figure 5 Investment risk vs dispatch distortions for different economic support options



Source WindEurope based on Market4RES project, 2016

The main design parameter for a FiP scheme is the definition of the premium which fundamentally affects the risk transferred to the producer: fixed or floating (with or without cap and/or floor).

In a fixed premium system, the risk borne by the producer is relatively high, because the total revenue is directly dependent on the evolution of power prices over the long term[17]. On the other hand, if market prices are higher than expected in the longer term, this design feature is also unfavourable to the consumers because the level of support will turn out to be higher than needed for a reasonable return.

In a floating premium system, the producer will receive as a premium the difference between a strike price (either set administratively or via an auction) and a reference market price. Whenever the reference market price is above the strike price, the producer either pays back this difference (e.g. UK CfD scheme) or receives zero support (e.g. Germany). Therefore, if the strike price happens to be set close to the reference market price, the possibility of repayment removes any upside for the generator and protects consumers from overcompensation.

Box 3: comparison of the main premium models emerging in the EU

Premium models are effective but there is no one-size-fits-all solution as even within these mechanisms many design variations exist. It is premature for the industry to conclude on the ideal design.

First, the frequency at which the reference market price would be adjusted is decisive. The regulator should recalculate it regularly so that the total price for renewables generation (i.e. electricity price plus premium) is in line with a target value (resulting from a competitive tender, or administratively set value). Today such adjustment can occur:

- Hourly or daily: some market exposure as with FiT (CfD in United-Kingdom)
- Monthly: increased market exposure, high degree of certainty (Germany)
- Yearly: strong incentive to perform better than the expected market outcome (the Netherlands, Spain)

Secondly, there should be an appropriate set of market price value. It can be:

- the average market prices as expressed by the baseload price
- the specific market price received by the wind farm in each specific hour (Italy)
- the average market prices adapted to the production profile of the technology (Denmark)

The moment at which the premium is set is a critical design feature. Some Member States propose *ex ante* payment whereas other provide it *ex-post*.

[17] In Denmark, the fixed premium is based on a certain number of full load hours. This incentivises the producer to stop generating during negative prices hours, because it is more profitable to provide instead downward regulation in the balancing market. As a result, it will displace its production to another period of the year (when the price is positive again).

2.2. RESULT FROM AN AUCTION PROCESS

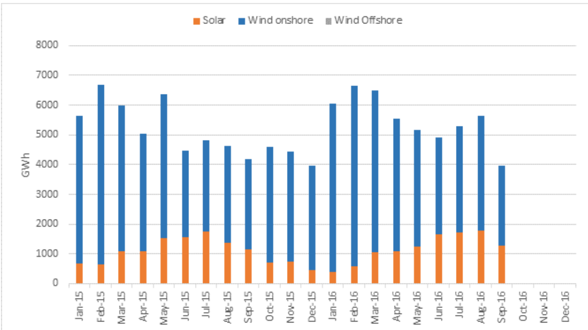
The State Aid Guidelines for Energy and Environment 2014-2019 call for the introduction of competitive bidding procedures for the allocation of financial support. Their use is still at an early stage. Public authorities will seek the appropriate tender format on a learning-by-doing basis thus challenging the industry to adapt their business models to constantly evolving tender arrangements.

The ability of tenders to deploy renewables cost-effectively is highly dependent on their design. For a tender to be effective, it needs to achieve both competitive prices (cost-competitiveness criteria) and high realisation rates (efficiency criteria). Key elements include notably the number and time of auction rounds[18].

Properly designed auctions to allocate revenue stabilisation mechanisms can allow for cost-effective deployment of renewables. A relevant example is the result of the Danish tender for the concession to build the 600 MW offshore wind farm Krieger's Flak in the Baltic Sea last November. The clearing price was 49.9 € / MWh. This is by some distance a record low for offshore wind, and proves that revenue stabilisation does not necessarily imply high level of support but stable revenues over the long-term.

2.3. ALLOW TECHNOLOGY-SPECIFIC SUPPORT

Figure 6 Monthly production values of wind and solar (Spain, 2015)



Source WindEurope, 2016

In the long term, a wide portfolio of complementary technologies will provide the most cost-effective solution for system integration and decarbonisation.

As an example, figure 6 shows a good complementarity between solar PV and wind energy production in Spain that can help mitigate the impact of their variability on system adequacy.

In order to encourage investments in a wider range of technologies with very different characteristics and high potential (in terms of energy production and cost-reductions through learning-by-doing effects), technology-specific support should continue to play a prominent role. Technology-neutral approach are likely to result in suboptimal outcomes.

[18] See WindEurope, design options for wind energy tenders (2015)

Introducing technology neutral auctions for technologies with different cost levels will result in a "winner takes all" scenario, leave the energy system with a less diversified generation mix and industry faced with boom and bust cycles. It can also result in an over-compensation of the cheapest technologies as the most expensive one might set the auction price (in case of marginal price setting mechanism). Neither of the consequences are to the benefit of the consumer. A technology-neutral approach would stifle the maturing technologies needed to ensure full decarbonisation while ensuring a high degree of security of supply.

2.4. REMUNERATE ENERGY LINKED TO FULL LOAD HOURS

First, revenue stabilisation mechanisms that reward the producer based on their energy production (€/MWh) are preferable for a number of reasons:

- Support can be better adjusted to reflect market dynamics (e.g. electricity prices), since the premium would represent the difference between market price and the needed return of investment (strike price).
- Supporting energy delivery ensures reaching long-term renewable energy targets (as share of energy demand).
- Economic efficiency is maximised through incentivising generators to maximise output from a fixed capital investment.

Second, revenue stabilisation mechanisms that reward the producer based on their installed capacity (€/MW) may help avoid short-term market distortions, but they come with important drawbacks:

- For most generation technologies (i.e. all except peaking renewables technologies), capacity payments introduce a bias on investment decisions. When considering the investment options, project developers could choose to install more powerful machines producing less energy (e.g. with oversized electric generator but a smaller rotor, aiming to maximize their revenues from the support instead of maximize their production).
- This behaviour could lower the load factor, leading to higher connection costs, higher balancing costs (in the case of forecast errors) and overall complicating system integration.

Considering the first type of mechanisms (remunerating energy production), it exists significant design variations that will either increase generators' exposure to the price or to the volume risk:

- Generators are more exposed to the volume risk if the remuneration is based on the actual energy delivered like the CfD scheme in the UK. In that case, generators are fully hedged against any price variations but might be exposed to revenues loss in case of negative prices hours[19];

- Generators are more exposed to the price risk if the remuneration is based on the expected energy[20] that they will produce. In that case, generators are incentivised to adapt their production according to market price fluctuations. It also enables their participation to the balancing market because there is no risk to lose the premium[21]. Within such model, there are possibly two ways to determine the remuneration of generators. It is either adjusted based on:
  - the total energy delivered in a certain period (e.g. a year, a month, a week). Hence, **the frequency at which the regulator revises the reference market price will influence the level of risk exposure (see box 3); or**
  - the energy production profile (see annex 4.1 on system-friendly wind turbines).

3. CORPORATE PPAs AS AN ADDITIONAL LONG TERM INVESTMENT SIGNAL

Alongside revenue stabilisation mechanisms, corporate energy procurement can play an important role in helping the EU deliver on its climate and energy goals. Corporate renewable Power Purchase Agreements (PPAs) are rapidly emerging as a business model in Europe to facilitate investments for utility scale projects.

Corporate PPAs provide an opportunity for project developers to directly sell their electricity to consumers who are seeking a hedge against the price uncertainty in the industrial retail market. Unlike contracts in the forward electricity markets, corporate PPAs extend over a longer period of time, usually more than 10 years. They have a negotiated price for the electricity from a particular facility. This provides the operators with the stable revenues they need as early as possible in the investment decision process.

The additionality principle corporates apply requires them to purchase electricity from greenfield projects and therefore bring new capacity online. In other words, these new investments would not have been carried out under the existing market conditions or legal framework. However,

[19] The State Aid Energy Guidelines demand that a support regime should not give any incentives for the production of renewables electricity in this situation. These negative prices hours represent a significant risk for investors as their recurrence is difficult to predict.
[20] Floating capacity premium like in Spain
[21] That would otherwise be subjected to sell energy in the day-ahead market.

additionality can also be defined in a grand scheme to finance operational projects, provided the proceeds from such a transaction will help the developer finance additional renewable power.

Today, Europe has a cumulative capacity of approximately 2 GW contracted through corporate PPAs, 1.6 GW of which has been procured in the last four years. Further exposure to market signals could trigger an increase in corporate electricity procurement as generators look for additional sources of revenue. For instance, corporate renewable PPA deals have increased dramatically in the UK in the last three years[22], whereas in markets like Norway and Sweden they have been a key element for investment (see figure 7).

Figure 7 Corporate PPAs by country 2013-2016 [23]

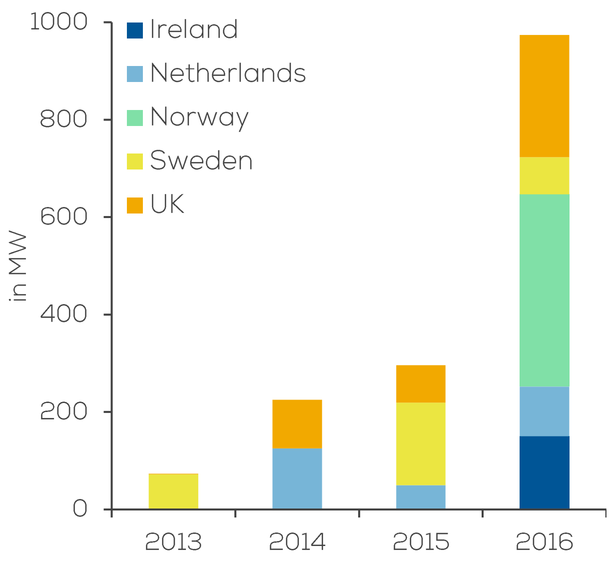
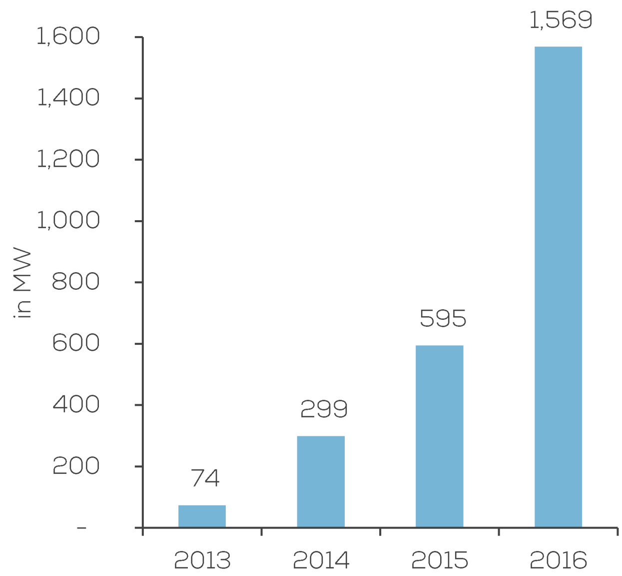


Figure 8 Cumulative contracted capacity 2013-2016



Source: WindEurope

While corporates have the potential to drive wind energy deployment, they alone are not expected to deliver the volume of investments needed to deliver the 2030 renewable energy target. The energy price to pay in such contracts might be too high for corporate off-takers without any other form of revenue stabilisation for the project.

3.1. MARKET TRENDS

Demand for corporate renewable PPAs is expected to grow significantly, with two factors at play. First, major corporates are placing increasing importance on their sustainability agendas. More companies are procuring, or aiming to procure, 100% renewables for their power supply. Currently, the RE100 initiative counts 81 companies that have pledged to go 100% renewable.

[22] BNEF 2016, Corporate renewable energy procurement
[23] WindEurope has tracked corporate PPA deals in Europe for the last four years

Secondly, the economic context post-2020 will be an important driver for corporate PPAs in Europe. Cost reductions and market exposure will incentivise renewable energy developers to look for alternative off-takers.

To put this into context, there is hardly a business case for corporate PPAs in countries with government-backed Feed-in-Tariffs (FiT) like France or Finland. FiT jurisdictions do not incentivise developers to enter into long-term agreements. There is more demand for such contracts in markets where the revenue stream for a large share of wind project revenues is highly exposed to merchant risk, such as Norway and Sweden. The introduction of auctions in most EU countries could create opportunities for more corporate PPAs.

Figure 9 Contracted capacity by technology[24]

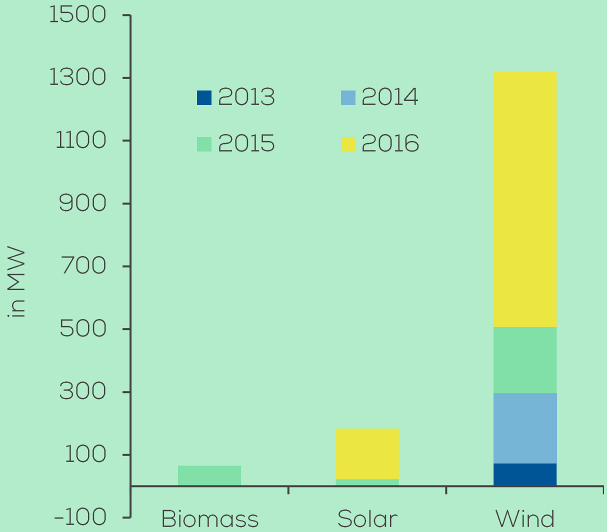
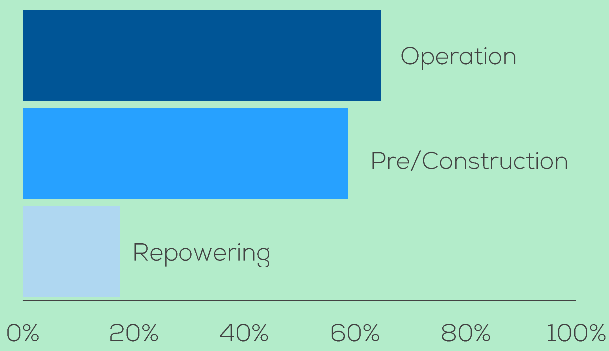


Figure 10 Asset Demand: stage of project[25]



Source: WindEurope

Onshore wind is very well placed to accommodate corporates' needs for renewable electricity due to its scale and risk profile.

Corporate off-takers are mostly interested in assets **between 50 MW and 200 MW capacity.**

Fragmented assets come with high transaction costs. Assets over 200 MW add more risk to the portfolios of both generators and off-takers

Independent Power Producers are mostly interested in operational assets for refinancing purposes, short term PPAs coming to an end, or renegotiation of PPA contract terms.

Corporate off-takers are mostly interested in new assets, guided by the additionality principle.

Repowering is an option corporate off-takers are less inclined to explore, as it interferes with the additionality principle.

[24] WindEurope has tracked corporate PPA deals in Europe in the last four years
[25] WindEurope : 2016 Survey on corporate renewable PPAs

Independent power producers will continue to play an important role in providing long-term contracts to off-takers. Contrary to independent generators, utilities have been reluctant to engage with corporate purchasers through bilateral long-term contracts. Ex-post antitrust enforcement of long-term contracts and the relatively smaller size of such transactions compared to the overall utility portfolios, have made them shy away from corporate renewable PPAs.

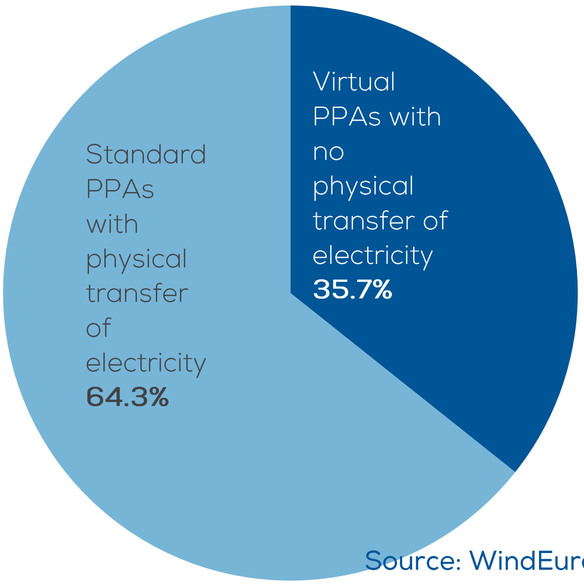
Corporate PPAs are mostly used with cost competitive technologies such as wind energy and solar PV. Over 1.3 GW of the renewable capacity contracted in the last four years is in wind energy. Due to its scale and risk profile, onshore wind is very well placed among other low carbon technologies to accommodate corporates' needs for renewable electricity.

3.2 CORPORATE PPA STRUCTURES

There are multiple corporate PPA contractual agreements, varying from the simple purchase of power, to price swaps, contract for differences, and options. In most cases it is the electricity market and the corporate strategy of the buyer that will determine the type of agreement.

The predominant model in Europe is standard PPAs with a physical transfer of electricity. Virtual PPAs are mainly used in the UK, and outside of Europe in the US, as commodity hedges and derivative contracts.

Figure 11 Corporate renewable PPA contracts[26]



Source: WindEurope

Corporates will tend to look for projects that are located in the same grid network as their industrial facilities. This is commonly referred to as a standard PPA. While proximity of the asset and the wind farm is not a requirement for corporate off-takers, it remains important in the European market to mitigate certain risks like balancing, curtailment and financial exposure to price risk.

In virtual PPAs, the generating asset and the corporate off-taker do not have to be located in the same grid. While they could be located in different countries, this will require the parties to consider further risks related to cross-border balancing and the price correlation between the retail price in the buyer's market and the wholesale price in the developer's market. Moreover, such transactions come with lower reputational benefits. They often do not meet the credibility requirements to demonstrate sustainability as a business model integrated in the general corporate strategies.

[26] WindEurope: 2016 Survey on corporate renewable PPAs

3.3 OVERCOMING THE CHALLENGES

Despite increasing demand for corporate PPAs, corporate renewable energy procurement faces policy and market challenges. Financial and regulatory incentives are needed to promote the use of corporate renewable PPAs to open the market and generate opportunities for large corporations, as well as SMEs.

These measures will significantly help the uptake of this recent market, and complement other revenue stabilisation mechanisms in delivering the long term investment signals needs.

(i) Removal of regulatory barriers

Unlike the US, Europe is in a favourable position, where corporate PPA contracts are legally allowed in most countries. However, the conclusion of PPAs may be challenging in certain jurisdictions. Private developer and off-taker contracts for electricity trading may not be possible in all Member States or lack proper incentives. Clarifying existing legislation across Europe for any legal restrictions related to long-term competitive contracts will help this market take off beyond the UK, Nordics and Netherlands. WindEurope will be proactive in identifying and tackling those barriers with its national associations.

(ii) Full implementation of the Guarantees of Origin (GO) tracking system

Corporations requiring a zero carbon power supply are faced with the challenge of tracing renewable electricity production and demonstrating additionality. One way to do this is to buy bundled products: purchase both renewable power from a given asset and GOs. GOs are then retired each year against consumption.

However, the market currently does not provide adequate solutions to deal with this issue. The functioning of GOs as a tracking tool presents certain challenges. First, the system is not fully implemented across Europe. Not all Member States have established Issuing Bodies and National Registries for GOs. Second, their uneven implementation in Europe represents a risk of double counting. Full disclosure for all technologies and harmonised use of GOs would provide for a coherent implementation of the GO tracking system, improve reliability and avoid the risk of double support[27].

(iii) Provision of guidelines and template contracts

Corporate PPAs can be quite complex contracts to structure, with negotiations that can extend up to 18 months. Issues to be addressed in these contracts include regulatory risk, price risk, financial exposure on the underlying commodity, as well as balancing and curtailment risk.

Establishing guidelines and a template term-sheet will help consumers to analyse their energy needs and compare offerings in an efficient approach. This will create quicker and more

[27] BEUC, 2016 : Current practices in voluntary and consumer-driven renewable electricity markets

streamlined processes for corporate PPAs. At the same time, it will open the market to public entities, and other companies who lack the in-house expertise to structure such transactions.

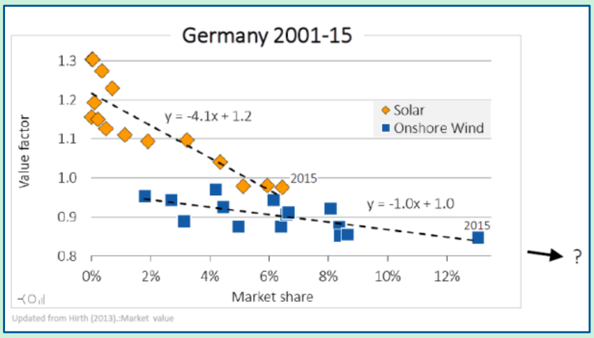
4 ANNEXES

4.2 "DOES WIND "CANNIBALISE" ITS OWN VALUE?

Some power economists[28] argue that the "value factor" or "market value"[29] of wind and solar PV would remain intrinsically limited as their share in the power mix increase, i.e. each MWh of wind and solar would become less and less valuable as their proportion in the total electricity supply increase. This argument is based on the effect that, in windy and sunny hours, the additional supply of power depresses the electricity price, tending towards the marginal cost of operation. By reducing wholesale prices when they produce, variable renewables would therefore undermine their own competitiveness.

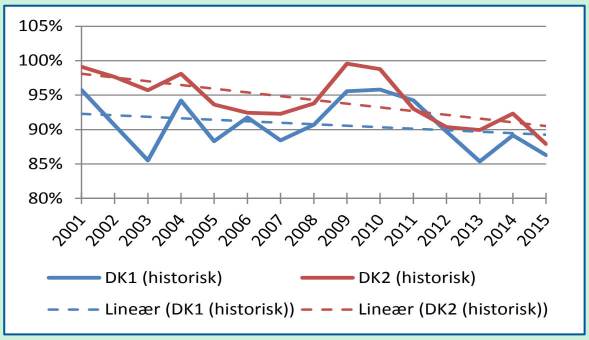
However, national cases seem to differ considerably. Empirical studies for the German system (see figure 11) provide evidence of this effect. On the contrary, in Denmark, with a wind share of over 40% in 2015, the market value assessed by Energinet.dk is 0.88-0.92 as compared to the reference case (see Figure 12), while the theoretical example shows that with a 13% share it should already be at 0.85.

Figure 11 Value factor = market value / base price. Each dot is one year



Source Leon Hirth, 2015

Figure 12 Market value of wind in the Danish system



Source Energinet.dk, 2015

Such differences can be explained by differing levels of system and market integration, as well as the rate of electrification in other sectors such as heating and cooling or transport. For instance,

[28] Lion Hirth & Simon Müller, 2016

[29] The ratio of the market price during windy hours and the average base price.

this effect would be more important in power systems with limited flexibility and structural oversupply.

Solutions exist to maximise the value of variable renewable energy sources in the system (market). Among them is demand response, storage, long-distance interconnection, reduction of thermal must-run (CHP, ancillary services), improving the spot and balancing market design.

In parallel, a number of improvements come from the renewable technology side: optimized geographic allocation of variable renewables generators and increase of capacity factors from both PV and wind energy. In solar PV systems, East-West oriented solar modules can help increase capacity factors. In wind energy, new turbine designs can help tap into low wind speeds, increasing capacity factors. These low-wind turbines with higher tower, larger rotor and a well-fitted generator's size decrease the power density of turbines decreases (W/m2). But they smoothen the energy production profile of the power plant and increase its capacity factor significantly (from an average of 20-24% up to 40% for onshore wind energy system). Higher capacity factors mean that electricity production becomes more balanced, and thus market value increases.

4.2 EXAMPLES OF CORPORATE PPAS

Wind farm Krammer in the Netherlands

In November 2016, DSM, AkzoNobel, Google and Philips joined forces to source energy from a local community wind farm in the Netherlands. A total of 0.35 TWh a year will be sourced from Windpark Krammer once it becomes fully operational in 2019. This is equivalent to the total annual consumption of 100,000 households. This agreement is the first of its kind to establish a consumer-to-business partnership, for two main reasons. The consortium brings together four leading companies to share experiences and jointly explore market opportunities. The wind farm is owned by the local community, some 4000 members in the province of Zeeland.

Google Nordics Power Purchase Agreements

The Nordics is a market where Google has concluded several deals. To date, they count six PPAs or more than 500 MW of wind capacity contracted. There are two operational projects, one about to be commissioned and three projects coming online by 2018. In the NordPool market, Google works with local developers who either invest directly in the project or raise financing from institutional investors. The joint electricity certificate scheme between Sweden and Norway makes the Nordics attractive from corporate's perspective.

Horns Rev 2 offshore wind farm in Denmark

In May 2007, Novo Nordisk – a pharmaceutical company reliant on energy intensive production – signed a power purchase agreement with DONG Energy to buy electricity from Horns Rev 2 offshore wind farm. With a capacity of 209 MW, the wind farm became operational in 2009, supplying with wind power all Novo Nordisk facilities in Denmark. This is amongst the first corporate renewable PPA to be concluded in the offshore wind sector.

Fosen onshore wind farm in Norway

In February 2016, Norsk Hydro – a global aluminium supplier – signed a 20 year power purchase agreement to off-take a third of the annual production capacity of the Fosen onshore wind farm. The contract will cover in total 18 TWh for the 20 year period and will contribute to supplying power to Hydro's aluminium plants after the existing long-term power contract with Norwegian state utility Statkraft expires in 2020. This contract shows the synergies in Norway between high electricity consumption industries and renewable energy sources. With a capacity of 255 MW, Fosen is one of the six wind farms being developed in central Norway, in what is today the largest onshore wind project in Europe.