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Key support elements of RES in Europe: moving towards market integration

CEER report

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INFORMATION PAGE

Abstract

This document (C15-SDE-49-02) presents a detailed analysis of the key aspects of operational support schemes for renewable energy sources across the European Union and explains the developments expected in the years to come.

It explores the different procedures for determining levels of RES support, both administrative and competitive, and sets out alternative mechanisms to enhance the market integration of RES.

The purpose of this CEER report is to provide insight to policy-makers about the diversity and complexity of RES support schemes, notably by presenting the different design options and the challenges their realisation poses.

This report should be read in the context of the new requirements for renewable aid as set out in the State Aid Guidelines and the current ongoing discussion about a new electricity market design which more effectively integrates renewable energy sources into the market.

Target Audience

RES operators, energy suppliers, traders, electricity customers, electricity industry, consumer representative groups, network operators, Member States, academics and other interested parties.

Keywords

Renewables; Support schemes; Market integration; Competitive bidding procedures; Certificate schemes; Feed-in Premium; Feed-in Tariff; State Aid Guidelines (EEAG); National Regulatory Authorities (NRAs).

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Related Documents

CEER documents

- Joint ACER-CEER response to the European Commission's Consultation on a new Energy Market Design, October 2015
  http://www.ceer.eu/portal/page/portal/EER_HOME/EER_PUBLICATIONS/CEER_PAPERS/Cross-Sectoral/Tab1/ACER_CEER_EMD%20response_FINAL.pdf

- Status Review of Renewables and Energy Efficiency Support Schemes in Europe in 2012 and 2013, January 2015, C14-SDE-44-03
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EXECUTIVE SUMMARY

Background

National support schemes have played an important role in the deployment of renewable energy sources (RES), together with ambitious national and European targets, and they will remain a reality at least in a mid-term perspective, until in a longer run an improved ETS becomes the main driver for investment in RES.

However, RES support schemes need to be adapted in order to achieve greater cost-effectiveness and better integration of RES into the market, as set out in the State Aid Guidelines for Environmental protection and Energy (EEAG). The guiding principles behind the EEAG guidelines are essential to achieving the 2030 RES objectives in an efficient way.

The ongoing developments in the field of RES support schemes should be seen in the overall context of the discussion linked to the organisation and regulation of a future-oriented European energy system, in which RES will be perhaps the main source of energy generation and will play a key role in achieving the transition towards a low-carbon energy system.

Objectives and Contents of the Document

The purpose of this CEER report is to provide insight into RES supports schemes, by presenting different design options and outlining the challenges inherent in each approach. A number of relevant case studies from various MS are provided as annexes to illustrate how national support schemes can be adapted to meet the requirements for greater cost efficiency and deeper market integration.

This report focuses on operational support granted to electricity originating from renewable energy sources and develops detailed analysis of the different procedures for determining support levels (covering both administrative and competitive approaches). It then goes into more detail on alternative mechanisms to enhance market integration of RES. In addition, the report explains the role played by National Regulatory Authorities (NRAs) in the implementation of RES support schemes.

The contents of the report are as follows:

- The legal framework for the design of national RES support schemes and NRAs role in the process;
- Administrative and competitive procedures for determining support levels for RES; and
- Support instruments for achieving a deeper market integration of RES.

Brief summary of the conclusions

Major adjustments to national support schemes are still pending

The practical implementation of greater cost-efficiency and market integration advocated by the EEAG is still pending in many MS, subject to national circumstances affecting design choices yet to be made. The national experiences gained with the introduction of FIP schemes and competitive bidding procedures to date should be disseminated among the MS for learning purposes and for minimising the risks of badly designed schemes.

Competitive procedures for setting levels of RES support are to be preferred in principle

RES support levels can be determined administratively or by a competitive procedure: support schemes based on **administrative procedures** have been very successful in scaling up RES generation throughout Europe. However, they have encountered difficulties in adjusting levels of support in reaction to market developments in a timely manner. Their flaws have been addressed in some MS and they should retain a role in promoting technologies where competitive procedures might be ill suited. **Competitive procedures** are to be preferred, provided an evaluation of a number of parameters defining the bidding process is available in advance. The existence of competitive conditions which is a crucial prerequisite for successful implementation should not be taken for granted.

Quota systems or certificate schemes introduce a market mechanism for setting the value of RES support

While RES targets and penalties are set administratively, they leave certificate markets to settle the premium awarded on top of energy market prices. They expose producers to market risks including balancing responsibilities and market price.

The importance of FIT is fading in favour of more market oriented FIP schemes

Feed-in Tariff (FIT) schemes should be considered for small-scale RES producers only and be designed to ensure that energy is as transparently integrated into the market as that of conventional producers. **Feed-in Premium (FIP)** is an appropriate approach to bring RES gradually as close as possible to real market conditions because it should expose them to market prices and balancing responsibilities: a floating premium — as opposed to a fix one — or the shortening of reference periods for setting the reference market price mitigates market exposure and thus market risks.

Making RES fit for the market is at least a mid-term endeavour for which NRAs can actively contribute

NRAs have the competency of defining e.g. adequate rules to enhance the non-discriminatory market access (e.g. to short term and balancing markets) of RES producers.

1 Introduction & purpose

Renewable Energy Sources: A key part of the present and future energy market

In its energy strategy for 2030, the Commission has clearly reiterated the important role RES will play in the transition towards a more competitive, secure and sustainable energy system. To date, support schemes have been successful in driving the deployment of renewable energy generation throughout Europe, with the current level having reached 26% of electricity generated. Achieving EU's 2030 RES target will require the share of renewables to reach upward of 50% of electricity produced.[1] In turn, as a major source of generation, RES can no longer be supported in isolation of market developments.

Purpose of this report

The Council of European Energy Regulators (CEER) continuously monitors developments in support schemes across the EU and regularly publishes a Status Review of Renewable and Energy Efficiency Support Schemes in Europe. Past editions of the report have solely presented comparative information on support schemes for RES, by technology and type of support instrument. However, this iteration goes beyond a purely fact-based report and includes an overview of design options and focusses on mechanisms that have been implemented to achieve greater cost-efficiency and deeper market integration of RES. Clearly these are issues at the forefront of the European Commission's mind as is consults on a new electricity market design and on a new renewable energy directive for the period after 2020.

Structure of the report

The report is structured as follows:

- Chapter 2 outlines the legal framework governing support schemes and the role played by NRAs in the context of RES support schemes;
- Chapter 3 provides a detailed analysis of the different procedures for determining support levels;
- Chapter 4 then sets out alternative mechanisms to enhance the market integration of RES; and
- Finally chapter 5 looks into the support scheme developments to be expected in the near future.

[1] Launching the public consultation process on a new energy market design, European Commission, July 2015, COM(2015) 340 final, p.3.

2 The legal framework and the role of the National Regulatory Authorities (NRAs)

Purpose

In this chapter we set out the legal framework within which national RES support schemes must be developed and what role NRAs play in this process.

The Guidelines on State Aid for Environmental Protection and Energy

The Guidelines on State Aid for Environmental Protection and Energy (EEAG) apply to environmental protection or energy measures for which State aid under certain conditions may be compatible with the internal market.[2] Among other energy measures, they cover aid for energy from renewable sources. They define the general conditions for investment and operating aid to energy from renewable energy sources and as such set the parameters for designing the key elements of every national RES support scheme.

The guiding principle underlying the conditions defined for RES aid is to incentivise the **market integration of electricity from renewable energy sources** and to pave the way for achieving the RES objective in 2030 in a cost-effective way through market-based instruments, such as **competitive bidding procedures as a way to determine levels of support (see Annex 2)**.

However, the practical implementation of the EEAG's ambitious conditions for market integration and competitive procedures for determining level of RES support is still pending in most MS. As such, the outcome in terms of deeper market integration and greater cost-efficiency of the new European legal framework for RES support cannot be prejudged.

CEER position on the EEAG

CEER welcomes the introduction of revised Guidelines defining the legal framework for the design of national support schemes. This is due to its positive contribution to long term regulatory and investment planning certainty. CEER in particular supports the implicit steer towards greater integration of RES within the market.

The role of National Regulatory Authorities (NRAs) in the design and implementation of RES support schemes

RES support schemes are legally defined in national legislation. While the design of RES support elements falls in the remit of Ministries, other bodies, usually public entities, are often in charge of the implementation of the RES legislation on the ground. Hence, expertise is spread beyond the ministerial sphere and regulators frequently have a central role going far beyond network related issues such as ensuring priority access and dispatch for RES. An internal inquiry carried out among CEER members (see annex 3) brought forward that NRAs' responsibilities in the field of RES support differ and that a majority acts as expert in advising the relevant Ministry and in implementing key elements of RES support schemes such as those exemplarily outlined in table 2 below.

[2] Treaty on the Functioning of the European Union, Article 107(3)(c).

NRA's role	Example of Member States
Overseeing/ managing the FIT scheme and/ or setting the level of FITs	AT, GR, FI, HR, HU, LT, MT
Overseeing financial flows linked to the funding of the RES scheme	DE, FR, SI (in future: ES, HU and GR)
Setting the level of the RES levy/contribution	FR, GR, LU
Overseeing the levy determination process	DE, AT
Running registries of RES installations	AT, DE, GB, SE, SI, LU
Checking the eligibility for exemptions of the funding scheme	FR, HU, LU, NO
Managing the system for the guarantees of origin and disclosure of electricity	AT, ES, HU, LU

Table 1 – Overview of NRAs role

NRAs play an important role in the implementation process of RES support schemes. They should further build on their expertise in the regulatory field to actively address the barriers hindering an effective market integration of RES, such as defining appropriate and non-discriminatory access rules to the short term energy markets as well as the balancing and ancillary services markets. The involvement of NRAs as a neutral party with the relevant expertise in the field of RES could be further strengthened, e.g. for providing critical assessments of their respective national support schemes on a regular basis.

3 Procedures for determining support levels for RES

Purpose

This chapter explores the options for determining support levels and considers the effectiveness of the options and challenges they are likely to pose. A selection of case studies provides further information on ways of designing competitive procedures and certificate schemes.

Options for determining support levels

A fundamental challenge in designing support schemes is how to determine the most cost-efficient level of financial support. This involves a balance between incentivising investment and avoiding overcompensation. In principle, they are three basic approaches for determining support levels, namely **(1) politically, i.e. by the administration, (2) through a competitive process such as tenders or auctions, or (3) through a certificate (quota) scheme.**

Current practice and trends

In the majority of MS, support levels are currently being determined based on an administrative procedure, where different key parameters such as costs of renewable generation and deployment objectives are taken into account to set the level of support. However, administrative processes are increasingly being perceived as inefficient due to the potential for over- or under compensation. As a consequence, competitive procedures, consistent with the requirements of the EEAG, are increasingly being considered or introduced.

3.1 Designing administrative procedures

Support levels set administratively can be described as price-based mechanisms. A public authority sets the price for RES production in order to steer the development of RES, *i.e.* the quantity of new installations, in a way that the true costs of a RES technology are recovered.

3.1.1 Two main approaches applied in administrative procedures

Two main approaches are used to determine the level of support, either through (1) recovering the overall costs of RES installations, or (2) by accounting for the positive externalities of RES, which are not captured by market prices. Both are explaining in detail below.

1. Overall cost of RES production

This approach relates to the concept of the levelized cost of energy (LCOE), which involves calculating the total cost of generating electricity over the lifetime of a power plant. The main parameters that have to be defined are the following:

- **Investment costs (CAPEX)**: These costs typically include project development and permitting, purchasing of power production equipment, construction, grid connection, decommissioning and financing costs (capitalised interests during the construction phase);
- **Operational costs (OPEX)**: Such as fuel, maintenance, insurance, taxes, and market integration (e.g. balancing costs) if applicable;
- **Possible extra revenues:** For instance other forms of support (investment grant, tax reduction), marketing of guarantees of origin or heat;
- **Duration of the support**: It can be based on the depreciation period (e.g. 15 to 20 years), or shorter;
- **Return on capital**: Usually calculated as a weighted average cost of capital (WACC), which takes into account the interest rate of debt and the required return on equity; and
- **Indexation**: Price indexation for example, which would lead to increasing support levels in order to level out future inflation risks.

The level of support is then calculated as the overall cost of production (net of extra revenues), calculated as equal annual payments per output using the estimated weighted average costs of capital (WACC) as a discount rate.

This approach is equivalent to calculating the revenue needed for a specific internal rate of return (IRR) of a RES project over its lifetime where this IRR equals a reference rate of return, typically calculated as the WACC of the RES sector.

Over the last years, support levels based on LCOE have been the most widespread design feature for FIT schemes throughout the EU.

2. *Avoided costs plus externalities*

In this second approach, the level of support would be calculated as the sum of the value of the power production of a RES installation[3] and the value of the externalities linked to electricity generation such as (1) avoided CO2 emissions, (2) security of supply (reduction of fossil fuel import) and (3) improvement in the air quality, since RES are usually not responsible of the emission of pollutants such as NOx, NHS, etc.. Each of these externalities then has to be quantified and monetised to be added to the reference value of the power production installation.

In practice, this calculation has proved difficult, as the parameters used tend to rely on estimates. Moreover, since actual costs of RES are not considered, there is a risk that the level of support determined does not reflect the real costs of RES production, leading to either under- or overcompensation. This is particularly true for the less mature types of RES, since the approach tends to lead to a uniform level of support for all RES. For these reasons, this type of calculation is not commonly used, and most countries resort to the approach based on LCOE, as outlined above.[4]

3. *Additional design features of administrative processes*

Policy makers also tend to consider the following additional features when designing support schemes.

Differentiation of support levels by maturity, technology and/or installation size
RES technologies vary greatly in terms of maturity and competitiveness, leading to cost differentials. Significant cost differences may also be observed, depending on the type of installation (e.g. rooftop PV or ground-mounted PV) or its size, which can result in economies of scale. In terms of cost-efficiency, focusing support only on the most mature and most competitive RES technologies seems a rational approach at a first glance. However, in order to achieve large scale RES deployment, a diverse mix of generation technologies, installation size / capacity and geographical locations is preferable. This can only be triggered through a scheme design based on a mix of different support levels.

Indexation of the support level
In an administrative procedure the support level is determined ex ante for the duration of the support. As a result, it may be necessary to index the level of support over the lifetime of installations, to account for the evolution of fixed OPEX, such as salaries, costs of industrial equipment, as well as variable OPEX, particularly fuel costs in the case of biomass and biogas. Indexation must be properly designed to avoid possible overcompensation and should therefore be limited to the share of OPEX in the overall production costs. The advantage of indexation is the limitation of producers' risks, since their remuneration will automatically adjust to the evolution of their costs (i.e. in both directions). However, some efficiency factors might be imposed to limit price increase. The prerequisite, however, is the existence of a public and robust index which effectively represents costs.

[3] Alternatively, the level of support can be calculated as the avoided production costs of conventional power.
[4] These two approaches can also be mixed. This would be the case for instance in a support scheme based on a LCOE calculation which would integrate a bonus accounting for a specific externality (e.g. waste treatment, fuel efficiency, etc.).

3.1.2 Challenges linked to administratively defined support levels

We now turn to the challenges associated with administratively defined support levels focussing on three particular issues.

1. Asymmetry of information

The main challenge for the public authority is access to relevant and up-to-date information, particularly on investment and operational costs. Absent this information – the risk of under- or overcompensation is significant.

2. Designing support schemes for different types of RES installations

When a support scheme is designed administratively, it has to be kept relatively simple, and therefore must adapt to a wide range of installations. This represents a challenge, since the public authority needs to establish a level of support that will apply uniformly to a variety of projects, which benefit from different technical, locational, economic and financial conditions. This can be met by defining remuneration caps, e.g. limiting the total production that benefits from support to limit the risk of over-compensation for the installations benefiting from the best conditions. There are further options to reflect the specificities of individual plants such as wind-maps[5] or specific metering procedures in which the support level is directly linked to the metered production during the first years of operation[6].

3. Reactivity in adjusting the level of support

Support levels set to cover the overall costs of RES installations need to be regularly adjusted to appropriately reflect cost trends. Otherwise, this leads to a risk of excessive profitability for RES producers as the costs of new installations typically decrease over time because of learning effects and technological improvements. This challenge can be dealt with in different ways, notably by introducing automatic adjustments to support levels based on previously defined parameters such as the evolution of production costs and the deployment trend ("breathing cap"). A central question is whether to adapt the level of support within the support period or whether market developments or other relevant changes should only be reflected whenever new RES installations are taken into operation. In terms of security of investments, it is not recommended to change the level of support in unexpected manners as this would lead to additional investment costs.

If in place, indexation of supports should therefore be predictable. The granted support level defined for a fixed period of time should be calculated to cover the costs of the RES installation throughout its life (support) time. Adjustment rates[7] for support levels defined ex ante or following a deployment trend should be transparent and communicated in a timely manner to ensure a reliable planning for RES investors in terms of expected level of support.

[5] Wind maps are for example used in the Netherlands.
[6] This approach is followed in the German support scheme for wind onshore (a reference yield model).
[7] Adjustments are mainly reductions in the level of support, however increases are also possible, e.g. when deployment paths are not met.

3.1.3 Concluding remarks on administrative processes

CEER believes that while administratively determined RES support schemes have proven to be an effective tool to scale up the deployment of RES, in an environment of decreasing costs and improved competitiveness for RES, they have often been inefficient in terms of reaction time notably resulting in overcompensation for some RES technologies (e.g. PV) along with overshooting the respective targets. These shortcomings have been successfully addressed in some of the MS concerned, where new design options have been introduced (e.g. breathing caps, automatic adjustment factors, etc.).

Despite the described weaknesses linked to administrative procedures and the observed trend towards competitive procedures, CEER believes they will continue to play a role in determining support levels for RES technologies, especially for those technologies where a competitive procedure would not be suited (e.g. whenever a competitive setting is lacking). In those cases, MS should continuously work on enhancing their administrative procedures to ensure cost-efficient support levels.

3.2 Designing competitive procedures for determining RES support levels

Having considered administrative procedures the second part of this chapter turns to competitive procedures. The objective of competitive bidding procedures, such as tenders or auctions, is to determine cost-efficient support levels for RES technologies based on a competitive market outcome. While some MS have already implemented competitive bidding procedures, future national support schemes will have to introduce these following the new EEAG requirements, in which they are set as a default procedure for determining support levels, provided that a competitive environment exists.

Different types of auction/tender designs are possible; all of them require a thorough and consistent design and a sufficient level of competition. In principle, there are two main categories of competitive procedures, which will both be presented in the following chapter:

- **Price-based auctions,** where the bids with the lowest support levels will be accepted; and
- **Multi-criteria auctions**, where the acceptance of a bid is subject to an evaluation of various criteria.

3.2.1 Design options for competitive procedures

The outcome of the auction is a level of support (per kWh) paid to RES producers, which can either be the reference value for the Feed-in Tariff (FIT) or the Feed-in Premium (FIP). Alternatively, it can be the basis of a capacity payment per installed kW, paid out once or on a regular basis.

The set-up of a competitive bidding scheme may vary substantially depending on the political priorities of a MS, the competitive market environment of RES technologies and the legal framework. We consider the following in this section:

1. Eligible technologies: technology neutrality vs. technology specificity
2. The price determination mechanism
3. Price caps
4. Tender volume
5. Frequency of tendering rounds
6. Eligibility criteria
7. Prequalifications
8. Evaluation criteria
9. Penalties
10. Project-related of bidder-related bids
11. Tradability of support entitlements

Design options are not mutually exclusive and can be combined with each other within one bidding scheme.

1. Eligible technology: technology neutrality vs. technology specificity

A bidding procedure can be conceived in such a way that it allows different RES generation technologies to compete against each other, with the aim of determining the most cost-efficient renewable technology. In the EEAG framework, technology neutral procedures are considered as the default bidding scheme, while technology specific tenders would only be allowed under specific conditions, notably a lack of competition or to ensure the diversity of RES technologies.[8]

However, in a **technology neutral bidding procedure**, the choice of the pricing mechanism needs to be thoroughly considered in order to avoid an outcome where the most cost-efficient technology is overcompensated. This could happen in a uniform pricing mechanism (see point 2), where the last bid accepted (i.e. the RES project with the highest generation costs) would determine the support level for all other technologies.

Within a **technology specific bidding scheme***,* a further differentiation of the technology can be a feasible approach for addressing important variations in generation costs[9], the market situation or production site conditions. This option enables the development of various RES technologies at different stages of economic maturity. It can also prevent high concentration of RES installations in the same area (e.g. in the most windy area in the case of onshore wind), which may result, among other things, in increased network constraints. However, it reduces competition within the separated segments.

2. The price determination mechanism: Pay-as-bid vs. uniform pricing

In price-based tenders, where bids are selected in accordance to the lowest possible level of support (price), “**pay-as-bid**” and “**uniform pricing**” are the most commonly used approaches.

[8] MS with high deployment objectives have to incentivise a mix of RES technologies to achieve them and to technically benefit from the variation in production times (wind and solar peaks differ in time; biomass and water production is of reduced weather impact).

[9] In the case of wind power, onshore and offshore wind display important differences in generation costs. For solar power there are different generation technologies such as PV-tracking systems or PV concentrators. Further, the type of PV installation can vary, e.g. it could be a rooftop installation or ground-mounted, etc.

With pay-as-bid, every successful bidder will be entitled to the support level he bids, which is commonly considered as fair. In a uniform pricing approach, the outcome will be a uniform support level for all successful bidders, where the last bid awarded (i.e. the highest bid) determines the support level for every other successful bid (market clearing price).[10]

In a pay-as-bid setting the bidder estimates the value of the last successful bid in order to place his bid marginally below it. This kind of mechanism urges bidders to behave strategically. However, if bidders expect significant competition in an auction, even under a pay-as-bid scheme, they will place their bids at the lowest level they can still afford.

In a uniform pricing setting the bidder has an incentive to reveal his true costs, which is the main reason why this mechanism is generally accepted to deliver the best results in terms of competitive behaviour.[11] Revealing the true costs of a RES project and placing a bid accordingly increases bidders' chances of winning a support entitlement in a uniform pricing setting. Although submitting a bid below the true cost level would further increase this chance, bidders would incur the risk of winning a support entitlement which would be lower than their project's costs. Placing a bid above the true costs reduces the chances for success in the tender even though the RES project could have been realised with a lower support level.

Underbidding, i.e. bidders place bids below their real costs, is a strategic behaviour that can occur in both pricing mechanism.

Further, both pricing mechanism can be combined within one tender, where for example the first round would reveal a uniform price that would subsequently be the maximum price in a second pay-as-bid round. [12]

3. Price caps: setting maximum and/or minimum tender prices

The party implementing a competitive bidding procedure faces some risks in relation to the final outcome, for example the risk of overcompensation in a setting where competition is limited. This type of risk can be mitigated by determining a maximum price (support level) for the auction. However, bidders could use such a maximum price as a guide and bid at or close to it, although this risk is minimised in tendering procedures with intense competition. Further, setting the maximum price too low could also harm competition, as bidders would be discouraged from participating in the tender.

Another risk jeopardising the outcome of a tendering procedure is known as “underbidding” or “winner’s curse”, which basically means that in order to win, a bidder would bid below his true costs, resulting into low realisation rates and underachievement of the deployment objectives. Setting a minimum price for the tender would be one option for reducing such a risk.

[10] This mirrors the pricing mechanism on exchange markets.

[11] In theory both mechanisms lead to the same results - as far as there is strong competition and perfect foresight of bidders. Both aspects can be questioned in real tenders.

[12] This approach has been implemented in Brazil. See Electricity auctions - An overview of efficient practices, The World Bank, 2011.

4. Determining the tender volume

Ensuring a sufficient demand for support entitlements is a key prerequisite for a successful tendered outcome. One of the main determining factors for competition is the volume of support entitlements being tendered. This should be directly linked to the national RES targets. However, there should be an additional evaluation of the expected demand for those support entitlements, in order to adjust the optimal tender size, if necessary.

In situations where demand for support entitlements would not meet the size of the tender, the cost-efficient allocation is jeopardised by this lack of competition. In this case, a reduction of the tender size can be an option.

5. Periodic vs. non-periodic calls for tender

A tender may be executed on a regular basis or on an ad hoc basis, which can have a considerable impact on its outcome. Basically, the higher the number of bidding rounds per year, the more strategic bidding options are available to the bidder and the lower the level of competition in each round. On the other hand, irregular/few bidding rounds increase bidder's risks and can lead to a “disruptive development”, where e.g. project firms go bankrupt when being unsuccessful in a round.

6. Eligibility criteria

It may be of interest to limit support entitlements to specific projects, making a clear definition of the eligibility criteria for participation in the tender necessary. For example, there may be a political necessity to exclude certain locations from participating in a tender, like the exclusion of farmland from a PV ground-mounted auction. Or, in order to increase the chances of success of small sized projects, the maximum project size may be limited.

It is important to notice that by definition any eligibility criterion, that restricts the participation of potential projects, will decrease the level of competition and as such be a limiting factor for a cost-efficient allocation of support entitlements.

7. Material vs. financial prequalifications

In order to ensure the genuine intention of a bidder to realise a project, a competitive bidding procedure has to incorporate prequalification requirements aiming at minimising the risk of speculative behaviour and increasing the chances for finalising the projects. There are two main types of prequalification requirements, “material” and “financial” prequalifications.

The aim of material prequalifications (MP) is to provide relevant information about the development status of submitted projects. They are linked to project-related bids (see point 10). Main disadvantages are the related risks of sunk costs whenever a bid is not accepted and the administrative burden for checking and validating them.

The purpose of **financial prequalifications (FP)** is to get a financial guarantee (bid-bond) for the bidder's creditworthiness and intention to realise his project when successful in the tender.[13] It may be payable by all participants before the tender is carried out or only by the winners after a tendering round, or both. Setting the right level of the FP is challenging: If the guarantee is too low, speculative behaviour will be likely, while if it is too high, some bidders might be discouraged. In both cases, the outcome is jeopardised, either by a low level of realisation rate or a low level of competition.

In terms of implementation, FP are easier to administer than MP. They offer a greater level of flexibility for bidders as they are not necessarily project-related but rather bidder-related. Finally, a FP will serve as a mean to ensure the possible payment of a fine/penalty if, for example, a project is not realised. When considering technology neutral tenders, FP may be more appropriate as different technologies have different licensing criteria/ material prequalification requirements.

8. Evaluation criteria for bids

Selecting the successful bids in a tender may be based on various criteria. Most intuitively, as one of the intentions of introducing competitive procedures for determining the support level of RES is to bring down support costs, the price offered gives a straightforward indicator and can be defined as the reference value for a FIP, a FIT or a capacity payment per installed kW. Such tenders are single-criterion tenders.

However, also other aspects of a bid may be of relevance to the implementing authority, which could be defined in a catalogue of evaluation criteria. This catalogue should include a weighting system determining the evaluation criteria ex-ante and in a transparent manner. A number of different evaluation criteria are conceivable, such as local content assessment, environmental impact analysis or specific technological features.

In a multi-criteria tender, evaluating the bids and selecting successful bids become a much more demanding task for the implementing authority. In addition, this tendering approach bears a greater risk of diverting the focus from determining cost-efficient support levels to other non RES- related objectives (e.g. securing local employment, etc.).

9. Penalties

A competitive bidding procedure usually includes a penalty scheme in order to increase the realisation rate. For example, failing to realise a project as a successful bidder, a delay in the predefined realisation time, and a deviation from the agreed upon specifications of the installation would induce a penalty. This penalty is usually a predefined amount of money. Other possible penalties could be the temporary or the permanent exclusion of a bidder from future tendering rounds (necessity of bidder registry), higher prequalification measures for the future, a reduction of support levels or a shorter support period. In any case, each penalty type has positive aspects and limitations.

[13] The financial guarantee can be provided in the form of a bank guarantee or through a direct payment to the implementing party.

The fine should not be set too high as to deter potential bidders but should exercise an appropriate level of pressure to ensure realisation of the project. The question of who is responsible for the failure of a bidder to realise a project should be avoided. Such questions could lead to lengthy legal disputes and could result into very low realisation rates. Therefore, penalties should optimally be applied regardless of the reason causing the delay.

Penalties can be combined with a corresponding financial guarantee (see above). Thus, if a bidder fails to pay the fine, the guarantee can be used to satisfy the claim.

In case of long realisation periods bidders may count on falling costs to outweigh the possible penalty payments due in case of delay. Shorter realisation periods and high penalties may solve this problem, though reducing the number of bidders. In fact, the absence of penalties has shown to lead to underbidding and to poorer realisation rates.[14]

10. Project-related or bidder-related procedure

This design option clarifies whether a support entitlement is connected to a specific project or to a successful bidder as a person or legal entity. A project specific support entitlement would lose its value whenever the project itself has become deadlocked, whereas a bidder-related support entitlement could always be transferred to another project within a bidder's portfolio. Bidder-related entitlements might as well be tradable.

While a project-related setup allows the implementing party to gain valuable information on the various specific projects and ensures that the bidder is in fact participating in a tender with a concrete project and not for speculation, it also substantially reduces the flexibility of the bidder. This flexibility loss, i.e. the prevention to use the support entitlement for another project, whenever the initial project fails to be completed for whatever reason, has a direct negative impact on the realisation rate. On the other hand, project-related procedures may tend to show a high realisation rate when bidders have to demonstrate a well-advanced project status. This in turn increases the costs which bidders have to bear upfront and increases the risk of sunk costs.

11. Tradability of support entitlements (secondary market)

The tradability of support entitlements on secondary markets after they have been awarded to the successful bidders is another dimension of bidding schemes, which needs to be addressed in the design phase. A well-functioning secondary market for support entitlements may help to achieve higher realisation rates, a high level of competitiveness in a tender and a maximum level of flexibility for the bidder. The realisation rate can be further increased, when a successful bidder, seeing the realisation of his project at risk, has the right to sell his support entitlement to a third party, which would complete another RES project (for which it did not win a support entitlement).

The competitiveness in a tendering round may increase because the risk for a bidder to bear sunk costs is decreased by the option to sell the support entitlement. However, tradability of support entitlements may also increase the risk of speculative behaviour, where in the end bidders participate in a tendering round without any intention of realising a RES project. So far there is no experience with easily tradable support entitlements.

[14] See section 5.4.2.

Competitive bidding procedures (call for tenders) in France

Well before the adoption of the EEAG, France had already put in place in 2000 a legislative framework for awarding support to RES installations based on a competitive procedure, according to which the government may decide the launch of a call for tenders when installed capacities do not meet national objectives.

Basic functionality

Calls for tenders in France can be described as pay-as-bid, project-related auctions, which are applied on a technology specific basis. The tender specifications define a set of eligibility criteria as well as selection criteria. Successful candidates are awarded a power purchase agreement, at the price they proposed in their bid. Penalties may be applied by the government if a bidder does not meet its obligations, such as deadline for the realisation of the project.

The procedure itself, in particular the assessment of submitted bids, is implemented by the French regulator (CRE - Commission de régulation de l'énergie), before the government designates the winners.

Calls for tenders have so far been applied 14 times for RES support, mainly for biomass, PV and offshore wind installations. The examples of PV and offshore wind tenders are described in more details in Annex 4.

Key lessons learnt

The main conclusions that can be drawn from this case study are the following:

- **Cost efficiency**: Calls for tenders can be a cost-efficient way of allocating support of RES installations, when sufficient competition occurs. This is particularly shown through the example of medium and large scale PV in France, which has been supported by calls for tenders for several years, and for which the level of support for new installations has dramatically decreased;
- **Coexistence of multiple support schemes**: The existence of multiple support schemes - tariffs and tenders for instance - for the same type of RES installations is on the contrary highly inefficient, since it leads RES producers to choose the most profitable one, to the detriment of the cost of support; and
- **Design of the tender parameter**: The tender parameters, regarding e.g. selection criteria or lead-time for submitting bids, can have a significant impact on the competitive level of the tender and its results and must therefore be carefully designed in order to achieve highest cost-efficiency.

3.2.2 Challenges in designing competitive support schemes

Having set out the various design questions policy makers must grapple with, we now look at the most significant challenges.

1. Ensuring competition

The main challenge posed by any tendering scheme is to ensure sufficient competition. The success of an auction in determining a cost-efficient support level depends on an excess demand for support entitlements.

Thus, there is a necessity to evaluate the market before implementing the auction design. This could be done through an exhaustive market analysis[15], which may include an assessment of available sites, interviews of market participants, country comparisons, and workshops with potential bidders. Alternatively, the implementation of small pilot tenders allowing for a "reality check" of various design features may be envisaged.[16] However, if competition for support entitlements cannot be expected, a competitive bidding procedure may be an inappropriate instrument for determining the level of support and therefore should not be implemented.

2. Ensuring investor confidence

In addition to a competitive environment, another key challenge is to keep investors' risks as low as possible to achieve the objective of reducing the overall level of support. In fact, the participation in a tendering procedure with an uncertain outcome increases bidders' risks in comparison to an administratively fixed support. Indeed, tendering schemes are always linked to more responsibilities and risks for RES investors (i.e. bidders): They have to provide material and/or financial prequalifications. They are subject to realisation deadlines and penalty payments in case of non-delivery and, in the case of an unsuccessful participation, sunk costs. These increased risks will be incorporated in the bid and can potentially lead to an increase in the level of support. Equally, a lack of competition, can lead to higher support levels.

3. Other challenges

Finally, when designing an auction, a number of other challenges need to be considered, such as (1) avoiding strategic bidding, (2) achieving high realisation rates without discouraging potential (smaller) bidders to participate, and (3) ensuring diversity of bidders (investment companies, energy suppliers, project firms, private investors) as a potential important aspect for public acceptance.

[15] Such market analysis procedures are mandatory in European telecommunication markets in the case of frequency tendering to ensure a competitive setting is given before being implemented.
[16] For a transitional period until 2017, this would also be in line with the EEAG, where a 5 % tendering volume is foreseen for the years 2015-2016.

3.2.3 Concluding remarks on competitive procedures

Competitive bidding schemes have a range of advantages linked to their potentially quick reactivity to cost and price reductions or other relevant market changes compared to administrative procedures. Furthermore, they do bear the potential of bringing down support costs, as demonstrated in some MS.

However, a cost-efficient outcome will depend on the existence and interaction of different factors (e.g. competitive situation, deployment objectives, etc.). The process of setting up an appropriate auction design may prove to be very complex as it requires to reflect multiple parameters (e.g. scope of tender, awarding mechanism, selection criteria, type of prequalification, price limits, realisation time, etc.), and needs to be very well thought through. As such, changes to the parameters of the tendering procedure should as much as possible be avoided to ensure security of investments.

A design process might also conclude that a competitive bidding scheme cannot be implemented for a specific RES technology and as such should not be introduced, which would also be in line with the EEAG provisions.

3.3 Green certificates or quota support schemes

We now turn to green certificate schemes. A green certificate scheme is a support mechanism designed to provide specific RES technologies with an additional income to the market revenue by selling previously awarded certificates to an obliged party. It is a volume-driven support mechanism with a particular renewable target, usually set as a RES-share in final consumption or explicitly in volume of produced electricity. Currently six MS (see Annex 5) and Norway have introduced such a RES support mechanism. However, in Italy, UK, and Poland, quota systems are now being replaced by other types of support schemes, notably FIP.

Within the scheme, market participants (typically suppliers and producers or grid operators) are given a statutory duty to annually buy and cancel electricity certificates. The number of certificates that one is obliged to buy corresponds to the value of the mandatory renewable quota established for the current year, multiplied by the quantity of electricity (expressed in MWh) supplied annually to the final consumers. This will create a demand for certificates. Producers that receive certificates will earn an income from selling certificates, in addition to the income they receive from the sale of electricity. This is intended to make it profitable for investors to invest in new electricity generation from renewable energy sources.

An electricity certificate system is a market-based support mechanism. Different variations of electricity certificate schemes exist. Most countries opted for an electricity certificate scheme national in scope whilst Norway and Sweden have a common certificate system in place.

3.3.1 Design options for green certificate schemes

The design of a quota system may vary depending on the overall objective of the system. Common to all quota systems is that the level of support is determined by demand and supply. Some MS also apply hybrid systems, e.g. a quota with minimum prices. An overview of the alternative design options implemented in the MS is provided in Annex 5.

This section provides an overview of some of the different issues that one needs to bear in mind when designing a quota system. This includes how the overall objective is set, who is made eligible for receiving and for buying certificates, and how the penalty mechanism can look like.

1. Overall objective

Similar to all RES support mechanisms, quota schemes follow the objective of increasing the level of electricity production from renewable energy. The focus is on a market based approach, where certificate prices are determined by the interplay of demand and supply for certificates.

2. Eligibility of certificates

Quota schemes can in principle be designed to be technology neutral or technology specific. In a technology neutral setting, each RES technology covered by the scheme would be awarded the same amount of certificates per MWh generated and as such receive the same support level regardless of technology costs. Under this scheme, the most cost efficient plants would be realised first. In terms of design, this is the most straightforward approach requiring only defining the scope of RES technologies to be endowed with certificates.

More complex in terms of design are technology specific quota schemes. By setting different multiplier for the volume of certificates awarded for each MWh produced depending on the generation technology, MS can ensure that a variety of technologies is supported within the quota scheme, e.g. by issuing immature technologies a higher number of certificates for each MWh produced compared to more mature technologies. However, in practice an enduring volume weighted approach is made particularly difficult by the changing landscape of technological advancements and efficiency improvements in a number of RES technologies.

A RES power plant receives electricity certificates for a specific period of time (number of years can vary).

3. Buyers of certificates

The number of buyers of certificates may also differ from system to system. Some countries have chosen to link the obligation to purchase certificates to the electricity suppliers. Other countries have chosen to link the obligation to purchase certificates to grid operators.

4. Penalty mechanisms

In order to ensure a demand for certificates there must be a penalty mechanism in place when not meeting the legally required number of certificates each year. In other words, the cost of failing to meet the legal obligation to purchase certificates must be higher than the market price for certificates. Most countries have an administratively set rule on how to determine the level of penalty. It is usually either set annually or as a fixed price level. Similar to a tendering scheme, the level of penalty needs to be well designed to exercise the right amount of pressure to ensure compliance.

The UK Renewables Obligation (RO)

In 2002 the UK Government replaced the Non-Fossil Fuel Obligation with the Renewables Obligation (RO). The RO was designed to better address the need for a greater share of electricity to be generated from renewable sources than its predecessor. For over a decade, this green certificate quota scheme was the primary mechanism for supporting large scale renewable generation. Although the emergence of new challenges in the UK energy sector has prompted the transition from the RO to a new support scheme (see Annex 8 for details) – the RO effectively has achieved its objective of increasing the share of RES generation. For example, in 2002, the UK possessed approximately 3GW of installed renewable capacity; according to Government statistics, as of Q1 2015 this figure exceeded 26 GW.[17]

Basic functionality

Renewable Obligation Certificates (ROCs) are green certificates issued to operators of accredited renewable generating stations for the eligible renewable electricity they generate. Operators can trade ROCs with other parties. ROCs are ultimately used by suppliers to demonstrate that they have met their obligation. Where suppliers do not present a sufficient number of ROCs to meet their obligation in a given year, they must pay an equivalent amount into a buy-out fund. The administration cost of the scheme is recovered from this fund and the rest is distributed back to suppliers in proportion to the number of ROCs it has accumulated.[18]

Key lessons learnt

The RO has fulfilled its intended outcome of facilitating an increased share of renewable generation. Despite this significant increase in renewable capacity, it was no longer compatible with the UK Government's aim of supporting low carbon technologies in the most cost effective way, and maximising investment certainty. The incompatibility of the RO with this aim was due to a number of factors:

- **Value for money**: Since 2009, the RO has operated under a banding mechanism where a ROC / MWh ratio is determined for each technology (before this all technologies received one ROC/MWh). This created a level playing field for acquiring investment across technologies, but limited incentives for more expensive technologies to reduce costs and compete directly with different RES generation technologies.

- **Investment uncertainty**: Under the RO scheme, a generator's revenue is ultimately dependent on the price it can sell its electrical output (and its ability to sell this output), and the price of ROCs. Due to volatility in both electricity and ROC markets, their future prices are uncertain, meaning future revenues are uncertain. Generators assume the risk of fluctuations in electricity / ROC prices such that if electricity / ROC prices go down, revenues go down (and vice versa). This risk and degree of

[17] https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/437810/Renewables.pdf
[18] https://www.ofgem.gov.uk/environmental-programmes/renewables-obligation-ro

uncertainty about future prices increase the borrowing costs faced by investors to fund the project, a cost which is ultimately passed onto consumers.

- **Security of supply**: A stable investment environment for RES investment is key to delivering additional renewable capacity, and ensuring adequate security of supply. The limited scope for revenue certainty under the RO scheme may have implications for security of supply. A significant number of conventional plants are scheduled to close in the UK between 2015 and 2020, largely attributable to stricter environmental regulations and increased competition from low-carbon generators[19]. A support scheme which provides a greater degree of revenue certainty may promote a more attractive investment environment and help mitigate the risk to supply security through additional RES.

- **Project financing**: Under the RO scheme, generators are unable to gain accreditation until the project has been commissioned. This requirement limits the scope for providing financing assistance to projects in earlier stages of development.

The way forward

Against the changing social and political landscape[20], the UK Government concluded that a new approach to RES support was necessary. From 31st March 2017, the RO subsidy will be closed to new capacity[21]. Until this date, the scheme will co-exist with the Contract for Difference (CfD) support schemes (see Annex 8), providing renewable generators with a one off choice between the RO or CfD support schemes. All projects already under the RO scheme before this date will remain in the RO until the original period of support expires, or until 31 March 2037, whichever is earlier.

3.3.2 Challenges in designing certificate schemes

Quota schemes face two types of challenges: (1) likely windfall profits for lower-cost technologies in the case of technology neutral settings and (2) regulatory risk as changes to the regulatory framework affect the market for certificates, which creates uncertainties for investors and can lead to higher capital costs.

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[19] This includes over 11.5GW of conventional capacity that has closed (or is scheduled to close) from 2012-2015 under the Large Plant Combustion Directive (http://www.nationalgrid.com/NR/rdonlyres/DD31ED99-F769-4995-84E3-809E29CE2E19/19877/pp07_32_LCPD_revised.pdf).

[20] In recent years, new challenges have emerged in the UK energy sector. Greater scrutiny has been placed on the amount of compensation awarded to RES generators under the current support framework, alongside growing public pressure for more affordable energy.

[21] Subsidies under the RO for onshore wind will close to new capacity from 31st March 2016.

The risk of windfall profits can be addressed by introducing technology specific features, such as technology banding, where the number of certificates awarded for different technologies varies in accordance to their relative cost advantage with the use of appropriate multipliers (e.g. in Romania, UK, Italy). This technology-specific approach however leads to an additional layer of complexity for the certificate market and complicates the predictability of the certificate price for investors, leading to additional costs. Further, defining multipliers for the different technologies requires an in-depth knowledge of the technologies' costs. Alternatively, separate certificate markets for each technology would facilitate the predictability of the certificate price but reduce the competitive setting.

The risks linked to uncertain certificate and electricity prices developments increase the cost of capital and hence the cost of the support scheme. It may constrain investment to larger companies which are best able to manage this risk. These risks can be mitigated by e.g. concluding long term contracts and by introducing floor prices.[22] Perceived risks linked to the regulatory framework can increase the cost of capital. A quota scheme is a politically constructed instrument, and changes to the rules governing the market can have a direct bearing on the support received at any time. In order to mitigate this risk the rules should be designed to be as predictable as possible and changes or adjustments should be planned and thoroughly assessed.

The Norwegian/ Swedish electricity certificate system

Since 1 January 2012, Norway and Sweden have had a joint market for electricity certificates. This is based on the Swedish electricity certificate market, which existed since 2003. Together with Sweden, Norway's goal is to develop new power production based on RES corresponding to 26.4 TWh by the end of 2020. Each of the two countries will finance half of RES production, but it is up to the market to decide where and when the new production will take place.

Basic functionality

The support scheme is technology neutral, which implies that all new RES installations, regardless of technology, built after 2012 receive one electricity certificate for each MWh produced.

Key lessons learnt

The following conclusions can be derived from the case study:

- A technology neutral quota scheme can be a cost effective instrument of introducing new production capacity, given that investors have good information about the investment cost of other investors (their competitors).
- In the electricity certificate system, markets have developed to hedge both electricity certificate price and the power price. In other words, a producer can secure its long-term revenue streams through market instruments. The system is designed in such a way that the decision to secure a revenue stream is left to the producer. However, banks and other financial institutions have pointed out that

[22] For more information about the design feature and challenges of quota systems see "Design features of support schemes for renewable electricity", Ecofys, 2014, p.74 et seq.

efforts should be taken to increase the liquidity further in these futures markets.

- The two countries have established a framework where any changes should be limited to periodic reviews that usually occur every fourth year in order to mitigate the regulatory risk.

The way forward

The common Swedish and Norwegian electricity certificate market have by the 3rd quarter 2015 built 12.9 TWh of new renewable electricity production capacity since 2012. This is in line with the set trajectory to introduce 26.4 TWh by 2020. Norway and Sweden have predefined progress reviews. Under the current progress review (2^{nd}) the two governments are assessing the possibilities of extending the electricity certificate system. They are specifically reviewing the technical adjustments needed in the case of just one country extending within the electricity certificate system.

A comprehensive description of the Norwegian Swedish certificate scheme is provided in annex 6.

3.3.3 Concluding remarks on quota schemes

Quota systems have been introduced by a few MS and Norway to incentivise the development of RES. CEER believes that under certain conditions it is an effective market based mechanism to support RES, as demonstrated by the Norwegian-Swedish quota system. It seems technology neutral support schemes are best suited for countries whose main priority is to increase the level of renewable production, where the type of new production is a secondary concern.

4 Integrating RES into markets

Purpose

As we mentioned in the introduction, the increasing share of RES in the electricity system is leading to a discussion about the way RES has been supported to date and the extent to which that supports broader objectives for creating competitive electricity markets. Renewable based electricity needs to be integrated as best as possible into the market to keep the distortive effect of support to a minimum and achieve an internal market with price signals reflecting real market conditions. This section considers ways to achieve these two objectives.

Options for bringing RES into the market

RES producers falling under a FIT scheme do not react to market conditions. However, increasing shares of RES electricity influence the power market and so it becomes more and more important to integrate RES producers into the market by exposing them to short term price signals. In order to best realise this potential, liquid short term markets (day ahead and intraday) are prerequisites. On the other hand, liquid short term markets will develop anyway once significant volumes of RES generation start to be integrated into the market, especially induced by the vital need of intermittent RES generation for very short term products (e.g. 15

minutes) and tradeable until the latest moment possible (e.g. 30 minutes ahead of delivery), when forecasts are the most reliable.

In the long run, market integration of RES also means that investment in RES production should be driven by market prices. As for now, since RES production is still more expensive than conventional production, RES investments remain mainly driven by subsidies. However, this situation is expected to change for a number of reasons, such as:

- The continuous reduction of RES production costs;
- The normalisation in conventional power markets (shut down of conventional power plants) and thus recovery of market prices; and
- The growing internalisation of external costs, e.g. greenhouse gases.

Growing shares of RES production also have some major impact on the electrical system, such as merit order effect (renewables with close to zero marginal costs tend to lower market clearing price and phase out producers with high marginal costs) and increase in the need for flexibility (due to intermittent generation). Another impact is linked to the priority dispatch of RES production, which may have to be reconsidered in the light of operational problems in the system and its overall efficiency. These issues are however beyond the scope of this paper, and are therefore not further addressed here.

With this long term objective in mind, the following chapter will look into the ways support schemes (FIT and FIP) can be conceived to incentivise the short term market integration of electricity from RES at the level of individual installations.

4.1 Market integration through Feed-in Tariffs (FITs)

Traditionally, FIT schemes have been used to promote the deployment of RES on a larger scale by ensuring a largely risk-free environment for RES plant operators. Under this framework, RES electricity was fed into the grid regardless of market signals. This is referred to as the “produce and forget” feature of FIT schemes.

Market integration is not a predominant feature of FIT scheme. However, the choice of design options can at least ensure some minimum levels of market integration.

4.1.1 Design options for FITs

FIT can be designed in such a way, that all RES electricity produced under this scheme is collected by an independent entity, which would place it in the market. This function can be played by any independent third party, having the relevant skills and financial means to deal with the market risks (e.g. balancing) linked to the sales of large quantities of intermittent electricity. In some MS (e.g. in Germany) it is the TSO that is taking on this role. Although price signals will not have an effect on the production pattern of RES producers, they do influence the market outcome as the electricity is integrated in the short term market.

In the above described system, incentives such as yearly bonus could be introduced to motivate the entrusted entity to make the best possible forecasts to maximise sales by minimising additional balancing costs derived from inaccurate forecasts. With those design features, a non-market based instrument such as a FIT scheme could also contribute to the integration of RES into the market, though in a very limited (and centralised) way. This can have some relevance to the future design of RES schemes, as FIT could remain in place for smaller RES producers and possibly for already active producers.

FITs can also transmit to some extent an incentive for RES producers to adapt their production pattern to the needs of the electrical system, for instance through a differentiation of their support tariff according to the time of the year.

Examples of national approaches to market integration under FIT schemes

In **France**, the incumbent supplier (EDF) is the main administrator of the FIT system, purchasing electricity from RES suppliers. From 2016 onwards, the purchased electricity will be partly sold by EDF on the spot market, and partly sold through future contracts. Moreover, some FITs for hydropower include a differentiation of the tariff level according to the time of the day/year, with four different options: summer/winter and peak/off-peak.

Austria has a central entity (OeMAG) which manages all electricity from supported renewables. Suppliers are obliged to buy this electricity from OeMAG (regarding to their share in final consumption) at the day-ahead spot market hourly price. In case of a negative price the electricity is allocated at 1 cent/MWh.

In **Hungary** FITs are differentiated according to the time of the day/week. This “imitates” market signals on a general and basic level. It does not reflect actual market conditions but it can reflect the usual supply/demand situation. Hungarian feed-in-tariffs have three time zones: peak, valley and deep valley.[23] It does not apply for intermittent generation (wind and sun). Experience shows that biogas and biomass (including co-firing) producers really change their production pattern and run their plants on 50% capacity or stop production entirely during the deep valley period. FIT producers sell their electricity to the TSO, which then allocates the baseload part to the balance perimeter responsible parties (mainly traders) in proportion of the electricity consumption in their balancing perimeter[24] and sells the remaining part on HUPX day-ahead market. It is planned that the TSO will sell the full amount on the HUPX in the near future. An intraday market is also planned to be introduced on HUPX, and in this case the TSO will sell RES electricity on this market as well.

In **Germany,** the four TSOs are responsible for collecting RES sourced electricity falling under the FIT scheme and are obliged to sell it on the spot market. They do bear the full balancing responsibility for this volume of RES electricity fed into the grid. In order to incentivise TSOs to maximise their revenues stemming from their RES selling activities, they are entitled to a yearly bonus if their forecasts deviate as least as possible from the real RES production pattern, i.e. balancing costs are minimised.[25] The TSOs which are also in charge of administrating the RES surcharge account, will deduct the revenues achieved on the spot market from the overall costs linked to the total support entitlements (FIT & FIP) paid out to

[23] It is also worth mentioning that the time periods are a little bit different regionally in order to reduce the sudden change when shifting time zone.
[24] Consumption eligible for universal supply is not taken into account.
[25] See footnote 9.

the DSOs (which pay them out to the RES producers). With this approach, all RES sourced electricity is integrated into the market, however TSOs have no possibility to steer RES generation at the installation level. Thus, RES producers do not react to price signals, seriously limiting the market integrative effect of FIT schemes.

4.1.2 Concluding remarks on the adequacy of FIT for RES market integration

FIT schemes exhibit only a limited potential for market integration. However, FIT schemes can be designed to at least ensure that all RES generation is sold in the market whereby one entity is made responsible for possible imbalances.

CEER favours the use of FIT schemes for smaller scale RES producers and recommends a design addressing the limited market integration of RES as best as possible, e.g. by placing all RES electricity on the market and by introducing time differentiated FITs for steerable RES installations. However, deeper market integration is only achievable in the framework of FIP schemes or quota systems as outlined in the following chapters.

4.2 Market integration through Feed-in Premium (FIP)

In a feed-in premium system, renewable power producers sell their electricity directly on the power market, for which they get the electricity market price and a premium as a support element on top of it. As a result, there is an incentive, especially for non-intermittent RES units (e.g. biomass, biogas, or hydro), to react to some degree to short term market signals. Having the same balancing responsibilities as all market players is also very important for short term market integration. In this case RES producers are incentivised to keep their schedule by selling or buying on the short term markets instead of paying the possibly higher cost of balancing energy.

In the following chapter, the key design options for FIP schemes are presented, as well as the challenges they bring. Two case studies provide a deeper insight on the functioning and the design option of such schemes in practice.

4.2.1 Design options in FIP schemes

Currently, 10 MS have introduced FIP as a way of supporting RES producers. However, as shown in Annex 7, the design options can differ greatly between the different schemes. The main design parameter for a FIP scheme is the choice of the premium, for which a range of possibilities exists (fix, floating, cap or a floor), which fundamentally affects the risk transferred to the RES producers.

1. Different types of premium

a) Fix premium

The basic option is to add a **fix premium** (as shown is figure 1) on top of the market prices. This type of premium results in a high level of certainty regarding the amount of public support, because it is set in advance for the duration of the support. In return, the risk borne by RES producers is relatively high, because their total revenue is directly dependent on the evolution of power prices over the long term (since support is usually granted for 15 to 20 years). Consequently, the WACC of RES projects can be substantially higher than in a FIT system, leading, especially for capital-intensive RES technologies, to higher financing costs.

On the other hand, if market prices are higher than expected in the longer term, this design feature is also unfavourable for the rate-payers because the level of support will turn out to be higher than needed for a reasonable return. This form of fix premium is not common in MS's FIP schemes (see annex 7).

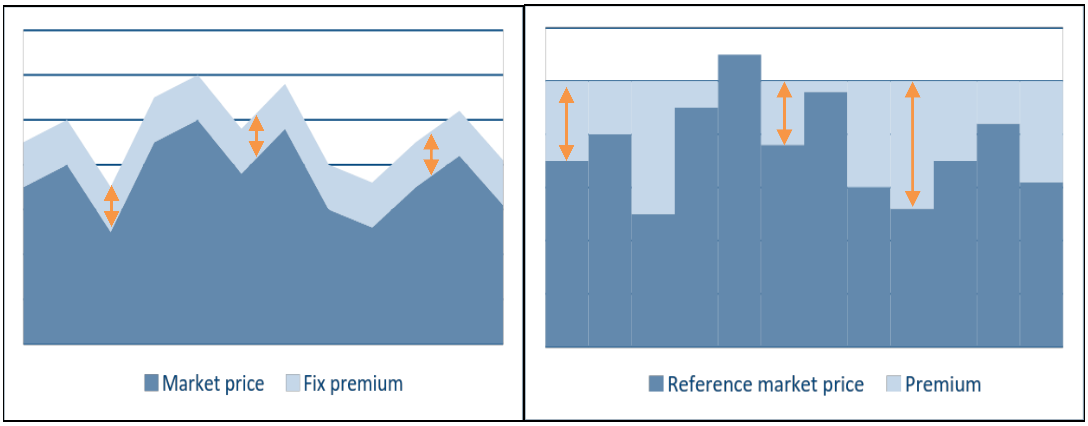


Figure 1: Functionality of fix & floating premia

b) Floating premium

In case of a floating premium, a *reference value (or strike price)* [EUR/MWh] is set and the *premium* [EUR/MWh] is calculated as the difference between the reference value and the ***reference market price***. The reference value can be set administratively (see chapter 3.1) or through a competitive procedure (see chapter 3.2). Whenever the reference market price is above the reference value, the premium would be negative. For this rather unlikely situation, the design can foresee that producers have to pay back this difference (e.g. in UK under the CfD scheme, see annex 8) or the premium is set to zero (e.g. Germany). The introduction of negative premiums (repayment by the producer) can reduce the needed support, when using it for technologies close to market parity (reference value close to expected market price) or if market prices go up unexpectedly.

The choice of the reference market price should reflect the available market revenue for producers. It is usually linked to a relevant energy exchange price. Further, the timeframe defined for the reference market price is crucial regarding the exposure of RES producers to market signals and risks:

- **Hourly fixed reference market prices:** The incentive for market integration is basically removed. The producer is interested in finding a better price for that given hour but not interested in scheduling its production according to different prices for different hours. Therefore, the market integration effect of hourly set premiums is equivalent to FIT.

- **Monthly (or longer) fixed reference market prices:** Producers are incentivised to perform better than the average market outcome. The longer the fixed period, the greater the incentive for market integration. If fixed e.g. for one year, producers are incentivised to optimise their output (or sales) across months and seasons. However, the lengthier the timeframe, the higher the risks for the RES producers. Consequently, setting the reference period is a trade-off between achieving higher levels of market integration and transferring a bearable share of risks to the RES producers. In practice, MS have opted for different timeframes, for example a yearly period in the NL, a six-month period for baseload RES generation in the UK, a monthly period in Germany and an hourly basis for some RES technologies in the UK.

In general an average market price (e.g. an arithmetic average of hourly spot prices) is typically used as reference market value. For intermittent generation (e.g. wind and PV) however, the average market spot price should be weighted with actual production profiles in order to more appropriately reflect real commercialisation opportunities[26]. RES producers can achieve higher revenues whenever they perform better than the market average. This presupposes the successful adaptation of the production pattern to market signals and the additional revenue being high enough to cover the extra costs needed to provide this flexibility (e.g. adjusted technology, appropriate steering decisions, storage, increased capacity, etc.).

The reference price can be set ***ex ante or ex post***. Ex ante setting is based on forward prices, while ex post version is typically made by averaging hourly spot prices. Ex ante price setting gives more predictability ahead for the producers, while possibly lowering incentives for risk-averse producers to react to short term market signals as the market outcome is not properly reflected. The risk for over or under compensation is especially relevant in a setting where ex ante reference prices are technology-specific. Ex post price setting provides less predictability and by this stimulates more flexibility as risk-averse producers would sell their electricity as best as possible on the day ahead and intraday markets.

In a floating premium scheme, the long term revenue of RES producers is guaranteed, but the amount of support to be paid out (and to be refinanced by consumers) is difficult to predict as it depends on the reference market price. Although this might be seen as an issue at the political level and in terms of public acceptance, in practice, floating premiums are mostly used in MS' FIP schemes.

[26] For instance in the case of PV, the weighting may reflect the specific production pattern (daytime only) of this technology.

(c) Caps and Floors

Introducing caps and floors are instruments to accommodate the advantages and drawbacks of fix premium and floating premium schemes. ***A fix premium scheme*** bears the risk, that the agreed premium will be too low or too high depending on the fluctuation of the market prices. This risk can be shared between the rate-payers and the RES-producers by applying caps and floors to the total revenue, i.e. **the sum of the (reference) market price and the premium.** Basically this means using fix premium while market prices are inside a “tolerance zone” and using a kind of floating premium otherwise.

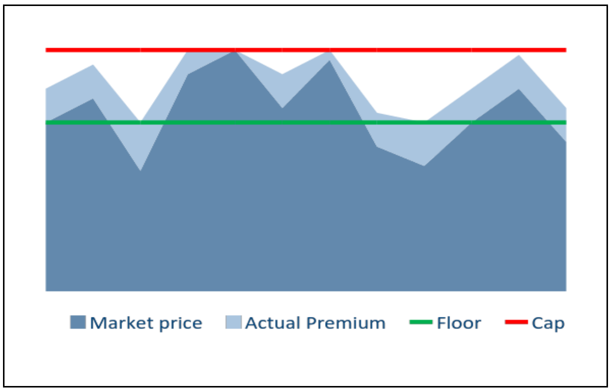


Figure 2: Functionality of cap and floor in a fix premium

One of the main challenges of this design is to set the cap and the floor, especially if it is set for a long time period (15-20 years). It can also cause difficulties when applying it with auction as there are more parameters to deal with.

Floating premium has the risk that the amount of support can be higher than expected (but not higher than the producer needs) if market prices tend to be low. This risk can be shared with the producer by applying **a floor for the market price**[27]. If the market price is lower than the floor, the **floor price** is used instead when calculating the premium. This means less risk for the supporter but more for the investor. Higher investor risk can cause higher cost of capital and therefore higher reference values.[28] A **cap** for the (reference) market price can be used also. This can be set equal to the reference value, i.e. the producer does not have to pay back if the market price is higher than the reference value (no negative premium).

One of the main challenges of this design is to set the value of the cap and the floor, especially if it is set for a long time period (15-20 years). It can also cause difficulties when applying it with auction as there are more parameters to deal with.

With ***a floating premium*** there is the risk that the amount of support turns out to be higher than expected if market prices tend to be low. This risk can be shared with the RES-producer by applying a floor for the market price. If the market price is lower than the floor, the **floor price** is used instead when calculating the premium. This means less risk for the supporter but more for the investor. A **cap** for the (reference) market price can be used also. This can

[27] It is equivalent to apply caps and floors to the premium but it is a more general approach to apply them to the market price as the reference value changes category by category.

[28] This is the approach followed by The Netherlands, where a yearly price setting is combined with a relevant floor price for the floating premium. This system puts a relatively high part of the risks on the RES investor.

be set equal to the reference value, i.e. the producer does not have to pay back if the market price is higher than the reference value (no negative premium).

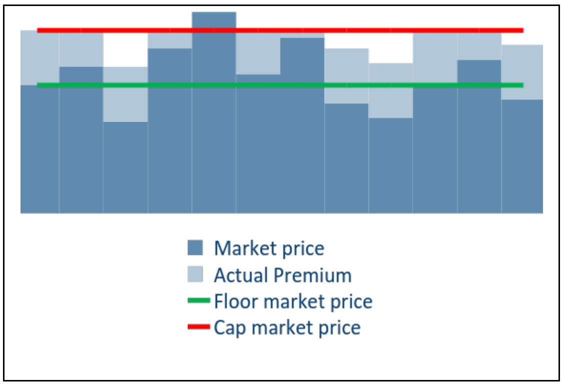


Figure 3: Functionality of cap and floor in a floating premium

2. Payment of the premium in case of negative prices

Negative market prices show an oversupply of electricity and should in an undistorted market environment give a signal to all plants to stop or reduce production.

If no specific scheme is put in place regarding negative prices, a premium can distort this signal if the sum of the market price and of the premium is higher than the marginal cost of the plant. This case can be quite common as the marginal price is close to zero for many RES producers. One response to this problem could be to set the premium at zero in case of negative prices. For higher marginal cost producers a reduction of the premium could be enough to reduce the revenue below the marginal cost. However, adapting the market premium as a response to negative prices leads to unexpected and sudden variations in the overall support level, directly impacting the intraday market behaviour of RES-producers. Additionally, this approach affects the long term income predictability relevant for investment decisions since forecasting the exact occurrence of these negative prices is far more complicated.

However, it is important to point out that the occurrence of negative electricity prices is as such not a consequence of increasing shares of RES but rather a result of the lack of flexibility in the power system.[29] Further, whenever electricity is sold at rather low or even negative prices, the market will promptly react and create a demand for this energy.

The German market premium scheme[30]

The scheme has first been introduced in Germany on an optional basis in 2012. Since August 2014, it is mandatory for all new RES producers with an installed capacity above 500 kW.

[29] Negative Electricity Prices: Causes and Effects - An analysis of recent developments and a proposal for a flexibility law, Agora Energiewende, August 2014.
[30] "Direktvermarktung mit gleitender Marktprämie", i.e." direct marketing with sliding market premium".

Basic functionality of the FIP scheme

In a nutshell, the market premium scheme obliges RES plant operators to sell, directly or through a third party, their electricity produced on a market place, as a prerequisite for claiming a support entitlement, i.e. the market premium, in addition to their market revenue (linked to the quantity sold and the market price achieved). The objective of the FIP scheme is twofold:

- Endow RES producers with an active role in the electricity market by bearing market risks linked to short term price fluctuations and balancing responsibilities.

- Increase the overall cost-efficiency of RES generation (through improved forecasts, improved maintenance schedules, improved marketing strategies, etc.) by linking RES revenues to market signals, thus potentially contributing to a slight reduction in overall RES support costs for new RES installations.

The overall functionality of the German FIP is described in full length in annex 8.

Key lessons learnt

The following (preliminary) assessment can be made of the scheme:

- **Large acceptance of the scheme by RES producers**: Between 2012 and 2014, the installed capacity of RES installations falling under the optional market premium scheme increased by 54%, making a share of 52% of total installed RES capacity and 63% of RES electricity produced in 2014. Mainly wind and biomass producers opted for the market premium scheme on a voluntarily basis. From this perspective, the FIP scheme including a generous ‘direct marketing’ bonus has been very effective in incentivising RES producers to become active participants in the market.

- **Alignment of risk level between RES and conventional producers**: RES producers bear the same balancing risks as any other market participant. Beyond balancing risks, they are also confronted with a range of other risks linked for example to financing, running their installation (maintenance needs) and the availability of their production factors. However, they are only confronted with a monthly price risk, while being shielded from medium to longer term price risks. With the FIP, market risks for RES producers are coming close to the one borne by conventional electricity producers.

- **Incentives for cost-optimising RES generation**: While FIT schemes promoted a “produce-and-forget”-behaviour, the FIP framework introduces small incentives to optimise RES generation in accordance to market signals leading to higher overall cost-efficiency. The optimisation is achieved through e.g. improved forecasts, adjustments in production and maintenance schedules in accordance to market signals and by upgrading technological features of the installation.

- **Emergence of new business models**: Since RES producers can also outsource the marketing activity to a third party, the introduction of the FIP scheme incentivised new business models, e.g. specialised in aggregating RES production from a variety of RES installations to sell it on the market or in providing qualitative forecasting services. The diversification of responsibilities derived from the integration of RES producers on the market has led to more efficient marketing strategies and significant improvements in the quality of forecasts.

- **Emergence of new trading products on the spot market**: EPEX spot has introduced new short term trading products based on 15-minutes-tranches, more accurately reflecting the specific RES-production patterns. Short-term trading products allow for a deeper participation of RES producers (or direct marketing companies) on the intra-day market, taking into account RES features linked to intermittency and resulting forecasting needs.

- **Effective transition towards unsupported RES:** The FIP scheme forces RES producers to gain relevant skills for a successful participation in a market setting. These experiences gained under the FIP scheme will be very valuable for all RES producers intending to remain in the market, once their support entitlement has expired.

The way forward

As of January 2016, new RES producers with an installed capacity above 100 kW will be falling under the FIP scheme. Another design option will be introduced with respect to negative prices.
An in-depth assessment of the overall support scheme (incl. the FIP mechanism) is foreseen for December 2018. With the introduction of tendering procedures for PV, wind onshore and offshore from 2017 onwards, the reference support value will be defined though a tendering mechanism.

4.2.2 Challenges

While FIPs have the advantage of enabling RES producers to participate in the market while being shielded from long term price risks, challenges linked to the additional costs due to the market integration need to be considered when designing the scheme. Another challenge is the achievement of a high degree of market integration with a newly introduced FIP scheme, without touching upon existing support arrangements.

1. Additional costs for market integration

Implementing FIP as support mechanism induces new costs and risks elements for RES producers when integrating into the market, such as:

- transaction costs (e.g. stock exchange registration fees, marketing staff costs);
- balancing costs (electricity is sold according to schedules and producers have to buy or sell balancing energy if they deviate from schedule); and
- forecasting and scheduling costs – they can be substantial especially for intermittent generation where producers need to forecast resource availability (e.g. meteorology software or forecast) and adjust the schedules accordingly. In many cases forecasts are accurate enough only quite close to real time (few hours ahead).

For new entrants these costs can be taken into account in the reference support value, set either through an administrative or competitive procedure:

- In a competitive procedure, the compensation of these costs can be integrated in the total level of remuneration asked by the bidders.
- In an administrative procedure, it has to be estimated by public authorities, which can be a challenge given the lack of experience on this issue. More generally, the level of the "direct marketing" premium will be a trade-off between the will to develop this activity and the costs of the scheme.

2. Disproportionate level of risks for small RES producers

In case of small producers the aforementioned costs might outweigh the advantages of market integration. Hence exempting small producers from the obligation to sell their electricity on the market is an appropriate design feature. This is also foreseen in the EEAG where a provision for the exclusion of small installations[31] from direct marketing and bearing normal balancing costs is included.

3. Eligibility of existing RES producers to a new premium scheme

Ideally, changes in the support systems should apply only for new entrants to ensure security of investment. However, it is worth considering integrating existing plants falling under a FIT scheme into a FIP scheme on a voluntary basis. A FIT system can be relatively easily converted into a floating premium system, setting the reference value equal to the FIT. This might cause only a minimal increase in risks for the producer (depending also on how the reference support value is set) and some extra cost as a result of direct marketing (see above). These factors can be compensated by setting the reference support value for the FIP a little higher than for the FIT. It is a challenge however to set this "direct marketing" bonus appropriately.

4.2.3 Concluding remarks on market integration of FIP schemes

In a FIP scheme, RES producers participate in the market while being shielded, in most cases, from long term price risks. CEER is convinced that the FIP scheme, with an appropriately defined reference period for setting the reference market price and without caps and or floors, is an appropriate approach to bring RES producers gradually as close as possible to real market conditions.

Finally, imposing balancing responsibilities on RES producers is a key parameter for achieving market integration.

Case study on the "Contract for Difference" scheme in the UK

The Contract for Difference (CfD) renewable support scheme is one of three major policy interventions introduced under the Electricity Market Reform (EMR) under the Energy Act 2013.
It aims to overcome the limitations of the RO (discussed in section 2) by achieving the following:

[31] According to Article 125, these are demonstrations projects or installations with capacity lower than 0.5 MW for all RES technologies, except for wind for which a limit of 3MW or 3 production units is foreseen.

- provide greater revenue certainty to investors of RES generation;
- reduce the borrowing costs of financing RES generation projects; and
- encourage competition both within and between generation technologies to deliver cost-efficient RES capacity and improve the affordability of low carbon energy to consumers.

Basic functionality of the CfD scheme

The CfD scheme places an obligation for RES generators to sell electricity. The CfD acts as a contractual agreement between the generator and a Government owned counterparty - the Low Carbon Contracts Company (LCCC). This agreement guarantees that the generator will be paid a set price, 'the strike price', for each unit of electricity produced for the duration of the agreement (15 years). RES generators bid the strike price they are willing to receive for a specified capacity (MW) in a competitive auction. Funding is awarded to RES generators based on these bids, with cheapest strike price bids always accepted first. Once the successful bidders sign their CfD agreement, they have one year to provide evidence of substantial commitment to investment in a project, or the contract will be cancelled and the funding recycled. Once projects are operational, CfD holders have two main sources of revenue from RES generation:

- **Direct revenue from electricity**: In the short term, the generator will gain revenues from electricity sold in the wholesale market; and
- **Compensation from CfD**: Typically, the strike price will be set at a higher price than the average market price for electricity. This 'premium' allows generators to recover the additional costs generally associated with RES technologies. When the strike price is higher than the 'reference price' – a measure of the average electricity price in the GB wholesale market - the generator is compensated the difference.

RES generators under the CfD scheme will be subject to the same standard balancing responsibilities as defined by UK national regulation, i.e. they are responsible for settlement costs associated with deviations from their delivery commitments.

Key lessons learnt

As of December 2015, none of the successful projects have started generating. Therefore, only the following indicative lessons learnt can be drawn:

- **Value for money:** Strike prices established by the first auction cleared at a level significantly lower (on average 17% lower) than the administrative strike price, for almost all RES technologies, in all years. The administrative strike price, set by Government was determined to be a 'fair' return on investment should the competitive auction not result in a cleared strike price. This provides early evidence that the auction process is delivering better value for consumers, whilst still supporting new RES projects.

- **Transparency**: For the first time in any GB renewable support mechanism, the CfD auction provided advance prices of RES technologies made available in the public domain. This process has revealed industry determinations of the actual costs of providing RES, for a large number of RES technologies. This level of transparency on the cost of RES generation has been missing from previous schemes, and should help to inform better auction design in the coming years of the CfD scheme.

- **Technology competition:** Onshore wind dominated the CfDs in the Pot for established technologies, with offshore wind dominating the Pot for less-established technologies. The auctioning process balances the need for cost effective support schemes for RES generation, whilst recognising that less-established technologies will need further support. The domination of wind projects in both pots may mean that other technologies may find it hard to compete for funding through the CfD scheme, leading to a convergence of new capacity to a small number of generation technologies (ie the most efficient technologies in each Pot.

4.3 Concluding remarks on market integration

Market integration can be achieved under both FIP and Quota scheme, while a FIT scheme would bear only a very limited potential for market integration. Producers are fully incentivised to conduct short term optimisation by rescheduling production in order to optimise their revenue. Flexible technologies (e.g. biomass, hydro with water retention) can make a good use of that. However, incentives for adjusting production to market signals remain distorted to some degree as RES producers are entitled to an additional revenue (linked to generation), expressed as a premium or a certificate price

Sharing of risks between producers and consumers (contributors) is highly dependent on the concrete design of market integration. Fix premiums and quota systems have the best market integration potential but those are the riskiest designs as well (both for investors and contributors). Floating premium mitigates investors' risks. The level of this risk mitigation can be adjusted by tuning the length of the period over which the reference market price is fixed: the longer the period (e.g. a year) the smaller the risk mitigation and the higher the market integration effect. Setting the reference market price ex-ante or ex-post might also influence the market integration effect, the latter one encouraging flexible producers to sell on short term markets.

Finally, CEER is confident, that in an existing electricity market setting, short term markets will gradually develop once RES producers bear balancing responsibilities and risks.

5 Conclusions and way forward

The RES targets for 2020, flanked by national support schemes, have created the momentum for scaling up RES generation throughout Europe. The increasing shares of RES and the evolution in terms of generation costs and competitiveness along changes in the regulatory framework now call upon MS to adapt their support schemes towards more cost-efficiency and market integration. The 27% RES target for 2030 and the ongoing discussion about the future electricity market design further accentuate the importance of enhanced support mechanisms striving for more market integration of RES.

The practical implementation of greater cost-efficiency and market integration advocated by EEAG is still pending in many MS, subject to national circumstances affecting design choices yet to be made.

Full market integration can only be achieved once RES generators operate on a level playing field with conventional producers, i.e. they have access to the same markets, bear the same market responsibilities and are, in principle, no longer reliant on subsidy. As such, the market arrangements should be non-discriminatory, reflect marginal costs where appropriate, and should not incentivise market-distorting behaviour. Hence, striving for a full market integration of RES is a long term objective for which the ground should already be actively laid today.

Against this background, CEER believes that FIP schemes provide a suited framework used in the EU that brings RES electricity into the market while integrating RES producers to a feasible extent, where they are confronted to short term market signals but shielded from long term price risks. However, FIT schemes should remain a support option for small scale installations.

Additionally, quota systems are, under certain conditions, an effective market oriented support scheme, where only targets are set administratively while leaving the certificate market to settle the premium awarded on top of energy market price.

Further, CEER is convinced that where a competitive setting exists, competitive allocation mechanisms as a means to determine the level of support bear the potential to bring down RES support costs. CEER favours an analytical approach, where MS analyse for each RES technology to be supported, whether the conditions for competitive procedures are given. Whenever the assessment turns out to be negative, MS should have the right to fall back on administrative procedure for determining the level of support.

In view of achieving EU's 2030 RES target in the most efficient way, CEER considers that a greater coordination between MS should be encouraged and new approaches to cross-border cooperation should be investigated in depth. Cross border schemes limited to neighbouring countries appear somehow easier to conceive in comparison to a common EU wide support scheme. Nevertheless, the barriers to any design, implementation and surveillance of joint cooperation mechanisms are numerous, especially because support schemes are touching upon a wide range of national regulations, covering e.g. technical, environmental, investment, insurance, property, and taxation laws.

A greater convergence between national support schemes makes logical sense as markets are becoming increasingly coupled and is nonetheless already on the way through the common rules for the design of support defined in the latest State Aid Guidelines, e.g. regarding the determination of support levels through tendering procedures as well as for market integration under FIP schemes.

Most NRAs in the MS have specific responsibilities in the implementation of RES support schemes. In combination with their traditional regulatory tasks, NRAs should seek to lay the ground for an appropriate market environment enabling the integration of RES electricity and producers into a competitive electricity market. This includes (1) ensuring that RES producers have access to the network and (2) access to all relevant energy markets on a non-discriminatory basis, (3) appropriate balancing rules and (4) short term balancing products reflecting RES features (e.g. intermittency and reliability on good forecast). In this context, CEER draws the attention to the fact that prevailing market barriers (e.g. price regulation, privileges for self-consumption, etc.) to the development of a competitive energy market further hinder the integration of RES.

CEER will continue to monitor the developments in support schemes across the EU and to push for a timely adoption of the network code on Electricity Balancing aiming at a better market integration of RES generation. Last but not least, CEER will continue to enable the exchange of good regulatory practices.

CEER is convinced that NRAs' expertise in the field of RES, which carries very high stakes for consumers, should be constantly sought by all relevant decision-making institutions.

Annex 1 – List of abbreviations

Term	Definition
ACER	The Agency for the Cooperation of Energy Regulators
CEER	Council of European Energy Regulators
Commission	European Commission
EC	European Commission
EEAG	Guidelines on State Aid for environmental protection and energy
EEX	European Energy Exchange
EMR	Energy Market Reform
ETS	European Trading Scheme
FIP	Feed-in Premium
FIT	Feed-in Tariff
FP	Financial prequalification
kWh	Kilowatt hour
kWp	Kilowatt peak
LCCC	Low Carbon Contracts Company
MC	Marginal costs
MP	Material prequalification
MS	Member States
MWh	Megawatt hour
NRA	National Regulatory Authority
PV	Photovoltaic
RES	Renewable Energy Sources
RO	Renewable Obligation
ROC	Renewable Obligation Certificate
TWh	Terawatt hour
WACC	Weighted average capital costs

Annex 2 – Key EEAG requirements for operational support granted to RES

Market integration of RES

From 1 January 2016 onwards all new RES support mechanisms will have to include design elements enabling RES generators (beneficiaries of the aid) to sell their electricity produced in the market while having "balancing responsibility" for their actions. The EEAG sets out the following conditions:[32]

- Operational aid is to be granted as a premium in addition to the market price where the generator **sells its electricity directly in the market**;
- Beneficiaries are **subject to standard balancing responsibilities**, unless no liquid intra-day markets exist; and
- Measures are put in place to ensure that **generators have no incentive to generate electricity under negative prices**.

As an alternative to the introduction of market premiums (for smaller installations FITs), MS may grant support by using market mechanisms such as green certificates (quota systems). In such cases MS must provide evidences of compatibility with the internal market, namely that green certificates as form of support:

- Is essential to ensure the viability of the RES concerned;
- Does not result in any kind of overcompensation, whether over time and across technologies, or for individual less deployed technologies; and
- Does not impede RES producers to become more competitive.

The use of competitive processes

From 2017 onwards, Member States will be required to determine the level of operational support granted to RES installations via competitive bidding processes[33]. In principle, the competitive bidding procedures should be open to all RES generators (i.e. conceived as technology neutral). However, if this approach leads to suboptimal results, for example due to network constraints or diversification needs, bidding processes can be designed to be technology-specific.

The use of administrative processes

The level of support can still be determined through an administrative procedure, whenever the:

- Implementation of the bidding procedure is jeopardised by the limited number of projects (no competition), a higher support level outcome or low project realisation rates; or

[32] Note these requirements do not apply to smaller RES installations with an installed capacity below 3 MW (or 3 generation units) for wind or below 500 KW for other sources.
[33] In a transitional phase covering 2015 and 2016, only 5% of the planned new electricity capacity from renewable energy sources needs to be tendered through a bidding process.

- Installed capacity of the RES installation below 6 MW of wind power (or 6 generation units) or below 1 MW of power from other renewable sources.[34]

In addition, the EEAG sets clear conditions for determining support in the absence of a competitive bidding process, notably:

- The aid per unit of energy does not exceed the difference between the total levelised costs of producing energy (LCOE) from the particular technology in question and the market price of the form of energy concerned;
- The LCOE may include a normal return on capital. Investment aid is deducted from the total investment amount in calculating the LCOE;
- The production costs are updated regularly, at least every year; and
- Aid is granted until the plant has been fully depreciated according to normal accounting rules in order to avoid that operating aid based on LCOE exceeds the depreciation of the investment.

Applicability

The Guidelines are applicable from 1 July 2014. However, to maintain legal and investment certainty, they will not apply to existing RES support schemes that have already been notified to the European Commission, unless Member States change their support scheme. In this case MS will need to notify the changes to the scheme to the Commission, who will assess it under the new Guidelines.

Decisions to date

To date the European Commission has made a small number of decisions under the new State aid framework and raised no objections to the notified adaptation of national RES support schemes in the following MS:

Member State	Case number	Case title
Denmark	SA.37122	Aid to household wind turbines and offshore wind turbines with an experimental aspect
Denmark	SA.36204	Aid to photovoltaic installations and other renewable energy installations
Estonia	SA.36023	Support scheme for electricity produced from renewable sources and efficient cogeneration
Germany	SA.38632	EEG 2014 (Renewable Energy Sources Act 2014)
		Support to 20 large offshore wind farms under the EEG Act 2014
Netherlands	SA.39399	Modification of Dutch SDE+ RES scheme
Portugal	SA.39347	Support scheme for experimental and pre-commercial renewable technologies
United Kingdom	SA.36196	Contract for Difference for renewables in UK

Table 1 – Overview of MS[35]

[34] Ibidem.

[35] Only decisions related to notified aid related to the operational support of RES are being listed. Source: State aid register of DG competition.

In an internal review conducted among CEER members, 12 MS have indicated that they have or are in the process of adapting their RES support schemes to be in line with the new support framework set out by the EEAG (for more details see annex 3).

In the course of this paper, selected case studies will provide detailed information about how selected MS have introduced support elements steering towards deeper market integration of RES and competitive bidding procedures in their respective national support schemes.

Annex 3 – Overview of NRAs role in the field of RES support

MS	Adapting schemes in near future?	NRAs' role in…					
		Design	Advice	Implementation	Administration	Exemption	Other
AT	**No**	**Partly** - Low income households can be exempted from paying the full amount of renewable levies. ECA issued a decree how this process has to look like.	**Yes, non-binding advice.** E-Control assisted regarding the design of the funding scheme.	**Yes** • The federal ministry of science, research and economy can ask the NRA E-Control for advice on setting the FITs. • NRA sets the price for the guarantees of origin for supported RES. • NRA is asked by the ministry to make a forecast on supported RES produced and cost for the following year and on total energy consumed in AT. Those forecasts are used to set the Okostrompauschale (lump sum charge) and the Okostromforderbeitrag (surcharge on grid usage and loss charge).	**Yes** E-Control has a database where supported renewables have to register to get guarantees of origin issued. E-Control also issues a yearly monitoring report on the state of the supported renewables in Austria. Contracted capacity, produces energy, costs and gives advice on potential for improvement.	**Yes** Low income households can be exempted from paying the full amount of renewable levies. ECA issued a decree how this process has to look like.	**Yes** ECA is responsible for the electricity labelling. To make suggestions regarding improvements of the support system research on this topic also takes place.
BE	**Yes**- it was an element of the coalition agreement of the current government. Except for the Brussels region, this is under analysis by the administration of Energy. The energy policy responsibilities are divided between the regions and the federal state. The three regions, Flanders, Walloon and Brussels,	**Partly -** A proposal is made by the NRA (except for the Flemish part of the country) and then adopted into legislation.	**Yes, a non-binding advice** is provided by studies. For example: long term projection of total support costs for the market, functioning of quota system. CREG, the federal regulator and NRA, support the federal government in his policy for RES. The regional	**Yes**, for example, for the Walloon region, the regulator calculates the LCOE for different technologies and issues support certificates. In Brussels, the regulator monitors the required support levels and GC quota-levels.	**Yes,** the regulator is responsible for certificate creation, certificate registration, follow up certificate trade and certificate cancellation.	**No**, the regulator is responsible for the application of the legislation.	**Yes**, NRA provides information to the stakeholders &the ministry regarding certificate trade (trade statistics), status minimum price sells, certificate issuing overshoot, publication of market relevant statistics, annual report relating to market

MS	Adapting schemes in near future?	NRAs' role in…					
		Design	**Advice**	**Implementation**	**Administration**	**Exemption**	**Other**
	are responsible for renewable energy, except for offshore wind energy.		regulators do this for the regional governments and their policies				functioning.
CZ	**No**	**Partly** The Energy Regulatory Office ['ERO'][36] issues its Price Decision laying down feed-in tariffs and green premiums for promoted energy sources.	**No**	**No** CZE's current aid scheme for renewable energy is set out in the law on renewable energy from 2012 - Act No 165/2012 on Promoted Energy Sources and Amending Certain Laws, as amended.	**No** • Electricity producers are required to register as operating aid for electricity with the market operator, which ensures the payment of aid in the form of green premium. • Electricity sold in the form of the purchase prices paid by "mandatory buyer", who pays the fixed purchase price and the market operator pays the difference between this market and the hourly price of electricity.	**No**	**No**
DE	**Yes** • Current RES support scheme is set out in the Renewables Energy Act of 2014 (EEG). It has been notified to the Commission and has in principle been authorised for 10 years. • Certain elements of the aid scheme will need to be re-notified before the end of 2016 and before the end of	**Partly** • The Ministry for Economics and Energy is responsible for designing the key elements of the RES support scheme. • The NRA designs the rules for the marketing of the	**Yes, non-binding advice** • The NRA is providing its expertise to the Ministry when it comes to the design of the RES support scheme, e.g. by contributing to the drafting of RES related legislation, participating in	**Yes** • The tendering procedure for setting the level of support for freestanding PV installations is being fully implemented through the NRA, i.e. it manages all administrative procedures linked to the call for tenders including the awarding decisions for a selection of bidders.	**Yes** • NRA oversees the equalisation mechanism between the TSOs for the RES quantities sold on the market and is controlling the calculation basis of the TSOs for determining the annual RES surcharge. • Controls that the TSOs correctly charge energy suppliers with the RES	**No**	**Yes** • Active in different RES related work streams led by the Ministry in charge as well as in statistical working groups responsible for the compilation of RES statistics. • NRA publishes an annual statistical

[36] Under Section 2c of Act No 265/1991 on the Competences of the Czech Republic's Authorities in the Area of Prices, as amended, and under Section 17(6)(d) of Act No 458/2000 on the Conditions for Business and State Administration in Energy Industries and on Amendments to Certain Laws (hereinafter "the Energy Act"), as amended, and under some section of Act No 165/2012 on Promoted Energy Sources and Amending Certain Laws, as amended.

MS	Adapting schemes in near future?	NRAs' role in…					
		Design	Advice	Implementation	Administration	Exemption	Other
	2017. • The Federal Ministry for Economics and Energy is in charge of proposing the appropriate legal changes to the EEG.	RES quantities by the TSOs (via subordinance) & for the balancing scheme, which are very important for the functioning of the overall RES support scheme.	discussion fora where new elements for the schemes are being discussed (e.g. how to introduce tendering procedures) • The design of the pilot tendering scheme for freestanding PV installations as well as the design of the ordinance for the establishment of a registry for RES installations has been developed by the Ministry under close participation of experts from the NRA.	• NRA calculates the reference support value for PV installations according to a predefined reduction scheme & publishes it every month • TSOs are setting the level of the annual RES surcharge under the scrutiny of the NRA, which is controlling the calculation.	surcharge, especially when it comes to allocate the different surcharge levels (e.g. reduced surcharge for energy-intensive industries, auto-consumption) to the electricity consumed. • Oversees that network operators transmit and publish all financial information related to the payments of RES support made to RES installations. • Supervises network operators in their congestion management activities, to ensure that the capacities of RES installations are only reduced as a last option. • Registers all RES installations in Germany. Only with the proof of registration are they entitled to claim support from the DSO. In the medium term it is foreseen to widen the scope of the registry to cover all electricity producing installations (i.e. also conventional) as well as all relevant market players. • The Renewables Energy Act attributes to the NRA clearly defined powers to control activities of network		report on the state of play of RES: e.g. information on installed RES capacities, regional deployment pattern, payments made to RES installations, etc. • Every 4 years, the NRA (together with other public institutions involved in the implementation of the RES support scheme), contributes to the compilation of the progress report by the Federal Government, which looks at the experiences made with the implementation of the EEG.

MS	Adapting schemes in near future?	NRAs' role in…					
		Design	**Advice**	**Implementation**	**Administration**	**Exemption**	**Other**
					operators, electricity suppliers and RES installations in case of initial suspicion regarding any unlawful application of the RES scheme (e.g. unjustified support payments).		
ES	**Yes** Recent draft introducing bidding procedures in 2015-2019 for biomass and wind technologies. Ministry is responsible for setting tender conditions	**No**	• **Yes, non- binding advice.** Non-binding report of the new scheme draft and responsible for stakeholders consultation.	**Yes** Since 2009, CNMC is responsible for payment process. According the new draft, CNMC will be the supervisor of the bidding procedure.	**Yes** CNMC manages database for generation plants and operational data. Also responsible for inspections and audits.	**No** CNMC does not design auto-consumption system but provides non-binding reports.	**Yes** CNMC is responsible for managing the Guarantee of Origin System and disclosure of electricity.
FI	**No** • FIT for wind power is notified according to the old guidelines. • There is a quota of 2500 MVA for wind power generators. No changes are expected until the quota is full. • Design process for a completely new support scheme expected for 2017. • The Ministry is planning to notify the FIT for timber chip burning power plants according to the new EEAG.	**No**	**Yes**, **non-binding advice**. • FEA comments on draft legislations, especially if there are any changes to the current system; • Participation in working groups related to support schemes.	**Yes** • FEA implements the legislation and manages the feed-in tariff system. • It accepts the power plants into the system, pays the feed-in tariff, advice in the application process and provides information about the system, and assesses the implications of feed-in tariff. We will most probably implement all future RES support	**Yes** – see previous	**No**	**No** Other than tasks involved in managing the system.

MS	Adapting schemes in near future?	NRAs' role in…					
		Design	**Advice**	**Implementation**	**Administration**	**Exemption**	**Other**
	• Any major adjustments are not expected. The support is technically more a feed-in premium than a tariff.			schemes as well.			
FR	**Yes** • RES support schemes have been adapted to be in line with new EEAG. The energy transition law voted by the Parliament in July 2015, creates a new support scheme (complement de remuneration), which will consist of a market premium. It will cohabit with the current FIT (small-scale installations should still benefit from FITs). • Ministerial decrees describing the design & support levels for each technology should be published by end of 2015. • FR has already used tendering procedures as a support scheme for RES, & should not undertake any adaptation in that regard. • It is very likely that FR will have to adapt the exemptions schemes of RES financing that benefit to specific electricity consumers in line with EEAG guidelines, even	**Partly** • The French regulator (CRE) does not design the FIT/FIP schemes, which is the responsibility of the government. • CRE actively participates in the ministerial consultations and workshops to prepare the legal framework. • For the tendering processes, CRE drafts the specification documents, which are finally approved by the ministry.	**Yes, non-binding** • CRE issues an opinion on the FIT/FIP schemes, which mainly analyses the profitability that the support schemes should induce for RES producers. • CRE also issues an opinion on the choice of the winner decided by the government at the end of the tendering processes.	**Yes** • CRE is actively involved in the tendering procedures: it analyses the bids based on the criteria defined in the specifications, and proposes the winner(s) based on the ranking established. • CRE also calculates each year the cost of support to renewables, and the level of the levy (in €/MWh) that is necessary to finance them. (This levy, namely CSPE, also finances other public service charges such as tariff equalisation in overseas territories and social measures.) If the ministry does not formally approve the level proposed by CRE, it comes into force the year after, with a limit in the annual increase of +3 €/MWh.	**Yes** The funding scheme is defined in the law, and the French regulator has no responsibility in its design. CRE does however monitor the financial flows: it validates the amounts transferred by electricity suppliers and network operators (which collect the tax) to the bank account administrated by Caisse des Depots, and instructs Caisse des Depots on the transfers it should operate.	**Yes** CRE does not design the exemptions of funding: they are provided for in the law. CRE receives the demand of eligible consumers, validates them if they comply with the legal framework and instructs Caisse des Depots on the payments that should be completed.	**No**

MS	Adapting schemes in near future?	NRAs' role in…					
		Design	**Advice**	**Implementation**	**Administration**	**Exemption**	**Other**
	though no concrete action has to be taken so far.						
GB	**Yes** The Ministry (Department of Energy and Climate Change) is responsible for adapting RES Support scheme design.	**No**	**Yes, non-binding advice**. Ofgem advises the UK government on the practical implementation implications of their proposed RES support schemes, usually in the form of consultation responses.	**No**	**Yes** Recipients of RES support payments must register with Ofgem, which then reviews the data submissions to monitor compliance and allocate payments.	**No**	**Yes** • Ofgem operates helplines for and provides detailed guidance on a number of RES schemes. • Ofgem also issue regular reports on the funds allocated.
GR	**Yes** No formal decision yet but most certainly needed and preliminary discussions have been initiated. a) The responsible body is the Ministry. b) There is no definite decision on the kind of adjustments introduced, neither on the timeframe.	**No** There is no constitutional responsibility of RAE to design all or part of the support scheme but contribution is normally asked for, e.g. participation in preparatory meetings and task forces for drafting relevant legislation etc.	**No** There is no constitutional responsibility of RAE to issue advice on the design of the support schemes but as previously mentioned contribution is normally asked for.	**Yes** • RAE has decisive responsibilities on the calculation and allocation of the RES levy to different types of customers, based on a methodology defined by the Ministry upon RAE's advice. • RAE is also providing advice to the Ministry on various implementation details of the RES support scheme such as FiT levels per RES technology categories and annual FiT eligible capacity levels (caps) per RES technology categories • Development of tendering procedure rules. Note that these responsibilities are	**Yes** RAE is responsible for the issuance of the production license of RES plants over 1MW and RES hybrid plants, keeping the relevant registry, monitoring their progress and enforcing administrative sanctions when necessary.	**Yes** RAE provides advice to the Ministry on the methodology for the burden sharing of the RES cost and its allocation to different customers.	**Yes** RAE publishes its opinion on various issues related to legal aspects or ministerial decisions that affect the sectors of its responsibility whenever necessary, e.g. opinion on the FiT level.

MS	Adapting schemes in near future?	NRAs' role in…					
		Design	Advice	Implementation	Administration	Exemption	Other
				not part of the design phase but rather result from it.			
HR	**Yes** • The Ministry of Economy (in charge of the energy sector) is designing a new national RES support scheme in line with mentioned Guidelines. It plans to have a new RES support scheme in force on January 1st 2016. • Additionally, other ministries are providing certain target groups with support for RES production for self-consumption (e.g. Ministry of Entrepreneurship and Crafts for SMEs, Ministry of Agriculture for farms). Those support measures are designed in line with the current Guidelines on State Aid for Environmental protection and energy.	**No**	**Yes**, **non-binding advice** • The Ministry of Economy asks HERA for its opinion on draft legislation relevant to RES support schemes. • The Ministry also regularly includes experts from the NRA in working groups drafting legislation, policy papers and other documents pertinent to the RES support schemes. • As a rule, all public bodies are required to submit to the NRA draft legislation relevant to the energy sector for a non-binding opinion.	**No**	**Yes** • Current & anticipated RES support schemes require producers receiving support to obtain an eligibility status provided by HERA. The status of an eligible electricity producer provides dispatch priority. For production facilities that do not receive RES support via the current FIT, the eligibility status is used as a registration procedure necessary for issuing Guarantees of Origin (RES and CHP). The eligibility status is obtained based on criteria (legislation) defined by the Ministry of Economy. In brief the criteria comprises of metering requirements (net production) and requirements related to supervision. HERA has been given the task of supervising power plants and producers in upholding the conditions of the eligibility status. • HERA oversees the implementation and	**No** The current and anticipated RES support scheme does not provide exemptions.	**No** HERA has no other duties related to the RES support scheme other than those previously described.

MS	Adapting schemes in near future?	NRAs' role in…					
		Design	**Advice**	**Implementation**	**Administration**	**Exemption**	**Other**
					administration of the RES scheme carried out by the Croatian Energy Market Operator (HROTE). In addition, HERA monitors HROTE in relation to other energy legislation (primarily, the Electricity Market Act and the Gas Market Act).		
HU	**Yes** • Main responsible body: Ministry of National Development Involved in the concrete design: Hungarian Energy and Public Utility Regulatory Authority (HEA; regulator) and MAVIR Ltd. (TSO) • The introduction of the new support scheme (including tenders) is planned by 01.01.2016.	**Yes** • The Ministry of National Development asked HEA to design the tendering process and the FIP scheme. • HEA expects to be involved in the design of other elements and in preparing the legal framework also. Some design elements are planned together with the TSO and other industry players (including consumers). • HEA was also included many ways in the design of the current support system.	**Yes, non-binding advice** – see previous.	**Yes** Currently HEA is responsible for setting the support period and the supported amount in the FiT system on a project-by-project basis and also monitors how the system works. It is not clear yet what roles HEA will have in the new system, however they are likely to play a role in the tendering procedures, adjusting the premium level (in case of old biomass plants) and monitoring the system.	**Yes** In the current system HEA sets the support period and quantity for each plant. We also collect data from these plants. The support is paid by the TSO and the burden is allocated on balancing responsible parties (mostly traders, which pass it on to consumers). HEA monitors this process.	**Yes** Consumers eligible for universal service are exempted from paying RES support. If they are eligible but buying electricity from free market then certain conditions apply for exemptions. HEA has the right to monitor if these conditions are met.	**Yes** HEA publishes a yearly report on the FIT system and RES-E production.

MS	Adapting schemes in near future?	NRAs' role in…					
		Design	Advice	Implementation	Administration	Exemption	Other
IE	**Yes** a) The Ministry for energy (part of the Department of Communications, Energy and Natural Resources) is the main body responsible for adapting the scheme's general design in accordance with the requirements set out in the new Guidelines. b) This question should be referred to the Department of Communications, Energy and Natural Resources.	**Partly.** The CER does not have design responsibility but may provide advice to the Ministry. To be clear, decision in this area rests with the Ministry and not the CER.	**Yes, non-binding advice.** The CER provides advice to the Ministry on matters such as the amendments to the support mechanisms to match the evolving all-island electricity market and/or in order to comply with the EU Target Model.	**Yes.** The CER advises the Ministry on implementation aspects of proposed RES support schemes; however, to be clear, decision here rests with the Ministry and not the CER.	**Yes.** The funds for the support of RES schemes are calculated and overseen by the CER, in line with the policy set by the Ministry.	**No**	**No**
IT	**Yes** - The main body responsible is Ministry for Economic Development (MiSE). Probably the relevant adjustments will be introduced by the end of 2015 (or even before).	**No**	**Yes, non-binding advice.** The NRA usually expresses its own non-binding opinion on a draft decree defined by Ministry (MiSE).	**No**	**No**	• No	Yes • Definition of how feed in tariff electricity is sold into the market. • Defining & updating tariff components designed to collect the revenue needed to cover the costs of incentives (but exemptions are defined by Government). • Monitoring the impact of incentives on utility bills and on the electricity system. • Presenting non-binding reports and opinions on the structure of incentives to the Government and the Parliament or

MS	Adapting schemes in near future?	NRAs' role in…					
		Design	Advice	Implementation	Administration	Exemption	Other
							to the competent Ministries.
LT	**No**	**Partly** • NCC does not design the FIT schemes. It is the government responsibility. • However, NCC prepared the legal framework for tariffs setting and auction processes according to the principles sets by the government.	**Yes, non-binding advice.** • NCC expresses its opinion on the draft versions of legislation. • Analyses the profitability for RES producers and impact on energy consumers.	**Yes** NCC sets a maximum FITs for electricity from RES plant with installed capacity over 10 kW and FITs for RES producers with installed capacity up to 10 kW every quarter. Also organised the auctions procedures for RES producers with installed capacity over 10 kW. The winner of the auction is that participant who has proposed the lowest tariff and who offered to build plant with bigger installed capacity.	**Yes** NCC controls the administration of public service obligations funds.	**No**	**Yes** Publication of quarterly statistical report on RES production.
LU	**Yes** - Ministry of Economy Timeframe unclear	**No**	**Yes, non-binding advice**. Informal advice on demand on all aspects.	**Yes** Setting the levy level, settling the compensation mechanism (settlement between cost and revenues for national support) deciding on the benefit of lower levy level for specific energy-intensive companies, approving standard contract between DSO and RES generators.	**Yes** Management and settlement of compensation mechanism (settle costs paid by DSOs to generator and revenues paid by consumers to DSOs).	**Yes** Granting lower levy level for companies which respect criteria defined by decree	**Yes** On demand

MS	Adapting schemes in near future?	NRAs' role in…					
		Design	**Advice**	**Implementation**	**Administration**	**Exemption**	**Other**
MT	**Yes** a) Responsible body is the Ministry for energy b) Ministry plans to introduction of competitive bidding for PV installations >1MW in 2016. The legal instrument for the introduction of competitive bidding is under preparation.	**Partly** The NRA does not design the support schemes but participates in the preparation of support schemes and the legal framework.	**Yes, non-binding advice.** The advice is in line with the function of the NRA to advise the Minister on matters of policy formulation in relation the regulated activities and its functions.	**Yes** The NRA has one of its functions to encourage the use of alternative sources of energy and f or such purpose in accordance with such regulations as may be prescribed, to impose levies on energy produced by non-renewable sources and grant subsidies in connection with the production of energy from renewable sources.	**Yes** The NRA administers the grant schemes for households and the allocation of feed-in tariffs established by law. The NRA keeps a register of all the RES and mainly consisting of PV's. Only PV's registered for a feed-in tariff with the NRA are entitled to receive this support. The NRA monitors also the time taken by the DSO to connect PV's to the grid.	**No**	**Yes** The NRA publishes information on its website on the state of play of PV capacities installed. As part of its role as the administrator of grant schemes the NRA has introduced a system of product registration which stimulates market transformation for improvement in quality of the RES technology placed in the market.
NL	**No**	**No**	**Yes, non-binding advice.**	**No**	**No**	**No**	**No**
NO	**No**	**No**	**Yes, non-binding advice.** The NRA provides advice on drafting of new regulation in this area.	**Yes** NRA ensures that suppliers comply to regulation on billing RES surcharge to end-users.	**Yes** The NRA monitors the price of the renewable surcharge to end-users.	**Yes** The NRA grants exemptions based on regulation.	**Yes** The NRA publishes an annual report highlighting the current status of the support scheme.
PT	**No** As far as ERSE knows about (once the Government is the responsible for RES Support scheme design).	**No**	**Yes, non-binding advice.** ERSE usually contributes to RES related legislation, based on drafts provided by the Ministry.	**No**	**Yes** ERSE monitors the financial flows between the electrical system and the producers, namely for the tariff setting process.	**No**	**No**
SE	**No** The current RES support schemes are already in line with the new guidelines.	**No**	**Yes, non-binding advice**. Swedish Energy Agency provides the Ministry with non-binding	**No**	**Yes** Swedish Energy Agency: Registration of installations and compliance (Electricity certificate system). Monitoring	**No**	**Yes** Swedish Energy Agency: all information to market participants.

MS	Adapting schemes in near future?	NRAs' role in…					
		Design	**Advice**	**Implementation**	**Administration**	**Exemption**	**Other**
			advices.		financial flows (PV support).		
SI	**Yes** • The main body responsible for adapting the scheme's general design is Ministry of Infrastructure of Slovenia. • In the adapted scheme (that is still in the stage of coordination) each year before 1 October (starting in 2015) a public tender shall be published, which must be open at least until 1 November (or until the anticipated increasing volume of funds for the implementation of support scheme for electricity for the next year is filled), which invited potential investors to submit proposals.	**No** The body responsible for adapting the scheme's general design is Ministry of Infrastructure of Slovenia.	**Yes, non-binding advice.** • In design issues related to the national RES support scheme Energy agency (NRA) has the ability to influence through comments, proposals, discussions and public hearings. • After the conclusion of each public tender for entry into the support scheme Energy agency carries out and publishes a review of selected projects in terms of tolerances fixed part of reference costs of electricity production in the projects chosen from the reference costs from the methodology and forwards it to the ministry of Infrastructure to identify deviations form the basis for further modification of the reference costs.	**Yes** Energy agency shall perform the project of selection process generating plants to enter into a support scheme and it consists of: 1) the publication of the tender; 2) evaluation and selection of projects to enter the scheme and 3) the adoption of decisions on the approval or rejection of the project.	**Yes** Energy agency ex officio constantly: verifies that the recipients of support fulfil all the conditions for obtaining support; registers and controls register of RES installations; monitors financial flows of the participants of support scheme; controls the recipients of a support (inspections by authorised person).	**No** Designing, granting or arbitrating exceptions is the responsibility of Ministry of Infrastructure of Slovenia.	**Yes** Energy agency is constantly: providing advice to market participants (personally, by phone, via professional events or through a single point of contact on an official web site); issuing expert reviews and publications (f.e. forecast of reference market prices of energy and energy sources, forecasts of the situation of production facilities, report on the achievement of national targets for renewable energy sources and cogeneration etc.)

Source: Information gathered through a questionnaire answered by NRAs.

Annex 4 – CASE STUDY on competitive procedures: Call for tenders in France

Following the liberalisation of gas and electricity markets in France, the notion of public service in the electricity sector has been introduced in the French corpus of legislation in 2000[37]. Among other provisions, this law introduced the legislative framework for feed-in tariffs as well as calls for tenders for RES installations. Well before the adoption of the EEAG, France had already put in place a legislative framework for awarding support to RES installations based on a competitive procedure.

Calls for tenders resulted, for projects awarded support, in the signature of a power purchase agreement, equivalent of a feed-in tariff. The *Energy transition* law, which has been adopted by the French Parliament in July 2015, introduced the notion of feed-in premium (‘*complément de remunération*’) which for installations of more than 1 MW will be awarded through calls for tenders.

The 2000 law on public service in the electricity sector provides that the government may resort to the tendering procedure when installed capacities do not meet the objectives it has defined. These objectives are specified in a regulatory text, namely multiannual programming document on investment in the electricity sector (‘*Programmation plurinannuelle des investissements*’), which sets quantitative targets in terms of installed capacity detailed by technology.

1. Key features of the tendering scheme

For technologies whose development exceeds governmental objectives under FITs, for instance because of a quick decrease in production costs which cannot be accounted for when defining FIT level, tendering procedures enable to control this development, by setting a predefined target of capacity eligible to support.

By encouraging competition amongst bidders in the purchase price they propose, tendering procedures also aim at minimising the cost of support of RES, which is financed in France by electricity consumers.

1.1 Basic functionality

Calls for tenders in France can be described as pay-as-bid, project related auctions, which means that candidates bid on specific projects and, if successful, sign a power purchase agreement at the price they proposed in their bid. The regulatory text which specifies the tendering procedure[38] defines two types of auctions, the so-called ‘ordinary procedure’ and ‘accelerated procedure’:

- In the ordinary procedure, candidates submit an extensive bid package. Projects are analysed on a multi-criteria basis, both quantitative and qualitative ones, which typically include price, environmental impacts, electricity network impacts, industrial development and contribution to R&D.

[37] Loi n° 2000-108 du 10 février 2000 relative à la modernisation et au développement du service public de l'électricité.

[38] Décret n°2002-1434 du 4 décembre 2002 relatif à la procédure d'appel d'offres pour les installations de production d'électricité.

- In the accelerated procedure, applications are submitted in a simplified form through a dedicated website. Bids are analysed on quantitative criteria only, such as price and CO_2 impact.

In both cases, tendering documents usually define eligibility criteria, such as the proof of property rights on the area of the project or technical & financial ability to conduct the project. A maximum price for bids can also be defined. Successful bidders must respect a deadline for the realisation of the projects[39], and penalties may be applied by the government if a bidder does not meet its obligations[40].

If the results of the tender prove to be not competitive enough, the government may declare it unfruitful and reject all bids.

1.2 Contribution of the support element to cost-effectiveness

In a pay as bid auction, the level of the support awarded to each project is determined by the candidates themselves, based on their best knowledge of technology costs at the time of the tender. It also takes into account other subsidies from which candidates may benefit. It is therefore not necessary for public authorities to determine administratively a level of support, which would necessarily be based on an estimation of the costs of production of RES.

In order to contribute fully to cost-effectiveness, the main condition is that sufficient competition applies in the tendering procedure. In a competitive environment, candidates are incentivised to bid at their lowest price, which means to lower their profitability expectation at their minimum level. If this condition is not met, the tender may result in strategic bidding, and the level of support finally awarded may be higher than what would be necessary.

Some tender parameters must also be carefully designed in order to ensure a sufficient level of competition: the total targeted capacity should take into account the potential projects at the time of the tender, and the timeframe of the tender should take into account a sufficient lead-time for potential new entrants to prepare a bid.

More generally, the definition of a multiplicity of selection criteria results in awarding support to projects that may not be the most cost-effective, since a project with a higher price may end up selected if it performs well on other features. The evaluation of qualitative criteria, such as environmental aspects, also increases the complexity of the procedure and may not even result in a better performance of selected projects since they must in any case comply with all applicable regulations. A selection process based solely on the price of the bids should be preferred, as it ensures economic efficiency and relative simplicity of the procedure.

Last but not least, it is crucial to avoid the multiplicity of support schemes for the same type of RES installations: if a FIT applies for installations covered by a call for tenders for instance, the tariff level it sets will most probably define a floor price for bids, degrading the cost-effectiveness of the scheme.

[39] For instance: 2 years for PV, 2 and ½ years for biomass, 8 years for offshore wind.
[40] The level of the penalty would be determined by the Ministry. It cannot exceed 5 €/kW, in the limit of 100 k€.

2. General lessons learnt from the call for tender

Calls for tenders have been mainly resorted to in France for PV, biomass and wind power over the last 15 years. The following table gives an overview of all tenders in these sectors.

Technology	Year	Targeted capacity	Submitted bids	Selected bids
Medium scale PV (100-250 kWp)	2011	300 MW	1488 (303 MW)	697 bids (146 MW)
	2013	120 MW	2232 (457 MW)	591 bids (122 MW)
Large scale PV (> 250 kWp)	2009	300 MW	119 (867 MW)	Tender declared unfruitful.
	2011	450 MW	425 (2,438 MW)	105 bids (519 MW)
	2013	400 MW	396 (1,968 MW)	121 bids (380 MW)
Biomass	2004	200 MW biomass 50 MW biogas	24 (421 MW)	14 bids for biomass (216 MW)
	2007	300MW	56 (692 MW)	22 bids (305 MW)
	2009	250 MW	106 (936 MW)	32 bids (266 MW)
	2010	200 MW	16 (440 MW)	(15 bids (420 MW)
Onshore wind	2005	500 MW	14 (519 MW)	7 bids (279 MW)
Onshore wind with batteries	2010	95 MW	21 (157 MW)	9 bids (90 MW)
Offshore wind	2004	500 MW	11 (944 MW)	1 bid (105 MW)
	2011	3,000 MW	10 (5,214 MW)	4 bids (1,928 MW)
	2013	1,000 MW	4 (1,988 MW)	2 bids (992 MW)

Table 1 – Overview of all tenders carried in France between 2004 and 2013[41]

The reasons for resorting to calls for tenders differ for each technology. They can be used to control the development of a RES technology when FIT proved inefficient in that respect, as was the case for medium & large scale PV, or to take into account acutely local issues for sectors such as biomass of offshore wind. CRE has called several times to extend calls for tenders to other technologies where there would be enough competition to encourage a more robust design and an industrialisation of the sector.

The specific cases of PV and offshore wind tenders are presented and discussed in the following sections, which allow examining different features of the tendering procedure, particularly regarding cost-effectiveness.

3. Empirical evidences from the calls for tenders for PV power plants

The first attempt of a tendering procedure for large scale PV, in 2009, aimed at promoting a regionally balanced development of PV, by awarding one project per administrative region. However, a FIT for large scale installations coexisted at that time, which was already profitable enough, and bidders ask for a price in average 20% higher than the FIT level. As a result, the tender was declared unfruitful, and no project was selected. This example illustrates the economic inefficiency of setting multiple support schemes for a same technology.

[41] Source: CRE.

Since then, calls for tenders have been set up as the main support scheme for medium and large scale PV after the bubble observed in many European countries in 2010-2011. FITs, as an administrative, price-based support mechanism, proved inefficient to adapt to the dramatic decrease in production costs that occurred and to control the total installed capacity.

Calls for tenders for medium scale installations (between 100 and 250 kWp) are conducted through the accelerated procedure, and are usually periodic, which means that one tender defines several bidding periods, giving some visibility to bidders. This type of multi-round tenders proves quite efficient, and would gain to be extended to other tenders. The weighted average price resulting of the consecutive rounds have regularly decreased, as shown in the following figure.

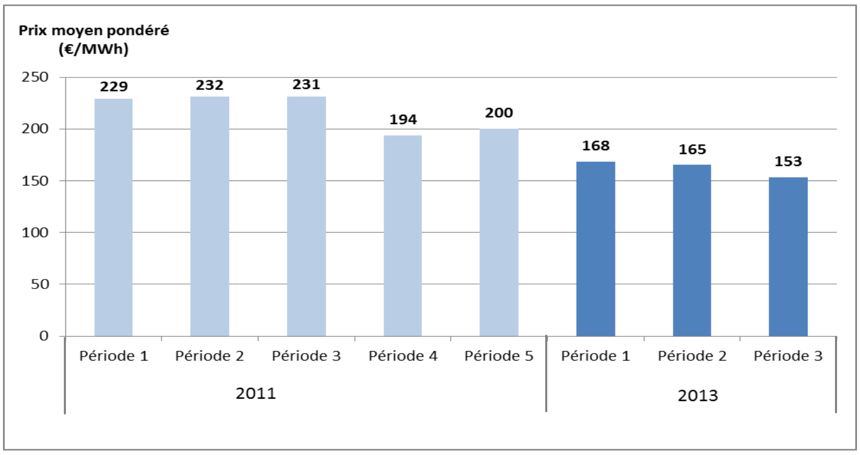


Figure 1: Average support level development over the tendering rounds

The same trend is observed in calls for tenders for large scale installations (over 250 kWp).This result can be explained by the decrease in costs for PV installations between 2011 and 2013. It is also the result of the competitive process, since the total capacity of submitted bids greatly exceeded the target of the tenders. These aspects are illustrated in the following figures, which distinguish the different categories of installations that were targeted in the tenders: rooftop installations, such as parking shelters, ground mounted installations, and solar farms using the technology of concentrated PV.

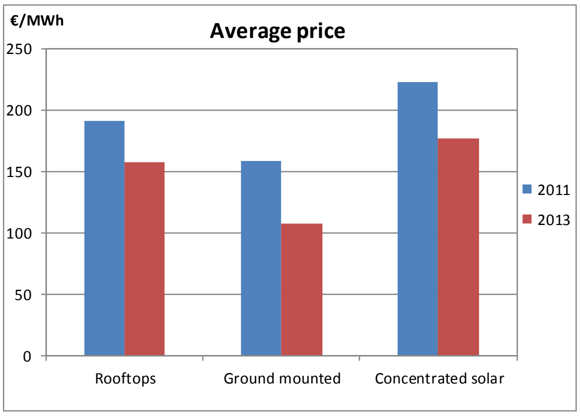


Figure 2: Average support level by PV categories

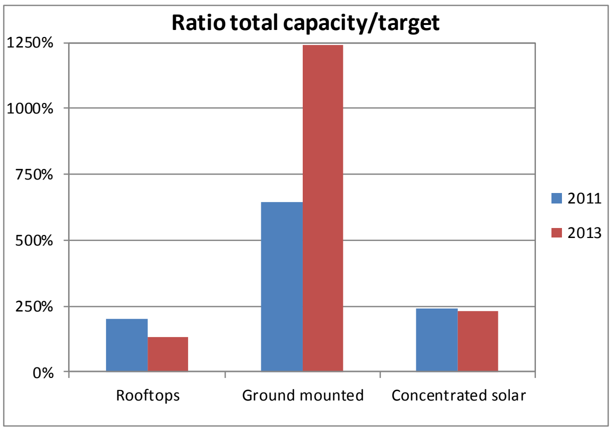


Figure 3: Submitted bids in relation to target

A new call for tenders has been launched in 2014, and the prices are expected to decrease much further, proving the economic efficiency of tenders when sufficient competition occurs.

4. Empirical evidences from the calls for offshore wind farms

A first call for tenders for offshore wind farms was organised in 2004. Bidders could propose any project and were ranked based on an analysis of prices, environmental impacts and potential land use conflict. However, due to the multiple local issues faced by projects, none of them was eventually realised.

In order to achieve its ambitious development target for offshore wind (6 GW by 2020), the government anticipated the launching of a new call for tenders, by setting up a local concertation aiming at defining favourable zones. These zones were usually areas that project developers had already identified. They are shown on the following map.

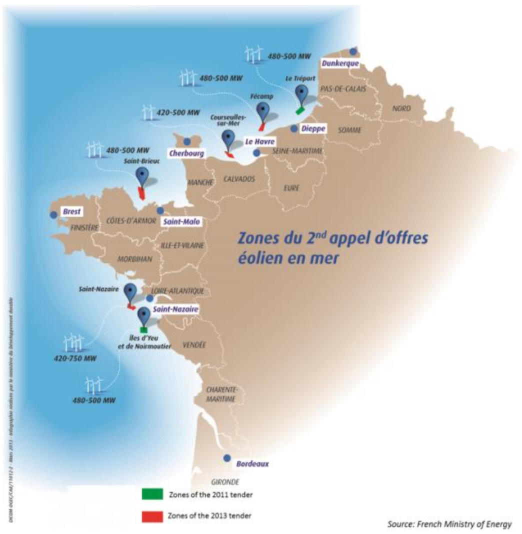


Figure 4: Defined regions for wind offshore projects

The tenders of 2011 and 2013 resulted in prices that were relatively high compared to other European countries, around respectively 220 €/MWh and 200 €/MWh. These high prices can be partly explained by the specific geographic and meteorological conditions of the French coasts, but they are also a result of some of the tenders' parameters which are discussed below.

First of all, the tender specifications imposed a very short lead-time for potential bidders to submit their projects: 6 months in 2011 and 9 months in 2013. Given the complexity of such projects, it was only possible for developers who had already conducted studies on the zones of the tenders to propose competitive bids. The very low level of competition of these tenders, with an average of two bidders per zone, may have led in strategic bidding behaviours, explaining partly these price levels. For one zone of the 2011 tender, only one bid was submitted, which resulted in the government declaring the tender unfruitful for this zone given the lack of competition.

Furthermore, the evaluation of bids was based on a broad range of criteria, such as price, industrial development, environmental impacts and contribution to R&D. A large share of the evaluation was related to the commitment of bidders to build new production plants for offshore wind mills. This willingness to associate the calls for tenders with the development of an industrial cluster is also one of the possible reasons for such high prices to result from the tenders.

Finally, even though the signature of power purchase agreement ensures a very low financial risk for projects, bidders that had already conducted preliminary studies on the zones still bear challenging technical risks. As a matter of fact, the tendering procedure imposes a relatively rigid framework, since bidders are supposed to commission the wind farms compliantly with their project description, even though all technical conditions were not perfectly known at the time bids were submitted. These conditions probably resulted in high risks premiums integrated in bidders business plans, eventually reflected in the price they proposed.

For these reasons, the tendering procedure, as it is currently defined in France, does not appear as the most effective support scheme for such a technology. A scheme that would be supervised by public authorities during the whole process, from the definition of the zones and the carrying out of necessary technical studies to the financing of the projects, seems preferable, as it would result in a more balanced allocation of risks.

5. Role played by the NRA

CRE is involved at several stages of the implementation of the tendering procedure.
Once the government has decided the launching of a call for tenders, CRE is in charge of submitting a proposal of tendering specifications, based on the general conditions defined by the ministry and which describe the targeted capacity (possibly geographically split), the economic conditions applicable to successful bidders as well as potential specific requirements they must comply with, and the selection criteria and their respective weights. The final tendering specifications are adopted by the government.

CRE is then in charge of receiving the bids submitted before the deadline set out in the tendering specifications. It opens the tenders, which consists in making sure that submitted bids are complete, and analyses complete bids based on the selection criteria defined in the specifications, before transmitting the ranking of the bids as well as a detailed analysis of each of the bids to the government.

Finally, CRE issues a formal opinion on the choice of successful bidders that the government intends to make, based on the adequacy of this choice with the ranking of bids.

This procedure guarantees a non-discriminatory treatment of the tendering procedures. However, it appears that the distribution of the roles between the ministry and the regulator can be a source of complexity, especially regarding the redaction of the specification documents

Annex 5 – Overview of quota systems in Europe

MS	General facts	Eligibility of certificates	Buyers of certificates	Market	Financing
Belgium		• All renewable electricity generation technologies • Offshore wind energy and hydropower technologies fulfilling certain conditions can sell certificates to the federal grid operator • Time eligibility: 10 years but it can vary	• Grid operators (TSO and DSO)	• Federal minimum prices for certificates: • Off-shore wind power stations with a rate of 107 EUR/MWh for the first 216 MW built and then 90 EUR/MWh for additional capacity • Hydro-electric power stations: 20 EUR/MWh • Regional minimum prices and penalty systems - Flanders, Wallonia and Brussels	• The cost of certificates are borne by the end-user and financed over the electricity bill
Norway	• Established a market for electricity certificates which, from January 2012, was linked to the Swedish electricity certificate market with a goal to develop 26.4 TWh of new RES production by 2020. • Norway and Sweden are each responsible for financing half of the support scheme, regardless of where the investments take place.	• Support mechanism for all renewable electricity generation (as defined in the RES-Directive) in operation after 7.9.2009 and hydro power plants started construction after 1.1.2004 • One certificate per produced MWh – no differentiation between technologies • Eligibility of support: 15 years	• Electricity suppliers, end-users who buy electricity directly on the wholesale market or for themselves	• Traded on a market - the certificate price is the same for all technologies. • The electricity certificates are valid until 1.4.2036 • Penalty for failing to meet the certificate obligation 1 April: Penalty equals 150 percent of traded prices in the previous electricity certificate period (1 April the previous year to 31 March in the current year)	• The end-users bear the costs for the scheme over the electricity bill.
Poland	• The certificate scheme was established in 2005. • Goal is to achieve a 15 % RES in final energy consumption for renewable energy sources, with a 10 % share of bio-fuels in the fuel market by 2020.	• All technologies based on renewable electricity generation. There are some additional requirements for biomass over 5 MW and 20 MW in terms of the share of biomass. • Eligibility of support: 15 years	• Electricity suppliers must provide evidence of supplying renewable certificates equal to a government-set share of electricity supply to the end user. • All RES energy	• No limitation on participation • The supplier can alternatively pay a government-set substitute price that is calculated annually (2012: PLN 286.74 for each MWh) • Penalty for not meeting the quota obligation: A per-MWh fee which exceeds the substitute price	• The end-users bear the costs of the scheme through the electricity price.

			supplied to the end-user is exempt from excise tax.		
Romania	• The green certificate scheme in Romania came into effect in 2011. • Goal of the scheme is to reach 24 % RES electricity generation of total electricity generated in Romania.	• The electricity certificate scheme is technology-neutral, i.e. all forms of renewable electricity are entitled to electricity certificates, including hydropower, wind power, solar and bioenergy. • The number of certificates issued per produced MWh may differ between technologies. It ranges from 6 certificates per MWh generated electricity from solar power to 1 certificate per 2 MWh produced from old hydro power plants. • If a plant is supported under an investment scheme, the number of certificates received per MWh may be reduced. This is evaluated on a case-by-case basis. • Eligibility of support: 15 years	• Suppliers and producers	• Traded on a market - The certificate price is the same for all technologies. • The green certificates are valid for 12 months. • The transaction value of one green certificate will be at least 27 Euros and at maximum 55 Euros, inflated yearly. • Penalty for failing to meet the certificate obligation 15 April: supplier will be obliged to purchase the missing certificates at EUR 110 per certificate and inflated yearly, which is paid to an environment-fund set up by the government.	• The end-users finance the scheme through the electricity price.
Sweden	• Established a market for electricity certificates in 2004, which, from 1 January 2012, included Norway. The common goal of the electricity certificate market is to develop 26.4 TWh of new renewable energy production by 2020. • Norway and Sweden are responsible for financing half of the support scheme each, regardless of where the investments take place.	• Support mechanism for all renewable based electricity generation in operation after 2004 • One certificate per produced MWh – no differentiation between technologies • Eligibility of support: 15 years	• Electricity suppliers, end-users who buy electricity directly on the wholesale market or for themselves	• Traded on a market - The certificate price is the same for all technologies. • The green certificates are valid until 1.4.2036 • Penalty for failing to meet the certificate obligation 1 April: Penalty equals 150% of traded prices in the previous certificate period (1 April the previous year to 31 March)	• The end-users bear the cost of the scheme over the electricity bill.

UK	• Renewables Obligation (RO) scheme established in 2002 • Aim is to increase the proportion of electricity from renewables that suppliers sell to customers each year • Driven by decarbonisation targets • Scheme administered by Ofgem (GB energy market regulator)	• Various technologies eligible under RO including onshore & offshore wind, bio fuels, hydro, PV, wave and tidal. • Operators of generating stations receive certificates from Ofgem for the renewable electricity their stations generate. Different technologies receive different numbers of certificates per MWh generated. • Support for the stations generally lasts for 20 years from date of accreditation • Suppliers then have to present certificates and/or make payments to demonstrate they have met their obligations each year	• Suppliers bear the end obligation so they are the main buyers for certificates	• Certificates can be traded on an open market • Most trading is between suppliers and generators but sometimes other parties get involved, e.g. brokers who will buy ROCs and sell them at auction • If suppliers make payments towards their obligations, they do this at a price per ROC that Ofgem adjusts each year in line with inflation. This is not a 'penalty' but simply another means to meet their obligation. This money is then redistributed by Ofgem to suppliers in proportion to the number of certificates they presented	• The end-users bear the costs of the scheme through their electricity bills.

Source: RES legal.

Annex 6 – CASE STUDY on the Norwegian Swedish electricity certificate system

The Norwegian Water Resources and Energy Directorate (NVE) and the Swedish Energy Authority are the administrative and supervisory authorities for the electricity certificate scheme in Norway and Sweden. In 2012, the joint Norwegian-Swedish electricity certificate scheme replaced the national investment grant schemes: Energy Fund in Norway and the national electricity certificate market in Sweden. The joint certificate scheme has become the principal instrument to reach RES targets in both countries.

The electricity certificate scheme is intended to boost renewable electricity production in both Norway and Sweden. The common electricity certificate market is an example of a so-called collaboration mechanism under the EU Renewable Energy Directive. The countries have a joint goal of increasing electricity production based on renewable energy sources by 26.4 TWh from 2012 to 2020. Norway and Sweden are responsible for financing half of the support scheme each, regardless of where the investments take place. The target for increased renewable electricity production can thereby be achieved in a more cost-effective manner, since that investment will be directed to where conditions are most favourable. Both countries are credited with an equal proportion of the increased renewable energy production in relation to the 2012 level when reconciling with the countries' targets for 2020.

Sweden introduced a national certificate market in 2003 in an effort to increase energy security and it was emphasised that increased production from renewable electricity could be important to Sweden's national actions on climate change mitigation.

Norway has, since the electricity certificate system was first evaluated (Stortingsmelding nr 9 2002-2003), been positive to enter an international electricity certificate scheme and highlighted that it could lead to an harmonised framework for renewable electricity production in an international power market.

The agreement between Norway and Sweden on a common market for electricity certificates was signed 29 June 2011. It sets out the purpose of the electricity certificate system and how the market is to function for the period of 2012 to 2035. In spite of the market being in common, each country has national laws and regulations that regulate the electricity certificate system in that country. The Norwegian Electricity Certificates Act (2011:1200) came into effect 1 January 2012.

Both countries observe that the electricity certificate scheme has led to higher than expected investments into electricity generation based on renewable sources of energy. Hence the certificate system is so far deemed successful, and is believed to reach its target of 26.4 TWh of new electricity production within 2020 in a cost-effective manner.

1. Key features of certificate schemes

In the following chapter, the key features for setting up a certificate system will be described.

1.1 Determining the quota

The quota is set as a share of the volume of electricity to be financed and final electricity consumption in Norway. The statutory quota in Norway is reviewed periodically in terms of reaching the joint target of 26.4 TWh in 2020.

The quotas, which are defined in legislation on electricity certificates, gradually increase until 2020, which causes increasing demand for electricity certificates. The quotas are specific to each country. Norway's quotas run from 2012 to 2035. Sweden's quota curve is from 2003 to 2035.

The quota curves are designed to stimulate the development of renewable power production in accordance with the countries' established targets. The respective countries' quota curves are calculated and set based on assumptions of future calculation-relevant electricity consumption. If the actual calculation-relevant electricity consumption deviates from expectations, this may mean that the quota curves must be adjusted so that cancellation can occur in accordance with the agreement between countries. The first adjustment is to occur in connection with the progress review in 2015. Such an adjustment of quotas does not mean any change in the target of 26.4 TWh in increased renewable power production.

1.2 Issuing of electricity certificates

A power producer applies to the Norwegian Water Resources and Energy Directorate (NVE) or the Swedish Energy Agency to have its plant authorised for the issuance of electricity certificates. Applications for approval are sent to NVE for power stations in Norway, while for power stations in Sweden, the application is sent to the Swedish Energy Agency. A power station cannot be authorised for the issuance of electricity certificates until the application is completed and the power station is in operation. The Norwegian or Swedish state issues electricity certificates to power producers for each megawatt hour (MWh) they produce. The electricity certificates can thereafter be sold and the producer will receive extra income in addition to the electricity price.

Electricity certificates are issued on the 15th of each month, based on the power production in the previous month reported by grid owners and power producers with responsibility for reporting the metered values. Certificates are issued to the producer's electricity certificate account in the Norwegian or Swedish electricity certificate register: NECS or Cesar respectively.

New plants and production increases in existing plants are entitled to receive electricity certificates for 15 years, although not after the end of 2035, when the electricity certificate system expires. The total number of electricity certificates issued is determined by power production in the approved plants. In combined heat and power plants, the number of certificates is also affected by the proportion of renewable fuel. External factors such as temperature, rainfall, wind and power prices also affect power production and thereby the issuing of electricity certificates.

1.3 Trading of electricity certificates

Trading in electricity certificates occurs on the electricity certificate market, where the price is determined by supply and demand. The common market makes it possible to trade in both Swedish and Norwegian electricity certificates. Trading occurs through bilateral agreements between power producers and market participants with quota obligations, as well as via brokers. Both power producers and market participants with quota obligations must have an electricity certificate account. Swedish participants have electricity certificate accounts in Cesar, while Norwegian participants have accounts in NECS. When traded, electricity certificates are transferred from the seller's to the buyer's account.

Electricity certificates are mainly traded in two types of contracts: spot price contracts and forward contracts. For both types of contracts, the price of electricity certificates is set on the date of the agreement. The main difference between the contract types is the date of transfer of and payment for the electricity certificates. With forward contracts, transfer and payment occur on a specified future date, while with spot price contracts the certificates are paid for and transferred within five and ten working days respectively.

1.4 Cancellation of electricity certificates

Each year, market participants with quota obligations must notify NVE or the Swedish Energy Agency of the number of certificates they need to fulfil their quota obligation and have that number in their electricity certificate accounts. Swedish market participants with quota obligations do this by sending a declaration of their quota obligation to the Swedish Energy Agency. Norwegian market participants with quota obligations approve the quota obligation that is presented in NECS.

In order to fulfil the quota obligation, the market participants with quota obligations must have certificates corresponding to the statutory proportion of their calculation-relevant electricity consumption in their electricity certificate accounts. The certificates are annulled on 1 April, which means that the electricity certificates are cancelled out and cannot be re-used. Cancellation means that market participants MWh with quota obligations must buy new electricity certificates in order to fulfil next year's quota obligation. This creates a constant demand for electricity certificates.

1.5 Financing of the certificate scheme

Power suppliers pass on the costs of electricity certificates to the end-users through the electricity bill. In this way power customers in Sweden and Norway help to pay for the development of power production from renewable energy sources. Power-intensive industries have an electricity certificate cost linked to their electricity consumption that is not used in production processes.

Even though Sweden and Norway are to finance an equally large amount of their common target, the cost per kilowatt-hour (kWh) is different. This is because power generation capacity built before 2012 is financed by the respective countries. Different certificate quotas mean that the cost per kilowatt-hour is different in the two countries, even though the electricity certificate price is the same.

2. Role played by NRA

The responsibility for administrating the scheme in the joint Norwegian-Swedish electricity certificate market is shared by the respective national regulators. Each country is responsible for ensuring that players in respective countries follow national regulation. The NRA in each country is also is responsible for ensuring that the market functions well.

3. Lessons learnt from the certificate system

The joint electricity certificate scheme started in 2012 and is now four years old. The perhaps most important lesson learned so far is that it takes time to establish a governing framework for an international electricity certificate system. There are many issues that need to be dealt with. These include for example rules regarding entitlement of electricity certificates, tax, existing national support mechanism, overall target, electricity certificate obligation and setting of quotas, exchange of information between countries and so forth.

The electricity certificate scheme is as many other support mechanisms exposed to political and regulatory risks despite being a market based instrument. The electricity certificate market is politically constructed, and the rules governing the mechanism can therefore change. However, any changes that affect the joint market must be agreed on by both countries, which limit this risk. In addition, both countries have agreed to limit any changes to the rules to predefined periodic reviews that usually occurs every fourth year. This contributes to mitigating the regulatory and political risk.

This system is intended to increase power production from renewable energy sources in a cost-effective manner. This implies that investors must have complete information on how cost-effective its power plant is compared to other projects being considered for investment in the system. Both Norwegian and Swedish Energy Authorities have worked towards improving the information exchange across borders on projects under construction in both countries in order to provide investors with better foundation for decision making.

In theory the electricity certificate price is negatively correlated to the electricity. This implies that lower electricity prices should increase the electricity certificate price. This relationship has not so far been observed in the joint electricity certificate market. There can be many reasons why this theoretical relationship does not hold. One often cited reason is that the market of electricity certificates is more concerned about the short term number of certificates in circulation rather than the long term deficit towards 2020.

- ***Consumers' perspective***

  Norway and Sweden are each responsible for financing half of the new production in the certificate system, regardless of where the new production capacity is established. The Swedish and Norwegian power grid is closely interconnected.

  The Swedish and Norwegian power grid is closely interconnected. Retail prices are closely linked to wholesale prices. In effect, increased power supply in one country reduces power prices in both countries. So far prices of electricity for consumers have decreased more than the costs of certificates borne by end-users have increased.

- ***Producers' perspective***
  In the electricity certificate system, markets have developed to hedge both electricity certificate price and the power price. In other words, a producer can secure its long term revenue streams through market instruments. The system is designed in such a way that the decision to secure a revenue stream is left to the producer.

- ***Technological perspective***
  The electricity certificate scheme is designed to bring commercially competitive technologies on the market. In other words, it does not promote research and development into immature technologies, nor does it promote early stage technologies.

4. The way forward

The common Swedish and Norwegian electricity certificate market have per by the 3rd quarter 2015 built 12.9 TWh of new renewable electricity production capacity since 2012. This is in line with the set trajectory to introduce 26.4 TWh by 2020. Norway and Sweden have predefined progress reviews. Under the current progress review (2nd) the two governments are assessing the possibilities of extending the electricity certificate system. They are specifically reviewing the technical adjustments needed in the case of just one country extending within the electricity certificate system.

Annex 7 – Overview of FIP in the MS

Country	Type of premium	Premium calculation methodology (in case of floating premiums)	Possibility of negative premium?	Calculation methodology of reference market price	Premium for auto-consumption?	Handling of negative market prices	Eligibility period
Czech Republic (SUPPORT SUSPENDED FOR NEW RES POWER PLANTS!)	Floating	**Yearly premium**: it should cover at least the difference between the feed-in tariff for given technology and the expected yearly average of hourly day-ahead power market prices **Hourly premium**: it should at least cover the difference between the feed-in tariff and the actual hourly day-ahead market price	No	In the case of the yearly premium, the reference market price is the average of the hourly day-ahead market prices	n/a	If the hourly market price is negative, it is counted as zero (so the premium equals the feed-in tariff)	20 years (hydro power plants: 30 years)
Denmark	Fix or floating, in some cases balancing bonus and extra bonus	Premium=maximum price – reference market price	No	Hourly spot market price on the Nordpool spot market, for given territory In case of wind power plants commissioned after 20.02.2008: monthly average market price, which is the weighted average of wind power production and spot market prices	Yes, wind power plants with max. 25 kW capacity and solar power plants up to 6 kW capacity	In case of the Anholt wind farm, no premium is paid in those hours when the market price is not positive	Technologically differentiated, 10 or 20 years
Estonia	Fix	-	No	-	No	-	12 years in general
Finland	Floating	Generally premium=basic price – reference market price In case of timber chips, the premium depends on emission allowance costs and peat tax (see Table 3)	No	The average market price for electricity is calculated as an arithmetic mean of the three-month hourly prices for the three months corresponding to each tariff period.	No because auto-consumption is already supported by its exemption from power taxes	In case of negative market prices no premium is paid (not yet happened in practice)	12 years
Germany	Floating (but fix for a month)	Premium calculated each month as follows: Premium = fix technology specific reference value) – average monthly technology specific market price	No	Not intermittent technologies: monthly average of hourly EPEX spot prices Intermittent technologies (wind, solar): power production weighted monthly average of EPEX spot prices	No	If market price is negative in at least 6 consecutive hours, the reference value is zero (this is valid for new RES power plans from 2016 but there	20 years

Country	Type of premium	Premium calculation methodology (in case of floating premiums)	Possibility of negative premium?	Calculation methodology of reference market price	Premium for auto-consumption?	Handling of negative market prices	Eligibility period
						are some exceptions)	
Italy	Floating	Premium=feed-in tariff for given plant category + other support elements – hourly power market price for given price zone	No	Hourly power market price for given price zone	No	In case of negative market prices, the reference market price is counted as zero so as the premium is equal to the sum of the feed-in tariff and other support elements	20 years in general but for offshore wind power plants, it is 25 years and for hydro, wave and tidal power plants, 15 years
Netherlands	Floating	Premium=basic price – correction factor (reference market price)	No	In general the unweighted yearly average of APX day-ahead hourly market prices; In case of wind power plants, hourly market prices are weighted with wind power production values; In case of solar power plants, the unweighted average of the day-ahead market prices of the hours 8-23	In case of biomass technologies from February 2013	-	Generally 15 years, but for biomass and biogas plants the support period is 12 years
Slovenia	Floating	Premium=reference price – estimated average market price*B factor	No	Yearly market price forecasted by the Slovenian Energy Agency = EEX Phelix Baseload Year Futures next year average + annual Auction Price for cross-border transmission capacity on the border between Slovenia and Austria	Yes if the cost of electricity generation is higher than the power price which can be realised on the market	-	15 years
Spain (SUPPORT SUSPENDED FOR NEW	Floating (special)	Operational support counted for benchmark power plants, based on different parameters	No	In 2014, 2015 and 2016, average wholesale power market prices are counted as a yearly average of the OMIP baseload futures contracts. From 2017,	No	Rules of the Spanish wholesale power market prohibit negative market	Support is granted for the full time of

Country	Type of premium	Premium calculation methodology (in case of floating premiums)	Possibility of negative premium?	Calculation methodology of reference market price	Premium for auto-consumption?	Handling of negative market prices	Eligibility period
RES POWER PLANTS!)				the estimated average market price is 52 EUR/MWh.		prices.	expected 'useful regulatory life' of power plants, in function of ROI.
United Kingdom	Floating	Premium=strike price (maximum price) – reference market price	Yes, if the reference market price exceeds the strike price	Baseload technologies: calculation is based on forward market baseload prices Intermittent technologies: calculation based on day-ahead hourly market prices (for more details, see Chapter 2.10)	No	From 2016, no premium is paid for more than 6-hour long negative price periods	15 years

Source: RES-Legal and consultation with MS.

Annex 8 – CASE STUDIES on Feed-in Premium schemes in Germany and in the UK

1. The German Market Premium scheme ("Direktvermarktung mit gleitender Marktprämie")

The German market premium scheme has been introduced as a new element in the 2012 revision of the Renewable Energy Sources Act (EEG). Up to 2012, fixed Feed-in Tariffs (FITs)[42] were the only form of financial support granted to RES plant operators[43]. The market premium scheme (Feed-in Premium/ FIP) has first been conceived as an alternative form of financial support for RES plant operators for "experimenting" the market on a voluntarily basis. However, since August 2014, it is in principle mandatory for all RES operators of newly installed plants above 100 kW (until end of 2015: 500 kW) to sell their electricity on the market under the Market Premium scheme, when intending to claim a financial support. *De-minimis* provisions were introduced for RES installations smaller 100 kW.

The German Government has committed to progressively achieve an 80% share of RES in electricity production by 2050. In 2012, RES based electricity amounted to 24% of electricity consumption (2014: 27.4%). The FIT scheme has been very successful in inducing this large scale deployment of RES technologies. However, FITs fully shielded RES operators' operational activities from the market posing serious challenges to the whole system, once RES producers started to grow considerably in number. By 2012, 1.5 million RES operators (mainly of small PV installations) were feeding their electricity produced into the network independently from market price developments. An adaptation of the support scheme was inevitable to integrate the increasing number of RES producers into the market and to link their investment and production decisions to market price developments. The introduction of a market premium scheme, first on an optional basis and later as an obligation, was the answer to the challenge of market integration. This approach allowed RES producers (and policy makers) to gain experience with the new instrument from 2012 onwards and ensured a rather smooth transition between the different support schemes.

1.2 Key elements of the market premium model

(1) Objectives of the scheme

One key objective of the market premium scheme is to endow RES producers with an active role in the electricity market and to be subject to market risks linked to short term price fluctuations and balancing responsibilities. This is a major change compared to the observed "produce & forget" approach under a FIT scheme. RES producers should have an economic incentive to link their production pattern to the market prices to perform better than the average. Entrepreneurially skilled RES producers have the opportunity to improve their income compared to a fixed income stream under a FIT scheme, while RES producers taking wrong economic decisions will be facing (limited) losses.

Following from the orientation of RES producers towards a market-driven production pattern, the overall system is likely to benefit from a more demand-oriented electricity production.

[42] The FIT are technology specific and guaranteed for 20 years (in addition to the year in which the RES installation is taken into operation).
[43] Only financial support granted in the context of the EEG Framework.

(2) Basic functionality

In the market premium scheme, RES plant operators are obliged to sell, directly or through a third party, their electricity produced and fed into the grid on the market place, in order to claim a support entitlement defined as a market premium. In this scheme, RES plant operators have two income streams:

- One is provided by the market (e.g. day-ahead, intraday). The value is determined by the quantity sold and the market price achieved; and
- a second, the market premium, is determined individually for each RES producer.

The market premium is calculated ex-post and on a monthly basis as the difference between a installation-specific reference value determined in accordance with the EEG 2014[44] and the average technology-specific monthly market value. The market value is calculated by the four TSOs and published on a RES dedicated internet platform[45]. The basic formula for calculating the market premium is: $\mathbf{MP = RV_{RES\ installation} - MV_{RES\ technology\ i}}$ with
MP = Market premium
RV = RES technology specific reference support value[46]
MV = Average monthly technology-specific market value
and i= wind power, solar power, hydro, biomass or geothermal

The functionality is described in the graph below:

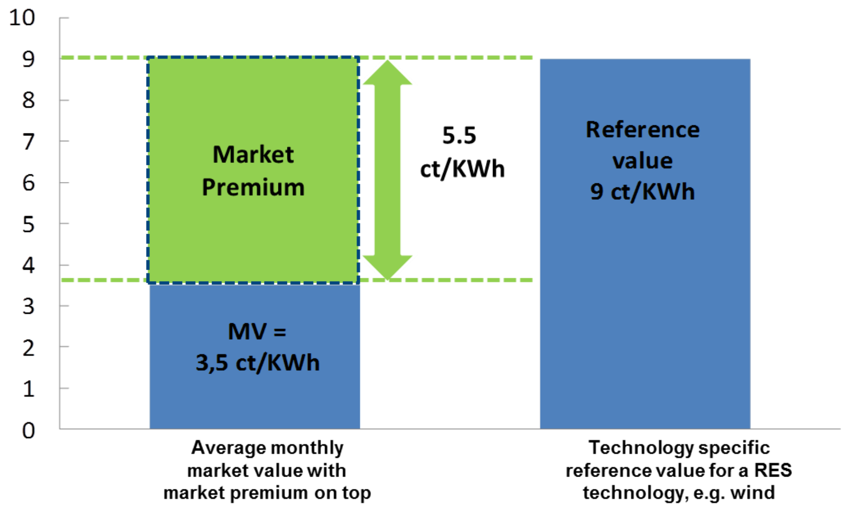


Figure 1: Functionality of the premium scheme "Direktmarketing"

[44] For each RES technology, the reference support value ("anzulegender Wert") is set based on the rules defined in the EEG, i.e. RES operators have full transparency regarding the level of support they are entitled to, when going into operation. Operators of the same RES technology and of the same size, and going into operation at the same time within a given time frame (depending on the technology, 1 month, 3 month or one year) would be entitled to the same support level (for wind, the location will play an additional role in the level of support). The reference support value remains unchanged for the duration of the support, e.g. 20 years.

[45] Under the EEG, TSOs are obliged to provide a transparent platform on which information about the wholesale prices, forecasts about expected hourly RES feed-in, etc., is published. See www.netztransparenz.de.

[46] See footnote 35. The reference support value is technology specific and to some extent also installation specific, as it is adapted in regular time intervals for new installations. As a result, RES installations of the same size and technology can be entitled to different reference support values when starting operation at different times.

The premium scheme differentiates between intermittent RES technologies such as wind and PV and dispatchable, non-intermittent ones such as hydro, biomass (incl. landfill, sewage and mining gas) & geothermal:

- For the **non-intermittent RES technologies**, the average market value, expressed in cent per kWh, is calculated as the monthly arithmetic average spot price (at the EPEX spot exchange); and

- **For wind (onshore & offshore) and PV**[47] a different approach has been chosen as the market value derived from an arithmetic monthly average does not properly reflect the income these RES technologies can actually earn from the spot market. In fact, as wind/PV installations frequently produce synchronously, market prices tend to be lower, hence deriving a lower average market income as dispatchable RES installations. Especially wind producers face the lowest average market incomes, as they frequently produce during night hours, where market prices are at their lowest level.[48] Against this background, the market value for wind and PV electricity is a production-weighted monthly average.

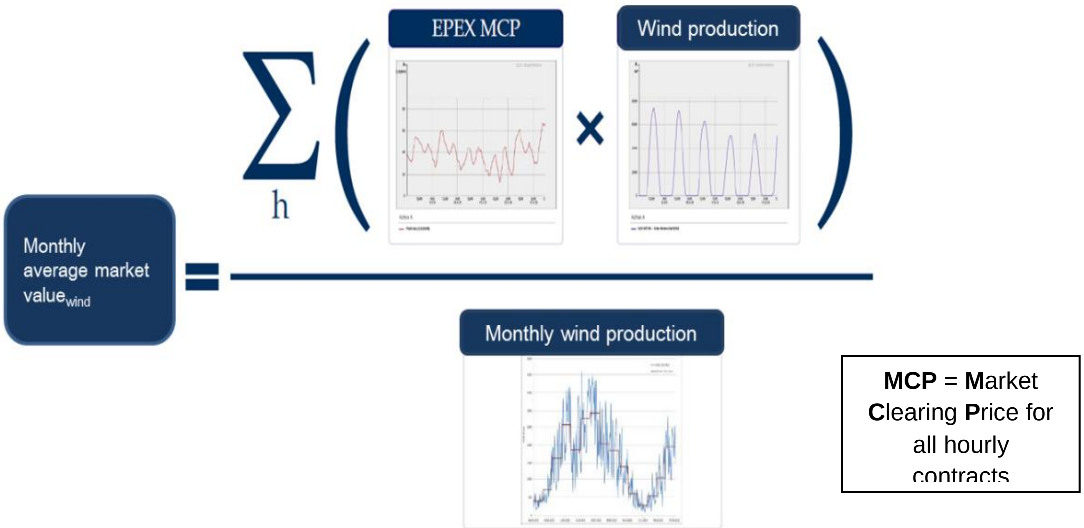


Figure 2: Calculation of the market value for wind (adapted from Energy Brainpool)

In the (today) unlikely situation in which the average monthly market value would exceed the RES specific reference value, RES producers do not have to pay back the difference value.[49]

The information about the value of the hourly contracts at the EPEX Spot, the extrapolation of the RES electricity produced and the RES specific market values are published by the TSOs on a dedicated website[50]. The RES installations falling under the premium scheme receive on a monthly basis the premium payment by the respective DSO to whose network

[47] See Annex 2 to the EEG 2014.
[48] For example, in May 2015, the average monthly market values for the different RES technologies where 2.268 ct/kWh for wind, 2.511 ct/kWh for PV and 2.536 ct/kWh for dispatchable RES. See http://www.netztransparenz.de/de/Marktwerte.htm.
[49] This is one key difference to the Contract for Difference scheme in the UK, where RES producers would have to pay back the difference in case the wholesale price is higher than the strike price. See case study on the FIP in the UK (Annex 8.2).
[50] See www.netztransparenz.de.

they are connected. Although the premium value changes every month, reflecting average market prices, it remains a fix value for the period of a month. With this approach, RES producers have to bear a short term price risk (within the month) while being shielded from longer term price risks.[51]

(3) Setting of the reference support value

Under the EEG 2014, all RES installation-specific reference values are defined in the law, e.g. they were set administratively based on in-depth market studies (see chapter 4.1). They are set according to the technology, the size of the installation, and for wind installations, also according to the quality of the location. Since 2015, the reference values for ground mounted PV systems are determined through a pilot tendering process.[52] From 2017 onwards, it is foreseen to determine the reference values for other selected RES technology through tendering procedures.[53]

(4) Regular adaption of the reference support value

The application of the premium scheme does not affect the overall framework of the support scheme laid out in the EEG 2014. The reference value is the basic indicator for calculating both the support entitlements under the FIT (until 2014 and for new small installations falling under the de-minimis clause) and the market premium scheme. For every RES installation the reference value is determined once and then fixed throughout the support period[54] (in general 20 years + installation year).

The reference values as such are adapted on a regular basis, e.g. monthly for PV, quarterly for onshore wind and biomass, and on a yearly basis for hydro, geothermal, and sewage, landfill and mining gases. Hence reference values for new RES installations will always be different (generally lower) than those for already existing installations. In addition, reference values for wind, PV and biomass are also adapted according to their effective yearly deployment, i.e. the regular downward adjustments can be further strengthened or softened, and even corrected to increase support levels[55], depending on the extent to which the limits of their respective deployment corridors[56] are undercut or exceeded. Through the

[51] The choice of the time period defined for reflecting the average market prices is crucial for determining the level of price risk RES producers will be facing in a premium scheme. Determining the premium as the difference between the reference value and the market price on an hourly basis would confront RES producers only with very small market price risks, as this scheme would be the equivalent of a FIT. On the contrary, choosing a longer period like a year as a basis for determining the market average price would translate into substantial price risks for RES producers. The German premium scheme has opted for the middle way, setting the period for determining the average market price as a basis for calculation the premium level to a month.

[52] First round of the tendering procedure started on 15 April 2015. In total, three tendering rounds in two years are planned for achieving a total of 500 MW of newly installed ground mounted PV capacity.

[53] Designing renewable energy tenders for Germany- Executive Summary of Recommendations, Ecofys & al, July 2015

[54] For most RES technologies, support is guaranteed starting the year in which the installation started operation plus 20 years. For wind offshore there is an initial (higher) support paid out for 12 years and a basis support paid out for the remaining 8 years.

[55] For example if the deployment corridor for PV is exceeded by a certain volume, the regular monthly reduction of 0.5% is further increased to 1%, 1.4%, 1.8%, etc., depending on the magnitude of the excess (up to 900 MW,+900 MW, etc.) . In cases where the corridor limits are undercut, the degression can be reduced (from 0.5% to 0.25% or 0%) or even replaced by an increase (+1.5%) in support.

[56] The annual deployment corridors are defined in the EEG 2014: e.g. for wind onshore and PV: 2400-2600 MW and for biomass maximum 100 MW. See § 28-32 EEG 2014.

introduction of these so called “breathing caps”, RES deployment can be better steered by linking the level of support to the observed deployment path.

(5) Balancing responsibilities for RES producers

In the framework of the market premium scheme, RES producers are subject to the same balancing responsibilities as any conventional electricity producers active on the market. In practice, being balancing responsible implies the following duties for RES producers:

- Forecasting RES production;
- Organising selling activities on the market;
- Organising alternative capacities for unexpected changes in weather conditions;
- Bearing financial settlement costs in cases of mismatch between their forecasts and their electricity volumes effectively fed into the grid.

As such, RES producers have an incentive of optimising their forecasting abilities (if not outsourced) to minimise balancing costs. The activities of forecasting, selling and organising alternative capacities can obviously be outsourced to commercial service providers, so called „direct marketing“ companies, specialised in the selling of RES on the market. For covering the extra costs linked to their integration in the market, the reference support value, which is the basis for calculating the market premium, is set 0.2 ct/kWh higher for steerable RES technologies and 0.4 ct/kWh higher for non- steerable RES technologies (wind power and PV) than the support level would be under the FIT scheme for the equivalent technology.

(6) Technical requirements for claiming the market premium

For claiming a market premium, RES producers have to ensure that their installation display specific technical functionalities to ensure that they can be remotely steered by the direct marketing company to which they sell their produced electricity and by the DSO they are connected to. These technicalities ensure that the company offering the RES electricity on the spot market has at any time the possibility to follow the feed-in status of the installation and when needed adapt the feed-in pattern remotely.

(7) De-minimis clause

The legislator has introduced a de-minimis clause to the market premium model to further ensure the deployment of small scale RES installations, mainly rooftop PV systems on private homes, and through this mean, the public acceptance for the energy transition.

(8) Treatment of negative prices under the market premium scheme

Whenever the value of the hourly contracts at the day ahead EPEX spot market is negative for a period of at least six consecutive hours, then all RES specific reference values for the whole period are set to zero. In those hours the value of the market premium is also set to zero.[57] This newly introduced requirement will only come into effect for RES installations starting operation in 2016. The ministry is currently investigating how to best implement this new provision in practice.

[57] See § 24 in combination with Annex 1 (1.2) EEG 2014.

1.3 Lessons learnt from the introduction of the FIP scheme

The market premium scheme has been first introduced on an optional basis in 2012. RES producers opting for this system as well as all stakeholders involved in this system change, e.g. direct marketing companies as well as the ministry in charge of its design had a learning period of roughly two years for gaining relevant experience with it. The following preliminary assessment can be made of the scheme:

- **Large acceptance of the scheme by RES producers**: Between 2012 and 2014, the installed capacity of RES installations falling under the optional market premium scheme increased by 54%, making a share of 52% of total installed RES capacity and 63% of RES electricity produced in 2014. Mainly wind and biomass producers opted for the market premium scheme on a voluntarily basis. From this perspective, the FIP scheme including a generous 'direct marketing' bonus has been very effective in incentivising RES producers to become active participants in the market.

- **Alignment of risk level between RES and conventional producers**: RES producers bear the same balancing risks as any other market participant. Beyond balancing risks, they are also confronted with a range of other risks linked for example to financing, running their installation (maintenance needs) and the availability of their production factors. However, they are only confronted with a monthly price risk, while being shielded from medium to longer term price risks. With the FIP, market risks for RES producers are coming close to the one borne by conventional electricity producers.

- **Incentives for cost-optimising RES generation**: While FIT schemes promoted a "produce-and-forget"-behaviour, the FIP framework introduces small incentives to optimise RES generation in accordance to market signals leading to higher overall cost-efficiency. The optimisation is achieved through e.g. improved forecasts, adjustments in production and maintenance schedules in accordance to market signals and by upgrading technological features of the installation.

- **Emergence of new business models**: Since RES producers can also outsource the marketing activity to a third party, the introduction of the FIP scheme incentivised new business models, e.g. specialised in aggregating RES production from a variety of RES installations to sell it on the market or in providing qualitative forecasting services. The diversification of responsibilities derived from the integration of RES producers on the market has led to more efficient marketing strategies and significant improvements in the quality of forecasts.

- **Emergence of new trading products on the spot market**: EPEX spot has introduced new short term trading products based on 15-minutes-tranches, more accurately reflecting the specific RES-production patterns. Short term trading products allow for a deeper participation of RES producers (or direct marketing companies) on the intra-day market, taking into account RES features linked to intermittency and resulting forecasting needs.

- **Effective transition towards unsupported RES:** The FIP scheme forces RES producers to gain relevant skills for a successful participation in a market setting. These experiences gained under the FIP scheme will be very valuable for all RES producers intending to remain in the market, once their support entitlement has expired.

1.4 Role played by NRA in the FIP scheme

The national Regulator, the Bundesnetzagentur, is in charge of supervising the financial transactions between the different stakeholders (TSOs, DSOs, RES producers) involved in the FIP scheme. In case of initial suspicion regarding any unlawful application of the scheme, the Bundesnetzagentur could intervene.

The NRA further determines the regular reduction rates for the reference support values (as basis for the calculation of the market premium) according to the information collected on the deployment corridors.

The NRA was involved as an expert in the design process of the FIP scheme.

2. The GB Contract for difference (CfD) under Energy Act 2013

The UK Government has committed to reducing UK greenhouse gas emissions by at least 80% by 2050 (relative to 1990 levels), and has placed a strong emphasis on increasing the UK's share of renewable generation to meet this target. This emphasis is demonstrated by a number of government commitments and targets on the development of low-carbon energy. This includes a GB target of producing 20% of energy from renewable sources by 2020 and a public commitment[58] of generating 30% of electricity demand from renewable sources by 2020[59].

In December 2010 the UK Government consulted on its preferred EMR package proposals[60], which included discussion of a wide range of policy proposals; including low carbon price support, emissions performance standards and capacity mechanisms. The consultation recognised the role of a RES support mechanism in delivering the Government's environmental agenda, and included a FIT with a CfD in its preferred package.

Regarding options considered for RES support, three main interventions were offered in the consultation:

- **Feed- in Tariff approach:** Three variations of FIT were discussed, a fixed FIT (as is the case for Spain), a premium FIT (as is the case for Germany) or a FIT with CfD (similar to the 'sliding premium' in place in the Netherlands).
- **Supplier obligation:** This approach would place an obligation on suppliers to source a certain quantity of electricity from renewable sources – or pay a buy-out price. In essence, this would be an extension of the existing support mechanism (RO) to nuclear and Carbon Capture and Storage (CCS).
- **Regulated Asset Base (RAB) model:** This approach, often used as a price control mechanism for natural monopoly utilities (such as DNOs and TSOs), provides a credible commitment to the recovery of the sunk costs associated with capital investment by RES generators.

[58] https://www.gov.uk/government/speeches/statement-on-ending-subsidies-for-onshore-wind
[59] Due to their abundance of renewable resource, the Scottish Government has established a target of 100% electricity demand from renewable sources, which will apply in Scotland only.
[60] Department of Energy and Climate Change (DECC) – Electricity Reform Consultation Document, December 2010.

A summary of UK government's assessment of low carbon support options in the EMR consultation is provided in the table below. On balance, the CfD approach was considered to be most aligned with the government aim of providing a cost-effective support mechanism that provides certainty to investors, at minimal cost to consumers.

Proposed option		Advantages	Disadvantages
FIT approach	**Fixed FIT**	• High degree of revenue certainty • Used widely amongst member states – may make oversee investment more attractive • Simple to implement • Transferring some risks from generator to government may limit barriers for new market entrants – improving wholesale market liquidity	• Goes against government agenda of market based energy policy • All electricity price risk (short and long term) and offtake risk transferred from generators to Government • Difficult to ensure remuneration is cost reflective – strong potential for over or under compensation
	Premium FIT	• More market based than fixed FIT approach i.e. premium dependent on wholesale price • Practically, a premium FIT approach is the closest FIT approach to the current RO scheme, minimising risk of investment hiatus (compared to other FIT approaches) • Simple to implement, with added advantage over fixed FIT that it is more difficult to 'game' the system.	• Less revenue certainty for RES generators as generators exposed to both short and long term electricity price risk. This may act as a barrier for smaller companies who are less able to accommodate this level of risk • May be difficulties with setting a level of premium that is accurate, cost-reflective and durable in the long term
	FIT with CfD	• High degree of revenue certainty • May be more attractive to a wider range of investors compared to premium FIT • Cost-effective advantages due to the generator 'pay-back' when the reference price is higher than strike price	• Risk of over-supply • Generators are not exposed to long term electricity price risk • Greater complexity compared to other FIT schemes
Supplier obligation		• Simplicity of building on an existing scheme rather than implementing a new approach • Advantages associated with the provision of revenues on top of revenues resulting from the direct sale of electricity largely the same as above	• Complexity may restrict investment to larger generators • Calculating the obligation may lead to excessive (or in some cases insufficient) levels of remuneration • Variability of ROC prices increases revenue uncertainty
RAB model		• Evidence that suggests costs of capital for regulated businesses are lower than unregulated. RAB model could lead to a reduction in cost of capital and hence support costs for RES generators.	• Loss of market efficiency signals because generators are insulated from all risks – better suited to natural monopolies where such incentives do not generally exist. • High risk involved with such radical change to RES regulatory framework

Table 1: Summary of UK Government assessment of low carbon support options in the Electricity Market Reform consultation

The Energy Act 2013 came into effect on 18th December 2013. This Act set out the provisions for implementing the Electricity Market Reform (EMR). This policy initiative was designed to incentivise investment in low-carbon electricity, improve the security of electricity supply and improve affordability for consumers. The Contract for Difference (CfD) renewable support scheme is one of three major policy interventions introduced under the EMR[61].

[61] The other major policy interventions introduced in the EMR were the GB Capacity Market and the carbon price floor.

The European Commission concluded in July 2014 that the UK CfD support scheme is in line with state aid requirements. In the corresponding press release, Commission Vice-President in charge of competition policy Joaquín Almunia said of the scheme, "*It is a fine example of how to promote the decarbonisation of the economy with market-based support mechanisms, at the lowest possible cost for consumers*".

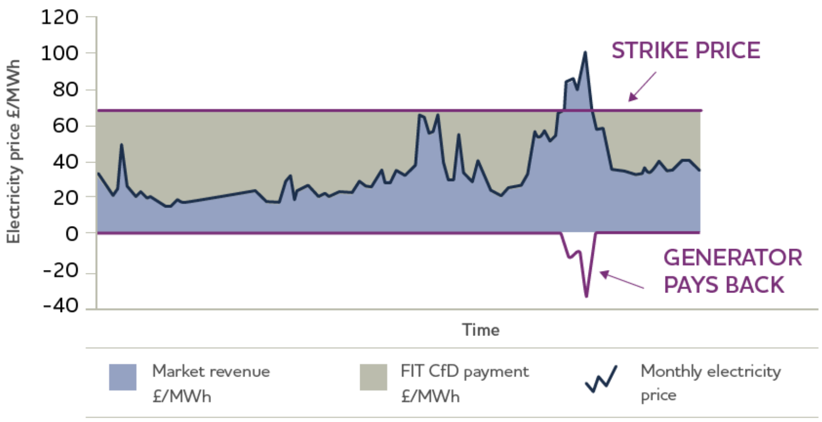
2.1 Key elements of the CfD scheme

The overarching aim of the CfD remains the same as its predecessor – to increase the share of renewables in the UK electricity mix. However, the CfD scheme aims to overcome the limitations of the RO (discussed in section 2) by achieving the following:

- Provide greater revenue certainty to investors of RES generation;
- Reduce the borrowing costs of financing RES generation projects; and
- Encourage competition both within and between generation technologies to deliver cost-efficient RES capacity and improve the affordability of low carbon energy to consumers.

2.2 Basic functionality

As is the case for the German market premium the CfD scheme places an obligation for RES generators to sell electricity. The CfD acts as a contractual agreement between the generator and a Government owned counterparty - the Low Carbon Contracts Company (LCCC). This agreement guarantees that the generator will be paid a set price, 'the strike price', for each unit of electricity produced for the duration of the agreement (15 years). RES generators bid the strike price they are willing to receive for a specified capacity (MW) in a competitive auction. Funding is awarded to RES generators based on these bids, with cheapest strike price bids always accepted first. Once the successful bidders sign their CfD agreement, they have one year to provide evidence of substantial commitment to investment in a project[62], or the contract will be cancelled and the funding recycled (see figure 3).



Source: UK Government White Paper, July 2011, licensed under the Open Government License v1.0

Figure 3: Basic functionality of the CfD scheme

[62] A substantial commitment is defined as a) 10 per cent or more of the estimated Total Project Costs, (as specified by the UK Government); or b) evidence of progress towards timely commissioning, such as evidence of an appropriate construction and supply agreements in respect of the facility.

Once projects are operational, CfD holders have two main sources of revenue from RES generation:

- **Direct revenue from electricity**: In the short term, the generator will gain revenues from electricity sold in the wholesale market; and
- **Compensation from CfD**: Typically, the strike price will be set at a higher price than the average market price for electricity. This 'premium' allows generators to recover the additional costs generally associated with RES technologies. When the strike price is higher than the 'reference price' – a measure of the average electricity price in the GB wholesale market - the generator is compensated the difference.

The example above assumes a strike price of £70/MWh. When the reference market price is below £70/MWh, the generator receives a revenue equal to this deficit. However, when the reference price exceeds the strike price, the generator must pay back this revenue to the CfD counterparty, which is ultimately passed through to consumers in the form of reduced bills. Revenues from the CfD are determined daily on an *ex-post* basis and paid to CfD generators 28 calendar days after the billing period. This will occur every day when the market reference price is below the strike price for that CfD Generator, throughout the 15 year lifetime of the CfD agreement.

2.2.1 Setting the strike price/ competitive auction process

The total amount of financial support available for RES projects is controlled on behalf of consumers by the Levy Control Framework (LCF); this ensures that the cost of RES support to consumers' bills is known. Under the CfD support scheme, two main funding 'Pots'[63] are available[64]; 'Pot 1', which covers established technologies (e.g. onshore wind, solar) and 'Pot 2', which covers less established technologies (e.g. offshore wind, tidal). The strike price is determined by a competitive auction process.

2.2.2 Calculating the reference market price

The reference price is an indexed measure of the average price of electricity. As electricity is traded in different ways and over different periods, the reference price must be carefully calculated to ensure economic signals are accurate and robust. Reference prices under the CfD scheme are differentiated as follows:

- **Intermittent generation:** The intermittent reference price will be the GB day ahead hourly price.
- **Baseload generation:** The baseload reference price will be set on a forward season-ahead basis. The price will be volume weighted and averaged for all days in the season-ahead (Note: season = six months).

[63] The budget changes for each auction and even within a given auction, the pot is different for each delivery year. Total funding for the first auction, under pot 1 was £50m. For pot 2 it was £260m.

[64] A Third 'Pot' also exists for biomass conversion; however, no funding was allocated to this pot. Government may wish to offer funding for such projects in the future.

2.2.3 Treatment of negative spot prices

Under the existing CFD Contract provisions a generator's payments are capped at their strike price (i.e. it will take on the liability below zero). However, in granting State Aid approval for the CfD renewable support scheme, the European Commission later required that:

"By the beginning of 2016, the UK will modify the Contract for Difference to include provision ensuring that generators do not have an incentive to generate electricity under negative prices. If the day-ahead power auction hourly price is below zero, support will be capped at the strike price. Moreover, if prices remain negative throughout a six-hour period or longer then the difference amount under the CFD contract will be set to zero for the entirety of that period."[65]

This requirement has been implemented in a way that applies to all renewable technologies, encompassing both intermittent and baseload generators that sign a CFD Contract from 1 January 2016, but does not apply retrospectively i.e. to CfDs allocated during the first auction.

2.2.4 Balancing responsibilities for RES generators

RES generators under the CfD scheme will be subject to the same standard balancing responsibilities as defined by UK national regulation, i.e. they are responsible for settlement costs associated with deviations from their delivery commitments. It is expected that projected balancing costs will be incorporated into generators' CfD auction bids to ensure an appropriate level of cost recovery is achieved. These balancing costs may be determined by projections of expected balancing costs over the RES generator's lifetime, or may be determined by Power Purchase Agreement (PPA) terms, where balancing and settlement risk is outsourced to a third party.

2.3 Key lessons learnt

The results of the first CfD auction were published in February 2015. However, as of June 2015, none of the successful projects have started generating. Any discussion regarding lessons learnt from this process should be considered purely indicative, with further time needed before any thorough assessment can be conducted.

The inaugural competitive auction process procured 2.1GW of capacity at a total cost of approx. £315m per year. A total of 27 projects were successful; the total capacity (MW) of each successful technology is illustrated below:

[65] http://ec.europa.eu/competition/state_aid/cases/253263/253263_1583351_110_2.pdf, at recital 31.

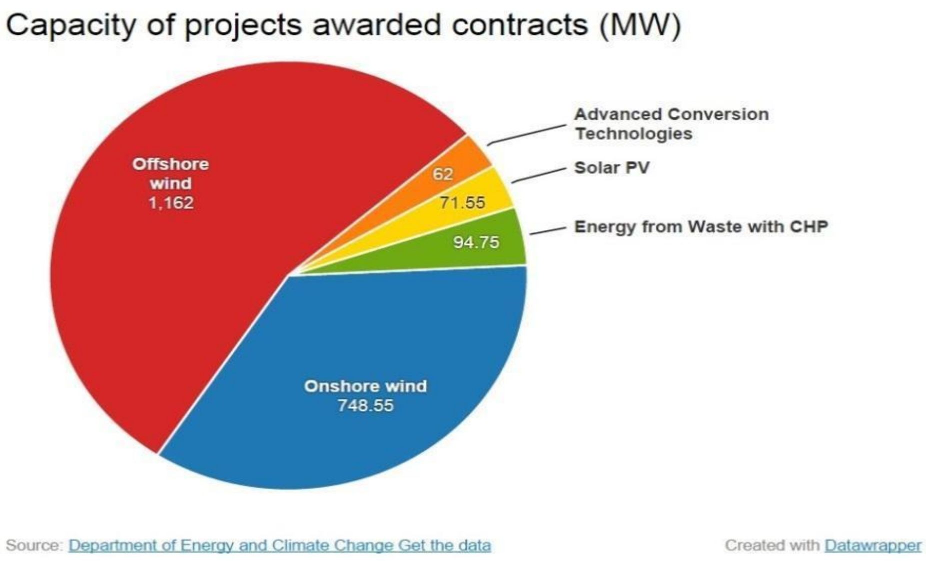


Figure 4: Capacity of projects awarded contracts (MW)

The following indicative lessons learnt can be drawn:

- **Value for money**
  Strike prices established by the first auction cleared at a level significantly lower (on average 17% lower) than the administrative strike price, for almost all RES technologies, in all years. The administrative strike price, set by Government, was determined to be a 'fair' return on investment should the competitive auction not result in a cleared strike price. This provides early evidence that the auction process is delivering better value for consumers, whilst still supporting new RES projects.

- **Transparency**
  For the first time in any GB renewable support mechanism, the CfD auction provided advance prices of RES technologies made available in the public domain. This process has revealed industry determinations of the actual costs of providing RES, for a large number of RES technologies. This level of transparency on the cost of RES generation has been missing from previous schemes, and should help to inform better auction design in the coming years of the CfD scheme.

- **Technology competition**
  Onshore wind dominated the CfDs in the Pot for established technologies, with offshore wind dominating the Pot for less-established technologies. The auctioning process balances the need for cost effective support schemes for RES generation, whilst recognising that less-established technologies will need further support. The domination of wind projects in both pots may mean that other technologies may find it hard to compete for funding through the CfD scheme, leading to a convergence of new capacity to a small number of generation technologies (i.e. the most efficient technologies in each Pot.

There has also yet to be a formal decision making process for RES technologies transitioning from the 'less-established' to 'established' funding Pot. Any decision to 'promote' a technology in this way could likely have considerable impact on the funding received through the auctioning process, and may limit the technology's ability to compete in the established technology funding Pot.

- **Penalties for non-delivery**
  Two solar projects achieved a strike price of £50/MWh in the auction, significantly lower than expected, prompting concerns that some generators may price strategically rather than base their bids on expected costs. Subsequently, both solar projects rescinded their offer and will not develop the projects further. Currently, any successful projects that opt out of their CfD agreement are prevented from participating in future auctions for a period of 13 months.

  The lack of a direct financial penalty for non-delivery in such instances may limit the effectiveness of the scheme, should further cases of 'speculative' bidding occur where there is little intention of delivering on the CfD agreement.

Annex 9 – About CEER

The Council of European Energy Regulators (CEER) is the voice of Europe's national regulators of electricity and gas at EU and international level. CEER's members and observers (from 33 European countries) are the statutory bodies responsible for energy regulation at national level.

One of CEER's key objectives is to facilitate the creation of a single, competitive, efficient and sustainable EU internal energy market that works in the public interest. CEER actively promotes an investment-friendly and harmonised regulatory environment, and consistent application of existing EU legislation. Moreover, CEER champions consumer issues in our belief that a competitive and secure EU single energy market is not a goal in itself, but should deliver benefits for energy consumers.

CEER, based in Brussels, deals with a broad range of energy issues including retail markets and consumers; distribution networks; smart grids; flexibility; sustainability; and international cooperation. European energy regulators are committed to a holistic approach to energy regulation in Europe. Through CEER, NRAs cooperate and develop common position papers, advice and forward-thinking recommendations to improve the electricity and gas markets for the benefit of consumers and businesses.

The work of CEER is structured according to a number of working groups and task forces, composed of staff members of the national energy regulatory authorities, and supported by the CEER Secretariat. This report was prepared by the SDE Task Force of CEER's Electricity Working Group.

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More information at www.ceer.eu.