Revisiting Support Policies for RES-E Adulthood:

Towards Market Compatible Schemes[1]

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Samuel C. Huntington[a]
schuntin@mit.edu

Pablo Rodilla[b]

Carlos Batlle[b]

[a]Corresponding author. MIT Energy Initiative and Engineering Systems Division, Massachusetts Institute of Technology (MIT), 77 Massachusetts Ave., Cambridge, MA 02139, USA.

[b]also with the Institute for Research in Technology (IIT), Comillas Pontifical University, Sta. Cruz de Marcenado 26, Madrid, Spain.

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MIT Energy Initiative, 77 Massachusetts Ave., Cambridge, MA 02139, USA

MIT Energy Initiative

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Abstract

The past two decades of growth in renewable energy sources of electricity (RES-E) have been largely driven by out-of-market support policies designed to drive deployment on the basis of specific subsidies sustained in time to limit investor risk while allowing for larger policy costs. While these policies have proven to be effective, the way they have been designed to date has led to costly market distortions that are becoming more difficult to ignore as penetrations of RES-E reach unprecedented levels.

In the context of this growing concern, this paper provides a critical analysis of the design elements of RES-E support schemes, focusing on how they affect this trade-off between promoting and efficiently integrating RES-E into market environments. The emphasis is on the structure of the incentive payment, which is critical for efficient market integration. We conclude that, while they are still needed, a well-designed capacity-based support mechanism, combined with a set of reference plants, such as the mechanism currently implemented in Spain, is the most robust to future developments in technology cost, performance, and market penetration, and therefore preferable if the goal is truly market integration.

1 INTRODUCTION

Many of the most promising forms of renewable energy sources of electricity (RES-E) have traditionally faced significant barriers to growth, ranging from their high capital cost and perceived riskiness to a market and regulatory structure designed to accommodate conventional fossil-based generators. Policymakers have long recognized that in order to boost their deployment and eventually compete in the energy market, RES-E have needed to be promoted with specific support policies.

Attempts to satisfy multiple objectives with these policies naturally entail tradeoffs in the design of the specific support mechanisms, with perhaps the most significant being the balance between reducing investor risk and increasing market integration. Economic theory dictates that full exposure to market price signals leads to the lowest system cost, but market price risk also increases investor risk perception leading to higher policy support costs.

From the early stages of support mechanisms' implementation, the debate on whether or not to insulate RES-E from market price risk has been intense.[2] In most systems, the inefficiencies derived from reduced wholesale market exposure were assumed to be outweighed by investors' risk reduction. However, as RES-E penetrations have grown so has the maturity of RES-E investors, to the point where they can now reasonably be expected to manage market risks like other conventional generators.

How support mechanisms interfere with market signals

The impacts on the broader power system due to insulating RES-E from market signals are becoming more difficult to ignore. These impacts lead to both short- and long-term distortions. First, some subsidies lead to negative spot prices as RES-E generators with very low variable costs (wind and solar) have an incentive to keep running to access support payments. Indeed, for example, as renewable penetrations have increased across Europe so have the incidences of negative prices. Germany has averaged more than 40 hours of negative prices annually over the past seven years, with slightly lower levels reported in Denmark, Belgium and France. A continuation of current policies is expected to see the number of hours rise to the several hundreds (Höfling et al., 2015). The harmful impact of negative prices due to the

[2]In Europe the debate was around whether to use feed-in tariffs, tradable green certificates or auction-based mechanisms, see for instance Butler & Neuhoff (2008). In the US, the debate continues today, with recent discussions centered around power purchase agreements versus long-term fixed price certificates (Harris, 2015).

influence of RES-E subsidies has been largely documented. For example, Eurelectric (2010) argued that "negative prices indicate two major shortcomings: first, that the necessary price signals to maintain an appropriate balance between supply and demand are missing; second, that there is a lack of grid capacity for transporting the energy generated at low marginal cost to places where it is less efficient (or less profitable due to a different support scheme) to build similar RES plants." Conversely, other voices claim that the efficacy of negative prices depends on perspective: the counterargument, recently raised for example by Höfling et al. (2015), is that the distortionary effects of subsidies for RES-E, including negative prices, are in fact efficient as long as we assume that the subsidy reflects the value of green energy. If we assume that there is additional value in each green MWh that markets do not properly acknowledge, then having RES bidding negative prices could lead to a more efficient long term outcome. However, it is always preferable to correct the roots of the market failure rather than creating new regulatory mechanisms. In this case this implies allocating these support payments in such a way that the short-term efficient dispatch is not distorted and prices do not go below zero, as we later discuss, or directly placing an appropriate value on externalities (e.g. carbon price). For the remainder of this paper we assume the position that RES-support-driven negative prices are undesirable.[3]

In addition to negative price distortions, failure to efficiently integrate RES-E also affects incentives in both the very short-term and the very long-term. Subsidies can, for instance, lead to increased system balancing costs. As part of a balancing mechanism in some countries (e.g., the UK), each power station makes a bid that reflects what they are willing to be paid – or to pay – to be taken off or moved on to the network. When generators face opportunity costs associated with their production they price those costs into their balancing bids, making it more expensive for system operators to take them offline in the course of balancing activities. Finally, subsidies for RES-E can lead to long-term distortions in the composition of the generation fleet. For example, policies that insulate solar from market signals are likely to lead to California's "duck curve" situation where large amounts of fast-ramping dispatchable generation are needed to meet evening demand, potentially leading to a higher cost generation fleet (Denholm et al., 2015). If solar developers faced a more market-compatible incentive, they would be more likely to shift the orientation of panels westward in order to maximize production during high-priced hours, and hence market incomes, rather than simply

[3] In any case, negative prices will gradually disappear. The US PTC applies to the first 10 years of operation, and various feed-in tariffs or feed-in premiums in the EU for as long as 20 years. Once this period is over, variable generators will be fully exposed to market prices, and therefore should be expected to produce only if it is economically efficient from the point of view of the whole system. Furthermore, the learning curves of RES-E, especially wind but also solar PV, are such that these technologies may one day be fully competitive without needing any extra support payments. When any of these two or both situations occur, prices will then be naturally capped at a floor of zero (or close to zero).

maximizing overall production through southward orientation. Greater solar production later in the afternoon would likely lead to a less severe evening ramping period, and therefore a reduced need for highly flexible standby generation.

Future RES-E support schemes need to be market compatible

After more than two decades of worldwide experience supporting RES-E through different types of mechanisms, there is an absolute consensus on the need, and currently the possibility, to further integrate RES-E in markets (Executive Office of the President of the United States, 2016). In its guidelines on state aid for environmental protection and energy, the European Commission (2013) calls for a "minimum level of market responsiveness" in RES-E support mechanisms to enhance market integration and reduce distortions. In the US, the national labs have published several reports on the challenges, barriers and solutions for market integration of variable renewable energy (Bird et al., 2013; Cochran et al., 2014).

Achieving this aim while at the same time balancing investors' risk (allocating no less but no more than the risks that they can properly manage) calls for a careful consideration of the design elements making up RES-E support mechanisms. Different technologies and different investors in different power system contexts face different barriers to becoming competitive; there is no "one-size fits all" support scheme. However, careful consideration of how design elements affect expected outcomes (investor's risk, market compatibility, short and long-term incentives, etc.) can improve the efficacy of support mechanisms in each particular context.

The key to properly analyze RES-E support schemes: focusing on design elements instead of labels

This paper focuses on the design elements of RES-E support schemes instead of resorting to the traditional classification based on labels (e.g. feed-in tariffs, feed-in premiums, auctions, etc.). As renewable energy policies have spread around the globe in the past decades, their designs have been routinely tweaked and adjusted to accommodate local system conditions or policy objectives. As a result, traditional policy labels are no longer applied in a standard or uniform manner, and are commonly subject to misinterpretation. This is becoming an increasingly recognized problem in the literature, see for example (NREL, 2015).

In this sense, there are three major higher level decisions that apply to any type of support mechanism, namely:

- *How to quantify the total support needed by RES-E.* Two major approaches exist in this respect: price-based (administratively determined by the regulator) and quantity-based (determined through market mechanisms, such as auctions). The different properties of price-based and quantity-based mechanisms have been well documented in the literature (see for example Kreycik et al., 2011; Batlle et al., 2012; or Del Río and Linares, 2014). Today, given the relative maturity of different technologies and the fast speed at which learning curves are improving, in some cases approaching the costs of conventional technologies, there is a growing consensus on the suitability of relying on quantity-based mechanisms (Maurer and Barroso, 2011), as they take advantage of competitive pressure between developers to determine the "correct" incentive. In this way they obtain the lowest possible price for support for renewable electricity projects.[4]
- *The technical and operational integration of the technology.* This refers to whether or not the technical characteristics and operational requirement rules are in line with other generators. For example, whether plants have to provide reactive power, or whether their physical dispatch has to be declared before the last market gate closure with subsequent balancing responsibility. Each jurisdiction has a grid code (i.e., a set of rules and procedures) that details specific technical and operational requirements for generators connected to the grid. Regarding technical requirements, RES-E have traditionally been exempt from many of the obligations placed on other power plants in order to facilitate their interconnection. Instead, there are typically specific technical requirements for RES-E technologies; as pointed out by IEA-RETD (2015), these requirements may include: (i) fault ride through requirements (procedures for responding to system disturbances), (ii) frequency control and (iii) reactive control. The most reasonable approach on this subject is to ensure that RES-E are initially built with as much grid support functionality as projects can cost effectively handle. This requires the System Operator to carry out detailed cost-benefit analyses, which must be continuously updated as technologies develop.
- *The structure of the perceived remuneration.* By "perceived remuneration" we mean the incentive that renewable plant operators and investors expect to receive given that the actual remuneration may vary depending on the size, type, and operating characteristics of the plant itself, or on exogenous market factors. This paper focuses precisely on the design elements associated to this issue, where there are many design

[4] However, quantity-based mechanism involve higher entry cost for small investors (domestic customers, farmers, etc.) in small scale projects. When this is the case the solution can be applying different types of mechanisms to different sizes of projects or classes of technology (NREL, 2015). For example, price-based mechanisms might be preferred for small scale projects, while quantity-based mechanisms are better suited for larger projects.

alternatives and the implications for outcomes including investor confidence, policy costs, and market impacts are particularly nuanced.

At the most fundamental level, support schemes remuneration can be structured either to provide compensation based on actual output or on some measure of installed capacity. In their purest form, these two approaches contrast both in terms of the incentives they create for project quality and the way they balance revenue security versus exposure to market signals. The remainder of this paper aims at identifying and analyzing the most relevant design elements of these two RES-E support remuneration schemes. First in Section 2, we discuss design elements of production-based support mechanism. In Section 3, we analyze capacity-based support mechanisms. The objective in both sections is to focus on the market compatibility of different design alternatives for each approach. Section 4 concludes with the major highlights and recommendations.

2 PRODUCTION-BASED MECHANISMS

Production-based remuneration schemes are characterized by periodic payments based on a generator's actual production and, in some cases, also based on market prices. By tying payment to the energy sold these schemes naturally create an incentive to maximize energy production. In the case of RES-E, this means developers naturally optimize their investment decisions, preferring (as long as it is economical) the windiest/sunniest locations, the most efficient components, and the best system designs. However, as pointed out in the introduction, projects with the highest capacity factors do not entail the highest value of the energy produced (e.g. there might be projects with lower capacity factors but whose production is more correlated with the system needs).

With this type of mechanisms, the incentives in the short- to medium-term operating behavior are, as well-known, distorted. While the operating decisions of wind and solar are simplified compared to their thermal counterparts due to their non-dispatchability, decisions such as shutting down in the presence of negative prices, or scheduling maintenance during off-peak times, should still be dictated by price signals coming from wholesale energy markets. But if not properly designed, linking support payments to production adds a second signal which can cause generators to change their behavior, resulting in distortive impacts across the broader market.

Production-based support mechanisms are characterized by three key design features: i) the quantity of production supported, ii) the type of scheme used to deliver payment, and more recently there is also concern on iii) the treatment of remuneration conditions during hours of negative prices (or more generally, during hours with prices below the marginal cost). We analyze these design features next.

2.1 DESIGN FEATURE 1: AMOUNT OF PRODUCTION ENJOYING SUPPORT

The first key decision in the design of production-based schemes is the quantity of generation production to support. Regulators can essentially decide to either remunerate any and all output or provide support only up to a certain limit. This limit can be established on a settlement period basis (e.g. hour) or in terms of the total annual production entitled to receive the support.

- An example of the first type of limit would be to restrict to 70% of the installed capacity the hourly amount of energy entitled to receive a premium. This limit, not implemented in practice to the best of the authors' knowledge, would reduce the amount generators' are willing to bid below marginal costs.

- An example of the second limit, would be to restrict support payments to a benchmark number of hours (e.g. 1700 a year) after which any production only receives the market price. This approach, which can be found in practice in some systems (e.g. a previous support scheme in Spain introduced such a limit), has the effect of limiting windfall payments to developers in resource-rich areas, while still creating incentives to site projects in the best locations. Again, limiting the quantity of energy reduces the amount of energy bid by the generator below the marginal cost.

Most current support schemes do not attach payment to a specific quantity of energy and instead simply cover any and all production. Examples include the UK's Contracts for Differences scheme, the Production Tax Credit in the US, and sliding market premiums in Germany.

DESIGN FEATURE 2: TYPE OF SUPPORT FOR PRODUCTION THAT IS COVERED

Once quantity is established, the next key decision to be made is the type of production support. Though there are many variations, they can generally be classified based on how the total remuneration is determined, namely whether it is i) the remuneration is not tied to any market, ii) the remuneration is tied to the energy market, or iii) tied to a separate market.

2.2.1 Production-based support not tied to any market

Once the incentive level is established, qualifying RES-E generators are paid on a per-kilowatt-hour basis for any production regardless of the demand for or price of electricity at that time. The so-called "feed-in tariffs" are the prime example of this type of flat, out-of-market approach. They have been historically popular because they create an environment of high investor confidence due to the elimination of market price risk.[5] However, they are also notable for introducing the highest possible market distortions as generators are completely insulated from market signals and retain an incentive to produce even when they are causing very costly thermal dispatches. The larger the amount of conventional inflexible generation, the more acute this issue may become. When these costly thermal dispatches can be avoided, either through higher demand consumption or lower RES-E production, market prices may become negative. The problem is exacerbated by the "priority dispatch" rule which reinforces RES-E by obliging grid operators to accept RES-E generation ahead of other sources, effectively making it inflexible.

This priority dispatch rule (which could have been denoted as "obligation of dispatch" since RES-E generators would be indifferent to produce as soon as they would receive the premium) was included in the EU legislation – the Renewables Directive 2001/776 – to promote the development of RES-E. It established that "Member States shall ensure that when dispatching electricity generating installations, system operators shall give priority to generating installations using renewable energy sources in so far as the secure operation of the national electricity system permits and based on transparent and non-discriminatory criteria."[6] The practical effect of this rule was that production with renewables could only be limited because of security reasons. But this rule made only some sense (if any) since feed-in tariffs were purely production based, meaning RES-E plants already had the incentive to produce whenever feasible to maximize access to subsidies.

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[5] Note that contrary to widespread perception, other types of risk, such as regulatory risk, remain. See for example the case of Spain and the Czech Republic where the value of feed-in tariffs were reduced retroactively.

2.2.2 Production-based support tied to the energy market

There are two types of support mechanisms tied to the energy market. They both require generators to sell their production in the wholesale market and then provide a compensation based on the market price. In the first type of mechanism a positive (or null) premium is provided on top of the market price. When these premiums are strictly positive or null (depending on the price), these schemes are broadly classified with the label of feed-in premiums.

These schemes are market-integrated by nature as generators are required to sell their power in the wholesale market, taking into account their own generation profile as well as future development of supply-demand dynamics. However this does not eliminate the potential for market distortions as the premium still induces RES-E generators to continue producing even when market prices fall below their marginal cost, thus driving prices further negative and distorting the price signal for other market participants. The extent of these distortions depends critically on how the premium is calculated, and whether it is fixed or "sliding".

- Fixed premiums are defined ex-ante and do not vary, acting as a set adder on top of the market price. They expose generators to the same level of market volatility as any other market participant, but allow for the recovery of (the supposedly larger) capital costs (and reduce revenue uncertainty) by increasing overall market revenues relative to the absence of a premium. The production tax credit in the US, the "green bonus" in the Czech Republic[7] and a similar scheme in Slovenia are all good examples of fixed premiums (Held et al. 2014).

- Sliding premiums are calculated ex-post as the difference between a strike price, which reflects the long-term price needed to recover fixed costs, and a reference price, which reflects in some way the expected revenues earned in the energy market. By continually correcting total payment (market revenue + premium) to a fixed strike price, a sliding premium provides a high level of revenue certainty while still exposing producers to market prices in real time.

[6] Note that an additional motivation behind this rule was to incentivize EU Member States to design support mechanisms to ensure they reached their national targets for raising the share of renewables in their energy consumption by 2020, under the Renewable Energy Directive (The European Parliament and the Council of the European Union, 2009).

[7] The "green bonus" in the Czech Republic is an alternative option to a standard feed-in tariff. Eligible RES-E generators sell their electricity directly in the wholesale market and then, in addition to standard market revenues, receive a fixed payment for each kilowatt hour of energy sold.

The duration of the settlement period for calculating the reference price is a critical factor in this equation which conditions the behavior of generators. If, for instance, this period is an hour (the premium is calculated every hour taking into account the market price) then generators are continually "topped up" to the strike price and are thus well-insulated from market volatility (see the right-hand image in Figure 1). The signals received by generators are equivalent to a flat feed-in tariff; regardless of when they produce, and of the market price at that time, their revenue (i.e., market price plus premium) is always reset to a target level (the strike price). At the other extreme, if the reference price is based on a long-term average (yearly), the premium is more stable on an hour-by-hour basis; the mechanism sends signals equivalent to a fixed premium, exposing generators to market volatility and price risk. In practice many countries choose a middle ground, balancing revenue certainty with market exposure. Germany for example calculates reference prices based on a monthly average, while Finland uses a three-month average.

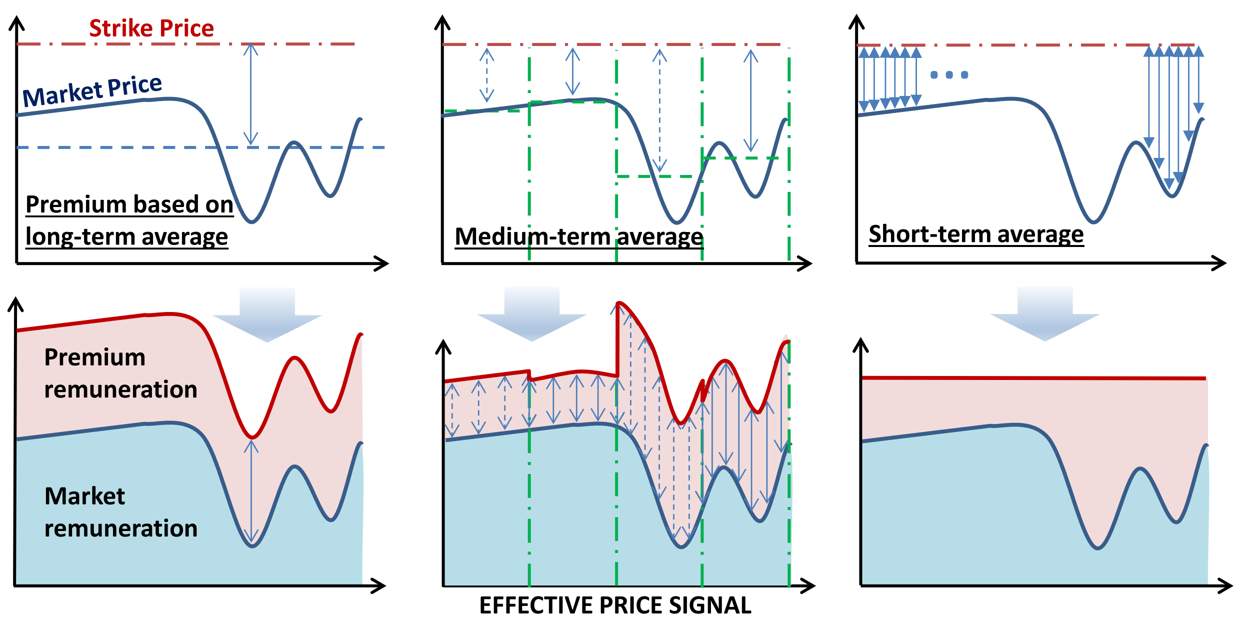

Figure 1: Reference price settlement periods

Whether the premium is fixed or sliding though does not preclude negative pricing distortions. Generators always retain an incentive to produce until the market price reaches the negative of the premium (sliding premiums are generally capped at the strike price lest generators retain an incentive to produce until prices reach negative infinity).

Attaching the premium to a specific quantity of energy introduces uncertainty into the generator's decision-making, which can help mitigate, though not solve, the issue. For example, if prices are negative but a generator expects to be able to fill its production contract in later positive-priced hours, the generator may self-curtail so as to preserve access to its maximum premium (rather than the premium minus the payment to continue production). However, this only works when the generator can count on production at a later date – an expectation that diminishes toward the end of the contract.

Finally, the sliding premium may be allowed to go negative, as in the case of the UK's Contracts for Differences. Under this arrangement generators still receive a variable premium calculated as the difference between the reference price and the strike price, but are also forced to pay back the difference when the reference price exceeds the strike price (peak days). RES-E generators still retain an incentive to produce whenever prices are above their variable cost (zero), but their revenue is effectively capped at the strike price. This feature helps control policy costs while still creating a high level of revenue security.

2.2.3 Production-based support tied to certificates (or obligations)

A third alternative for production-based schemes consists of tying premiums to an entirely separate market where the value of renewable generation is determined by the demand for it. These mechanisms are broadly categorized as "quota obligations" or "tradeable green certificates" or "renewable portfolio standards" because energy suppliers are required to purchase a given amount of clean energy which is tracked through certificates handed out for renewable production. While quota schemes expose producers to the efficiency of market prices, they provide less revenue certainty for investors which can raise the cost of capital and thus the cost of RES-E in general. Price floors are commonly introduced to reduce revenue uncertainty, but by guaranteeing a minimum value for the premium quota schemes are prone to the same market distortions as traditional feed-in premiums. Even a well-functioning certificate market is not immune to these problems. In a market with relatively stable prices (e.g., Sweden) generators may still find it in their interest to produce when prices are zero or slightly negative, knowing that they can still sell their production in the certificate market for a profit.

2.2.4 Treatment of premium during hours of negative prices

Countries supporting RES-E development through production-based schemes take a variety of approaches to remuneration during hours of negative prices. The primary approaches are summarized here, though in practice many countries employ a combination of these design features:

- *Prohibit negative bidding.* Several countries, including Spain, Portugal, and Italy, have elected to ban negative prices outright. This policy simply removes the mechanism by which inflexible generators signal to RES-E to curtail, leading baseload generators to reduce their output, or, if security is threatened, leading the system operator to curtail RES-E. This exposes RES-E generators to higher revenue risk leading to higher strike prices.

- *Pay on availability when prices fall below zero.* Under this proposal, when prices on the reference market go negative, the system operator switches from paying based on output to paying based either on the capacity of the plant (e.g., a percentage of rated capacity) or on some measure of demonstrated availability. The total capacity, or 'firm volume', that the payment applies to must be established up front so that appropriate payments can be calculated and anticipated. A version of this approach was proposed in the UK but ultimately rejected amid concerns by the system operator that it would lead to a 'cliff-edge' effect where generators were highly sensitive to small changes in market prices: plants could suddenly switch between a desire to run at full output and access premium payments when prices are above zero, or turn off and be paid on availability when prices are below zero. Spain does not permit negative prices, but instead curtails wind plants during periods of over-generation and makes availability payments equivalent to 15% of the wholesale price.

- *Ban negative bidding during consecutive hours.* Germany and the UK currently have policies that withhold market premiums for RES-E generators after 6 consecutive hours of negative prices on the wholesale market. Extended periods of negative pricing are more likely to be caused by RES-E generators seeking to maintain access to support payments than, for example, thermal generators accepting negative prices so as to offer their power in balancing markets. The intent of this solution is therefore to give the market some leeway to resolve issues itself through prices, while also limiting the revenue loss to inflexible thermal generators during high RES-E production.

- *Permit negative prices but cap support payments.* This solution is critical in markets where RES-E premiums are calculated as the difference between the market price and a strike price. In the absence of caps, the premium would get larger the more negative the market price fell, increasing policy costs while removing the incentive for RES-E generators to ever accept the bid and self-curtail. Capping the support payment (typically at the strike price, as is done in the UK and Germany), means the revenues earned by supported generators gradually falls until the absolute value of the market price is equal to the premium cap.

- *Permit negative prices but institute a negative price floor.* Capping negative prices at a minimum level may be desirable to limit revenue loss to inflexible generators. However, price floors should be lower than the absolute value of the RES-E premium otherwise RES-E plants will never find it in their interest to accept negative bids and self-curtail (Wolak, 2012). This is similar to the solution reached in many corporate power purchase agreements where generation during hours of negative prices harms the buyer but not the seller, who benefits from access to subsidies. Many PPAs include clauses allowing the RES-E generator to continue generating until prices fall below the negative of the support payment, creating an artificial price floor.

2.3 CONCLUDING ASSESSMENT ON MARKET COMPATIBILITY

The variety of design alternatives for production-based schemes illustrates the lengths to which policymakers will go to reconcile conflicting policy objectives, namely revenue certainty and integration in energy markets.

But the tradeoff between these objectives is difficult to avoid. Fixed premiums expose generators to efficient market signals, but still introduce, albeit limited, distortions, and come with the price of reduced revenue certainty for project developers. Sliding premium schemes attempt to provide greater revenue certainty but create the potential for larger negative price distortions as generators are incentivized to bid up to the negative of the strike price (generally much higher than a fixed premium). Certificate schemes are often perceived as the most “market compatible” since market signals and premium determination are fully decoupled, but the risk introduced by the certificate market can make financing costs unacceptably high. Measures to reduce that risk, such as price floors, simply transform the scheme to one that functions like a traditional fixed premium.

It should also be noted that production-based schemes typically create incentives to maximize total energy generation, and not necessarily price- or system-value-oriented generation. Solar and wind developers are able to take decisions at the time of investment that influence the degree of alignment between production and demand profiles, but have no incentive to do so as long as the emphasis is purely on total generation. Schemes that insulate investors from market volatility (e.g., feed-in tariffs, sliding premiums) exacerbate this problem.

In the figures below, this effect is quantitatively illustrated. Figure 2 illustrates the simulated energy output of one kilowatt of solar PV capacity in Los Angeles (CA) depending on orientation and tilt (EIA, 2014) and the hourly prices in Caiso, simulated with the model used in Chapter 8 of the MIT Future of Solar Energy study (MIT, 2015). In Figure 3, the hourly market incomes with and without a $20/MWh premium are illustrated. The table in this graph includes the daily income for these two cases for each orientation. As it can be observed, the energy-based subsidy leads to a less efficient tilt as income is larger for the panel tilted towards the South.

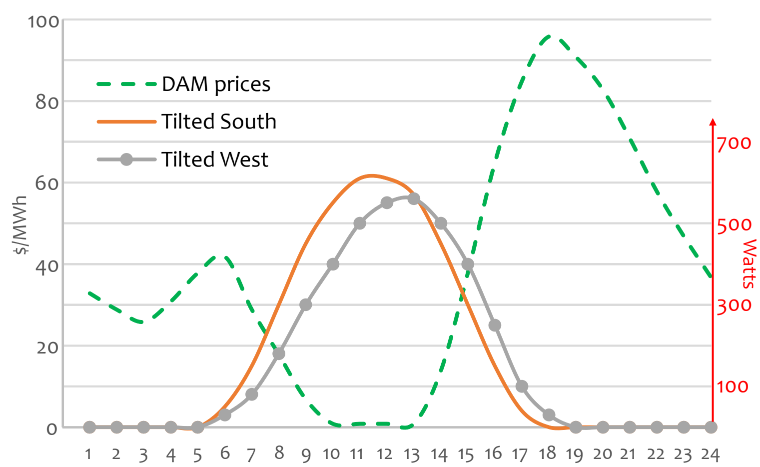

Figure 2. Day-ahead market prices versus panel orientation

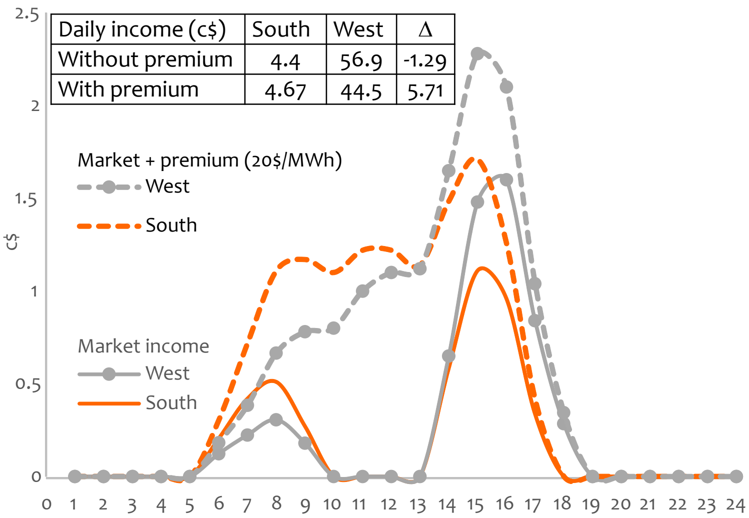

Figure 3. Market and premium income for solar production for different panel orientations

Production-based schemes always suffer from this fundamental tension between creating revenue certainty and incentives for high-quality projects on one hand, and limiting distortions on the other. One way or another, paying for production alters the price signals from the energy market, leading to changes in generators' operating behavior which has a negative impact on the economic efficiency of the system as a whole.

3 CAPACITY-BASED MECHANISMS

Capacity- or investment-based subsidies are intended to cover the difference between a plant's upfront investment cost and any market revenues such that the project is likely to be profitable and therefore attractive to investors. While the choice of paying on the basis of the installed capacity or project cost has important consequences depending on the policy goals, the two methods are similar in that they both provide support upfront based on expected performance rather than actual generation. Capacity-based mechanisms are characterized by several key design features that affect the potential outcome, including i) the methodology to estimate RES-E market-based revenues to be complemented, ii) the frequency (upfront vs periodic) and updating of the payment (constant vs updated), and iii) performance specifications.

3.1 DESIGN FEATURE 1: ESTIMATING THE MARKET-BASED REVENUES TO BE COMPLEMENTED

The first challenge consists of determining the size of the support payment needed, calculated as the difference between the total costs to be recovered and the market revenues:

- *Total costs to be recovered:* the sum of investment costs and total lifetime variable costs (O&M, fuel, etc.) plus a rate of return high enough to attract the desired level of investment. This corresponds to the strike price which can be determined through competitive auction.

- *Market revenues:* the revenues earned by plant operators from directly marketing their electricity in wholesale power markets. These can be estimated from price and production forecasts, based on reference facilities, or could correspond to the revenues of an actual plant.

A key relevant design decision in this framework is how to estimate the RES-E plant market-based income: i.e. how much a project will earn by operating in the various segments of the market (potentially including the various energy markets, capacity payments, and other services).

- *Forecasting:* The most straightforward approach is to develop an ex-ante forecast of market prices from which regulators can estimate future market revenues for a given RES-E plant over the course of its life. Forecasting electricity prices in the long term is, however, notoriously error-prone, which creates a risk of over- or under-investment. If market revenues turn out to be higher than the forecast, RES-E developers reap windfall profits and regulators are left to rue a missed opportunity to use limited funding resources. If market revenues turn out lower than the forecast, RES-E projects are unable to recover their costs, raising the risk premium on future projects.

- *Reference Plants:* A more sophisticated way to estimate market-based revenues is by defining a reference plant which reflects the business activity that would be carried out by an efficient and well-managed company. This reference plant can either be synthetic (in which case the transparency in the definition is key to providing a stable framework) or real (based on an individual installed plant or on the combination of several real plants). This approach based on reference plants has been adopted in the latest mechanisms implemented in Spain, see Barquín (2014).

  Reference plants can be technology-based (if different incentives are to be provided to the alternative technologies) or exclusively based on the most competitive RES-E technology (if the objective is only to maximize renewable production in the short to medium term).

  Designing or designating reference plants involves estimating the production hours and the participation of the plant in different market segments. In order to have a realistic representation of agents' behavior, a reference plant based on real plants may be a preferable design choice (either by means of an average or a percentile representing best practices). Using real plants creates yardstick competitive pressure for RES-E to outperform their competitors; plants with above average market revenues receive the same support payment, and thereby earn higher returns overall.

  The reference plant needs to be updated for new projects so as to adapt to evolving conditions in the plant's production potential (for example, because of variations in the available primary energy resources of new projects or due to technological efficiency developments). For example, not updating the wind reference plant for new wind investments might result in an incentive reduction as windy locations tend to be filled up. Once the sites which outperformed the reference plant are filled up, investment would drop off dramatically as it would be difficult for developers to "beat" the reference plant and earn enough profit to attract investors. The challenge is to find the right balance between the number of benchmarks needed and the transparency and manageability of the mechanism. As a way of example, in the Spanish case, more than twelve hundred reference plants have been defined, diversified by technology, size, location, and construction date (Barquín, 2014).

3.2 DESIGN FEATURE 2: TIMING, FREQUENCY AND UPDATE OF SUPPORT PAYMENT

The support payment can either be settled ex-ante or ex-post. When determined ex-post, it is based on actual observed revenues of the reference plant from the market. For example, if energy market prices turned out to be lower than expected, an ex-post capacity incentive could be adjusted up to ensure RES-E plants are able to recover their fixed costs. This is similar in theory to how Ireland adjusts the payments provided by its capacity market based on the previous month's loss of load probability (Lawlor, 2012).

Providing support up front has the advantage of lowering the administrative burden (it requires only a single transaction) and reducing financing costs as banks are more willing to lend to projects that have already secured a subsidy. On the other hand, calculating the incentive ex-post makes it easier to guarantee a certain level of cost recovery, regardless of external factors such as market prices or plant location.

As regards the frequency of the payment, capacity-based support can be delivered either as a one-time lump-sum payment or through a series of periodic payments over time. One-time payments are advantageous in that they can be concluded in a single transaction, reducing the administrative burden on both the project developer and the government counterparty. On the other hand, periodic payments are more flexible as total compensation can be adjusted over time. This can be useful for controlling policy costs and limiting windfall profits, or conversely, for keeping an underperforming project profitable. Again, it is a balance between allocating risks between the counterparties, with the investors on one side, and the regulator (on behalf of consumers or taxpayers) on the other.

Germany uses periodic payments to support wind generators, adjusted after several years depending on the performance of the project relative to a reference facility (Purkus et al., 2015). This has the effect of adapting support costs to revenue requirements depending on the project location: the projects in the best (windiest) locations have their incentive reduced since they are earning above average market revenues, while projects in sub-optimal locations receive a premium incentive to ensure they are able to recover their investment costs. While this option deviates from strict economic efficiency, some policymakers may find it desirable as a means of promoting RES-E development in diverse locations on the basis of social externalities.

3.3 DESIGN FEATURE 3: PERFORMANCE SPECIFICATIONS

One of the consistent criticisms of capacity-based mechanisms is that they may not motivate effective design, efficient component selection (high efficiency panels/turbine blades), or proper maintenance once the project is operational (Hoff, 2006).

The effectiveness of the capacity-based incentive depends on the weight of three variables: i) the market-based incentives, ii) the total support provided and iii) the price of the inefficient lowest-cost alternatives that are eligible to receive the support. If there are low-cost alternatives that can recover the investment through the support provided, then clearly additional rules will be necessary to achieve an efficient result.[8] In parallel, the higher the weight of market remuneration, the higher the incentive not to install inefficient alternatives.

The risks described above can be mitigated by attaching **minimum performance requirements** to the incentive, and then adjusting or even withholding part of the payment subject to conditions. Again, Spain's support scheme, for example, defines minimum operating hours by technology and adjusts the remuneration payment depending on performance relative to that benchmark. Generators receive the full remuneration when the benchmark is exceeded, and are at risk of losing up to all of their support if actual performance is significantly below the benchmark. These tactics require on-going performance monitoring which increases administrative cost, but the upside can be substantial in terms of higher and longer lived production from quality systems.

In addition to performance monitoring, or perhaps as an alternative, regulators can impose minimum standards for component efficiency or system design. It can be challenging however for regulators to maintain reasonable standards in light of rapidly evolving technology. Furthermore, there is a risk of regulatory overreach as innovative technologies (thin film solar) and design approaches (new racking designs for solar arrays) may be restricted in their development if they do not meet the administratively determined criteria.

[8] For example, inexpensive solar panels with low conversion efficiency will have an easier time recovering their fixed costs (and therefore will be preferable to investors) if the investment discount relative to the high-efficiency panel is greater than the lost revenues associated with poor conversion efficiency, again, relative to the high-efficiency option. In other words, in the case of solar, the panel with the lowest (pre-incentive) cost per expected-lifetime-kWh ratio will be the most attractive. This would not necessarily be the case in production-based schemes where generation is effectively more valuable due to the subsidy and a high-efficiency panel that increases production may therefore be worth a premium.

3.4 CONCLUDING ASSESSMENT ON MARKET COMPATIBILITY

In general, capacity-based support mechanisms are the most compatible option with a market-oriented power generation sector. They avoid the market distortions introduced by production-based schemes by decoupling payment and performance, and therefore avoid interfering with short term market signals. They also come with their own set of well-known risks incentives flowing to low-quality projects, and inflexibility to evolving market conditions (i.e. the risk of windfall profits, or conversely, the risk of underfunding if market revenues deviate significantly from expectations).

Many, though not all, of these risks can be mitigated through incorporation of specific design features. The risk of under or over-paying can be reduced by using reference plants, diversified based on key performance criteria such as plant location and size, though at the cost of reducing the incentive to develop the best sites first (i.e., second-best locations could be just as profitable as first-best). The risk of payments flowing to poor performing projects can be reduced by attaching minimum performance requirements. Finally, paying out the incentive over time rather than in a single lump sum leaves room for program administrators to adjust the level of payment in response to changing market conditions.

4 CONCLUSIONS AND POLICY RECOMMENDATIONS

This paper provides a review of critical design elements for regulators seeking to promote renewable energy sources of electricity (RES-E). Where similar reviews focus on the effectiveness or efficiency of different support mechanism archetypes (i.e. feed-in tariffs, renewable portfolio standards, etc.), which can refer to a broad range of design alternatives, here we focus on the structure of the support payment and its core design features in relation to market compatibility.

Increased penetrations of RES-E over the past decade have been accompanied by the increased maturity of its investors. The notion that RES-E should be insulated from the risks and competitive pressure of the wholesale market is increasingly tenuous, especially in light of the inefficiencies introduced by special treatment. This has led to a growing consensus that RES-E should participate in wholesale markets with the same responsibilities and risks as conventional generators, and any associated support policies should be fully market compatible.

To this end, in cases where the regulatory decision is to explicitly support any RES-E technology, we advocate in favor of **capacity-based support payments that make use of reference facilities** to estimate market revenues. The scheme would function as follows: any new plant coming into operation would be assigned by regulators to a particular reference facility that corresponds to the same technology type (wind, solar, etc.), similar commissioning date, and similar project size. The investment cost of the reference facility is known and the market revenues and operating costs (only applicable to fuel-based renewables like biomass) are monitored on an ongoing basis. Support payments would then be calculated as the difference between the reference facility's market revenues and the annuity of its investment cost, plus an adder to ensure a reasonable rate of return.

Ideally reference plants should be based on actual generators (e.g., the median 10% by market revenue or investment cost to better reflect actual bidding behavior). Payments should be delivered periodically over time so that remuneration can be conditioned on meeting minimum performance requirements. Each reference facility should have different performance requirements that reflect the typical conditions encountered by that type of facility.[9]

Finally, auctions should be used in the procurement process to secure the most competitive projects. Once contracts are awarded and reference facilities assigned, the reference investment cost should remain fixed over the duration of the contract to provide investors with greater revenue security. The use of regular auctions will result in updated reference investment costs that reflect changes in technology cost and performance, market conditions, and access to resource-rich locations (the best sites should gradually fill up).

The capacity-based support scheme outlined above has several notable features. First, it is highly compatible with competitive electricity markets compared with a production-based scheme because it severs the link between production and payment; only market signals are left to dictate generator operating decisions. This compatibility relates not only to short-term energy markets but also to capacity reliability mechanisms, with which RES-E support should soon converge as the learning curves of RES-E technologies are approaching (in some cases surpassing) conventional generation technologies (Mastropietro et al., 2014). Second, it guards against the traditional risks of capacity-based schemes through a combination of performance requirements and natural incentives: generators can

[9] As noted earlier, in the absence of production-based remuneration, performance requirements are a critical design element to ensure support payments do not flow to low quality projects. It is worth noting that the risk of funding poor projects diminishes as investment costs fall and market revenues make up an increasing portion of cost recovery – that is, the incentive to build low-cost/low-quality projects simply to access lucrative support payments naturally falls as technologies mature because support payments shrink relative to market revenues.

make more profit by beating the reference facility (e.g., superior bidding strategy, better forecasting/fewer imbalances, superior location for wind/solar resources, etc.), creating a natural competitive pressure to optimize production and siting decisions. Third, by making use of auctions it introduces competition into the procurement process as well, ensuring that investment costs are not inflated in an attempt to secure larger support payments.

Finally, it is also noteworthy that the scheme is fairly complex (especially compared with the simple feed-in tariffs that have dominated global support schemes for decades). Developing accurate reference facilities is a significant administrative burden for the regulator or policymaker, especially if they are attempting to promote different technologies of different sizes and updating them regularly. But this highlights an important point: delivering subsidies effectively is challenging. Simple and straightforward support payments too often lead to market distortions and inefficient outcomes – the support schemes of the future will necessarily have to be more sophisticated to spur investment without obscuring the benefits of competitive market forces.

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