UNIVERSITY OF CAMBRIDGE | Energy Policy Research Group

Capacity vs Energy Subsidies for Renewables: Benefits and Costs for the 2030 EU Power Market

EPRG Working Paper 1911

Cambridge Working Paper in Economics 1927

Özge Özdemir, Benjamin F. Hobbs, Marit van Hout, and Paul Koutstaal

Abstract: Policy makers across Europe have implemented renewable support policies with several policy objectives in mind. Among these are achieving ambitious renewable energy targets at the lowest cost and promoting technology improvement through learning-by-doing. Although subsidy mechanisms based on energy out-put are cost-effective for achieving a certain renewable energy target in the short run, policies tied to capacity installation might be more effective in reducing technology costs in the longer term. We address the question of how policies that subsidize renewable energy (feed-in premia and renewable portfolio standards (RPSs)) versus capacity (investment subsidies) impact the mix of renewable investments, elec-tricity costs, renewable share, the amount of subsidies, and consumer prices in the EU electric power market in 2030. Our analysis is unique in its focus on the market impacts of capacity-oriented vs energy-oriented policies while considering a realistic landscape of diverse and time-varying loads and renewable resources (including existing and potential hydro, wind, and solar resources), as well as fossil-fueled generators and network constraints.

Keywords: Electricity markets, renewable policy, capacity subsidy, energy subsidy, renewable target

JEL Classification: H23 (renewable subsidies), L94 (electricity industry), Q28 (renewables policy), Q48 (energy policy)

Contact Ozge.Ozdemir@pbl.nl
Publication March 2019
Financial Support Energie Onderzoek Nederland (ECN), Netherlands Environmental Assessment Agency (PBL), US National Science Foundation grant 1408366

Capacity vs Energy Subsidies for Renewables: Benefits and Costs for the 2030 EU Power Market

Özge Özdemir[a,*], Benjamin F. Hobbs[b], Marit van Hout[a], and Paul Koutstaal[a]

[a] PBL Netherlands Environmental Assessment Agency, Bezuidenhoutseweg 30, 2594 AV Den Haag, The Netherlands

[b] The Johns Hopkins University, Baltimore, MD 21218 USA

ABSTRACT

Policy makers across Europe have implemented renewable support policies with several policy objectives in mind. Among these are achieving ambitious renewable energy targets at the lowest cost and promoting technology improvement through learning-by-doing. Although subsidy mechanisms based on energy output are cost-effective for achieving a certain renewable energy target in the short run, policies tied to capacity installation might be more effective in reducing technology costs in the longer term. We address the question of how policies that subsidize renewable energy (feed-in premia and renewable portfolio standards (RPSs)) versus capacity (investment subsidies) impact the mix of renewable investments, electricity costs, renewable share, the amount of subsidies, and consumer prices in the EU electric power market in 2030. Our analysis is unique in its focus on the market impacts of capacity-oriented vs energy-oriented policies while considering a realistic landscape of diverse and time-varying loads and renewable resources (including existing and potential hydro, wind, and solar resources), as well as fossil-fueled generators and network constraints.

1. Introduction

It is widely agreed that renewable electricity policies, such as feed-in tariffs, that encourage selection of the type and location of renewable development irrespective of the marginal value of its output will promote inefficient investment (Huntington et al., 2017; Neuhoff et al., 2017). Such policies tend to value maximization of renewable production without considering the economic value of the energy they produce for meeting power demands or emissions goals. Therefore, the EU and its member states are moving towards feed-in premiums, curtailment requirements, and other policies that are intended to align renewable investment profitability with the market value of electric energy. Development may therefore be encouraged at locations where resources produce fewer annual MWh, but where the increased energy market value more than makes up for decreased production, due to timing or transmission availability. This supports the objective of minimizing the net economic cost of achieving renewable energy targets, at least in the short-term.

☆Funding was provided by the Government of the Netherlands while the first, third, and fourth authors were at Energieonderzoek Centrum Nederland (ECN), Petten, NL. Funding for the second author provided by ECN and the US National Science Foundation under grant 1408366. We thank our ECN colleagues for many helpful conversations on EU renewables policy, especially Adriaan van der Welle, Karina Veum, Luuk Beurskens, Ayla Uslu, Francesco dalla Longa, Jaap Jansen, and Jos Sijm, as well as Gerard Doorman (SINTEF), Nils May (DIW), and Martin Greiner and Bo Tranberg (Aarhuss University) for data and discussions. All opinions and errors are the responsibility of the authors.

*Corresponding author.
Email addresses: ozge.ozdemir@pbl.nl , bhobbs@jhu.edu, marit.vanhout@pbl.nl, paul.koutstaal@pbl.nl

A longer term objective is to reduce renewable energy costs through learning-by-doing. Learning externalities are widely recognized as a benefit of renewables promotion (NAS, 2017; Newbery, 2018), although estimates of the magnitude of learning differ among studies even of the same technology (Nagy et al., 2012; Rubin et al., 2015). Some authors have quantified the magnitude of learning externalities for technologies as justifications for particular subsidy levels (van Benthem et al., 2008; Andresen, 2012; Gerarden, 2017). However, it has been argued that feed-in premia, renewable portfolio standards, production tax credits, and other policies that subsidize energy (MWh) generation are inefficient means for achieving the goal of promoting technology improvement. In particular, if learning-by-doing is a function of cumulative MW investment rather than cumulative MWh production, then policies that are tied to *capacity installation* rather than *energy output* might be more effective in reducing technology costs (Newbery, 2012; Andor and Voss, 2016; Barquin et al., 2017; Huntington et al., 2017; Newbery et al., 2018). On the other hand, capacity-oriented policies are argued to be less cost-effective than well-designed energy subsidies for achieving energy penetration targets and reducing external environmental costs, at least in the short run (Meus et al. 2018).

The simplest capacity-focused policies could take the form of straight-forward per MW investment subsidies, such as auctions or investment tax credits. A more sophisticated variant, promoted by Newbery et al. (2018) (based on an auction used in China; Steinhilber, 2016), would instead solicit offers based on a per MWh cost, but would pay only up to a maximum number of MWh per MW of capacity over the lifetime of the project. The subsidy is paid out only as those MWh are generated, and the number of years of payments might also be limited. We term this policy the *mixed investment/output subsidy* policy. Compared to energy policies, the mixed policy will dampen incentives for very high capacity factor renewables; meanwhile, compared to pure capacity-based policies, generators with higher capacity factors will benefit by receiving more subsidies (up to the limit) and more quickly.

This paper addresses the cost and technology impacts of energy- versus capacity-based renewable policies using a detailed model of market-based generation investment and dispatch in Europe. The following simple example illustrates the general nature of these potential market impacts.

Say that two locations are available for renewable investments. Site 1 has a net cost of 100,000 €/MW/yr (where net costs are defined as capital costs minus revenues from the electricity market) and a capacity factor of 30%, while Site 2 has a net cost of 125,000 €/MW/yr and a capacity factor of 40%. Each location can accommodate 600 MW of investment. Assuming competitive conditions such that each site bids its levelized cost of energy, then an energy-based solicitation for 1,500,000 MWh of renewable energy per year would result in Site 2 being selected to provide that energy, installing 428.1 MW of capacity at a cost of 35.7 €/MWh (compared to Site 1's cost-based offer of 38.1 €/MWh). These results are summarized in the first case in Table 1. The total cost would be 53.5 M€/yr (= 1,500,000*35.7). On the other hand, if that 428.1 MW of capacity was instead acquired through a capacity solicitation based on €/MW/yr offers (second case in Table 1), then the following would instead happen. Site 1 would win because its offer of 100,000 €/MW/yr would undercut Site 2's offer of 125,000 €/MW/yr. Total cost would fall to be 42.8 M€/yr (=428.1*100,000). So, if the objective is to maximize capacity installation to promote learning, then the capacity policy is a cheaper means of doing so (savings = 10.7 M€/yr = 53.5-42.8).

Continuing with the simple example, let's instead consider a situation in which the government has an implicit renewable energy goal of 1,500,000 MWh/yr, but uses a capacity mechanism to meet it by setting a sufficiently ambitious capacity target. This is third case in Table 1. The government would then have to acquire 570.8 MW from Site 2 to generate that amount of energy, at a total cost of 57.8 M€/yr. Compared to the energy-based solicitation, this capacity-based policy costs 3.8 M€/yr more (=57.1-53.5), but results in 142.7 MW more installed capacity. The tradeoff is clear: a capacity-based subsidy is a cheaper way to spur construction of capacity, but a more expensive way to achieve an implicit energy goal. But in the latter case, in exchange for that added expense, much more capacity might be built and more learning achieved.

Table 1. Simple comparison of energy- and capacity-based policies

	Energy-based policy (acquire 1,500,000 MWh/yr)			Capacity-based policy (acquire 428.1 MW)			Capacity-based policy (acquire 570.8 MW)		
	Capacity acquired MW	Energy acquired MWh/yr	Offer €/MWh	Capacity acquired MW	Energy acquired MWh/yr	Offer €/MW/yr	Capacity acquired MW	Energy acquired MWh/yr	Offer €/MW/yr
Site 1	0	0	38.1	428.1	0	100000	570.8	0	100000
Site 2	428.1	1500000	35.7	0	0	150000	0	0	150000
Total	428.1	1500000		428.1	0		570.8	0	
Total Cost (M€/yr)			53.55			42.81			57.08

Meanwhile, the mixed investment/output subsidy policy's outcome in this simple example depends on that policy's parameters concerning the ceiling on MWh/MW subsidies and the number of years that the subsidies would be paid, as well as the interest rate and other factors. Continuing with the simple example, say that the interest rate is 5%/yr; subsidies are paid at the end of the year in which production occurs; investments have a 20 year lifetime which is also the last year that the subsidy is paid; and the maximum allowed MWh/MW is 61,320 MWh/MW (equivalent to a 35% capacity factor over 20 years). Assume that the government accepts the lowest €/MWh bid subject to those conditions. Then the breakeven per MWh subsidy for Site 1 turns out to be 38.05 €/MWh (that amount paid over 20 years for its 52,560 MWh/MW of production would just cover the capital cost of 100,000 €/MW/yr, plus interest). In contrast, Site 2 requires a subsidy of 40.21 €/MWh (which it would receive for 61,320 MWh/MW of production over 17 years). Thus, in this case, Site 1 would win the mixed capacity/energy auction. On the other hand, if the auction's maximum payout is 64,824 MWh/MW and the interest rate equals 10%/yr, this would instead render Site 2 cheaper than Site 1 (37.44 vs. 38.05 €/MWh, respectively). Thus, the mixed policy is likely to produce an outcome between the pure capacity and energy ends of the spectrum, with the exact outcome depending on the policy's exact rules as well as the interest rate.

This simple example shows that choice of capacity vs. energy-based subsidy could significantly affect the amount and mix of renewable energy investment, and its cost. In this paper, we ask what the outcomes would be in a much more realistic context – the European Union (including the UK, Norway, and Switzerland), accounting for varying market conditions, transmission limitations, and renewable energy development opportunities across the continent. In particular, we compare the impact of energy-focused (feed-in premium or renewable portfolio standard (RPS)) and capacity-focused (investment subsidies) renewable policies upon the EU-wide electric power market in 2030 using an electric power market equilibrium model. We use an power market model in order to determine what renewable investments would earn from selling energy and the resulting net costs that the investment must then recover from subsidies. These net costs must account for the value of power at different times and places, which in turn depends on the simultaneous interaction of supply and demand throughout the network; analysis methods that focus only on renewable resource capital and operating costs will miss these crucial interactions.

The specific question we focus on is the following:

> *How do the different policies impact the mix of renewable and non-renewable generation investment, electricity costs, renewable output, the amount of subsidies, and consumer prices in the year 2030? Specifically, do capacity-based policies result in significantly more investment and possibly learning?*

We also consider the mixed capacity/energy subsidy policy; as we show later, its result is a mix of investments that lies between the mixes incented by the pure energy and pure capacity subsidy policies. We also examine the interaction of energy and capacity policies with policies concerning trading of renewable energy credits across country borders. In particular, we evaluate the efficiency of *national* policy targets for renewable electricity production or capacity (as a whole or per technology) and compare these with a cost-effective EU-wide allocation of renewable energy investment, given resource quality, network constraints and the structure of the electricity system in the various EU countries.

To address these issues, we use COMPETES, an EU-wide transmission-constrained power market model, which we have enhanced to simulate both generation investment and operations decisions for the year 2030 (Özdemir et al., 2013, 2016). The regional coverage and transmission grid of the model are shown in Fig. 1. In contrast, other analyses of renewable electric energy policies in Europe have often identified best locations and technologies based on levelized costs or other metrics that disregard the space- and timing-specific value of their electricity output (e.g., del Rio et al., 2017). COMPETES uses linear programming to simulate the equilibrium in a market in which generation decisions simultaneously consider the effect of development costs, subsidies, and energy market revenues on profitability. The calculated energy prices and renewable subsidies are the result of the clearing of supply and demand for energy as well as for renewable capacity or energy, depending on the policy.

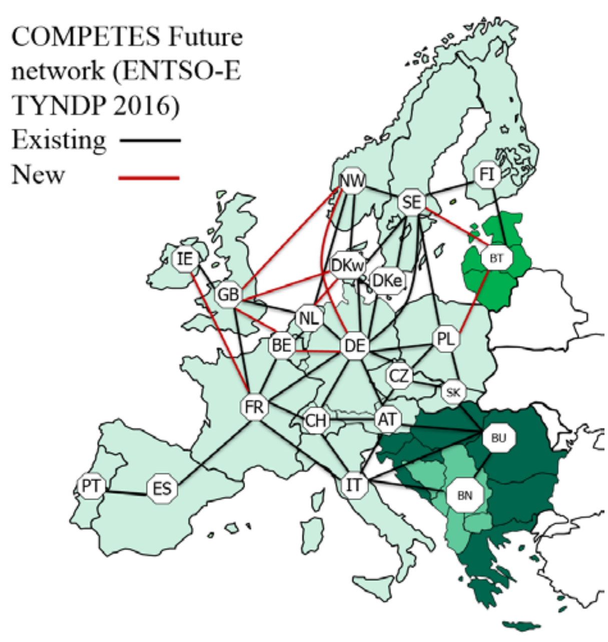


Fig. 1 The geographical scope of COMPETES

The paper is organized as follows. In Section 2, we provide a brief review of the literature on model-based analyses of renewable energy policies in order to situate the capacity- vs energy-subsidy question relative to analyses of the many other important questions concerning renewable policy. Then Section 3 summarizes the version of the COMPETES model used here. In Section 4, we present results concerning the impacts of capacity, energy, and mixed capacity-energy policies, as well as the effects of country specific targets as opposed to free trade of renewable energy or capacity credits among countries. Appendices present technical details about the formulation of the mixed capacity/energy policy model, and country-specific results concerning renewable capacity investments, annual energy prices, and energy market revenues earned by photovoltaic (PV) and wind investments.

2. Literature review: Analysis of renewable electricity policies

Renewable electricity policy in the EU as well as elsewhere is in flux (e.g., Banja et al., 2013; Resch, 2017). On one hand, targets in some places, such as Hawaii or California, have been ratcheted up as far as 100%. On the other hand, many jurisdictions are fine-tuning policies in an attempt to lower the cost of achieving those goals as the inefficiencies inherent in existing policies become more apparent (Neuhoff et al., 2016). There is a huge literature that addresses the economic and environmental costs and benefits of different policy designs, addressing five basic sets of questions summarized below. We limit ourselves to citing illustrative examples of each set because it is not possible to thoroughly cover the huge literature on renewables here.

The first set of questions asks: How large are the external environmental costs of electric power, how do they depend on location and timing of power consumption, and how do renewable policies affect those costs? For instance, one study shows how development of relatively low quality renewable resources in the eastern US would more effectively reduce the health costs of air pollution than development in the western US where resources are cheaper and more abundant (Siler-Evans et al., 2013).

Perhaps the largest set of analyses address the second set of questions: accounting for the response of the energy market to subsidies, how efficient are alternative subsidy mechanisms in terms of achieving multiple societal goals? These goals can include maximizing clean energy generation and minimizing emissions (which are not necessarily the same thing); minimizing cost and energy prices (also not the same thing; Fischer, 2010); fairly distributing of cost burdens and environmental benefits; providing leadership by example; accelerating reduction of renewable costs from learning-by-doing and research (Fischer and Newell, 2008); and limiting landscape and other direct environmental impacts of renewables. Policies considered can include supply-push policies such as renewable portfolio standards/obligations, auctions and tenders, feed-in tariffs, feed-in premia, and auctions of publicly owned-sites, as well as demand-pull policies such as green pricing and marketing (Huntington et al., 2017; del Rio et al., 2017; Resch 2018). For instance, Beurskens (2011) compares several of these policies for the Netherlands within the context of EU-wide markets and policies.

The third set of questions addresses the interplay of multiple simultaneous policies. It asks questions such as: what is the combined effect on costs, emissions, and renewable development of the coexistence of local, federal, and international renewable policies, or simultaneous pollution limitations and renewable subsidies? Many studies ask whether mixes of policies result in inefficiencies in achieving society's overall goals, or if they instead provide important complementarities (del Rio, 2017). Others suggest ways to adjust the policies to lessen conflicts or inefficiencies (Richstein et al., 2015).

A fourth set of analyses looks at how renewable policies interact with market failures in the electricity market. Examples include retail prices that fail to reflect the dynamics and geography of marginal costs, or the presence of market power in generation (Koutstaal et al., 2009; Tanaka and Chen, 2013).

The fifth and final set investigates the effects of particular implementations of individual policies. Some examples include the cost and emissions effects of allowing renewable credits to be traded across multiple jurisdictions (Perez et al., 2016; Unteutsch, 2014; Green et al., 2016; Meus et al., 2018); approaches to the "gap filling" that will be necessary if EU-wide targets will not be attained by reliance on individual country targets alone (Resch, 2017); separate targets for different classes of renewable technologies ("carve outs") (Kreiss et al., 2018); the banking of renewable credits in order to dampen year-to-year variations; and rules regarding the "additionality" of renewable energy sold as green power.

Nearly all market simulation-based analyses of these five sets of questions consider policies that subsidize renewable energy (MWh) rather than capacity (MW), since capacity-based mechanisms have been used far less in practice than energy-oriented instruments. Exceptions are the theoretical analyses by Newbery et al. (2018) and Barquin et al. (2017), who discuss the mechanics and possible advantages of capacity-based auctions using highly simplified examples. The question of capacity versus energy policies that they address is becoming more important as some policy makers ask whether there are more cost-effective ways to accelerate learning and technology improvement.

Thus, our analysis is unique in its focus on the market impacts of capacity-oriented vs energy-oriented policies while considering a realistic landscape of loads and resource characteristics, as well as fossil generators and grid limitations. In the next section, we summarize the COMPETES market modelling methodology as well as the assumptions made.

3. Model Description

We describe our modelling approach in two steps. First, we pose a static market equilibrium problem for a single year that assumes perfect competition (price-taking behavior) among all market parties, including renewable and non-renewable energy generators and the transmission system operator. Second, we state a single optimization problem for each renewable subsidy mechanism that is equivalent to the market equilibrium problem. This problem maximizes the sum of consumer-, transmission-, and producer surpluses (market surplus), subject to the relevant policy constraint. To start with, we define our notation.

Sets and Indices

H Set of hours, indexed h, each representing a sample of a combination of load and renewable output. $H(s)$ is the set of hours in season s. Note that because the model represents less than 8760 hours per year for computational reasons, a given "hour" h actually represents a subset of individual hours, and so its variables are weighted by the number of hours in the subset in the objective function.

I Set of nodes, indexed i, j

I_n Set of supply nodes of firm $n \in N$

I_v Set of supply nodes of hydro generator $v \in V$

K_n Set of supply technologies of firm $n \in N$, indexed k. K is the superset of these technologies

L Set of cross-border transmission lines, indexed l

N Set of generation firms, indexed n

R_n Set of renewable technologies of firm n (i.e., wind and solar), indexed $r \in R \subset K$

S Set of seasons, indexed s

V Set of hydro power generators firms, indexed v

Parameters

AIC_{ik} Annualized capital cost of generation capacity [$\frac{€}{MW}/yr$]

B, T Maximum hours of output [MWh/MW] qualifying for subsidy hours, and maximum number of years of payments, respectively, in a mixed investment/output capacity auction

D_{ih} Fixed electricity demand per hour [MW]

$EFLH_{ir}$ Equivalent full load hours of renewable generator [*hr/yr*]

$\overline{e}, \underline{e}$ Max, min state of charge for hydro pumped storage (or, more generally, other within-day energy storage) (default: $\overline{e} = 1, \underline{e} = 0$)

FLH_{ir} Full load hours of renewable generator [*hr/yr*]

$\bar{G}$ Target minimum renewable energy capacity in a capacity auction [MW]

IR Discount rate [1/yr]

MC_{ik} Marginal cost of generated energy [$\frac{€}{MWh}$]

NH_h Number of sample hours per year corresponding to hour *h* [1/*yr*]

NTC_l Net transfer capacity of cross-border transmission line [MW]

P_{vis}^{hydro} Seasonal hydro generation [MWh]

$\overline{P}_{vih}^{max}$ Maximum conventional hydro capacity, which can vary over the year [MW]

$\overline{P}_{vih}^{ror}$ Minimum run of river (ROR) generation, which can vary over the year [MW].

PS_{vi} Max charge/discharge capacity of storage [MW]

SC_{vi} Max storage level [MWh].

T_{ik} Economic lifetime of generator investment [yr]

$\bar{V}$ Equivalenced annual minimum renewable energy target in a mixed investment/output capacity auction [MWh]

Y_{nik}^0 Existing capacity of generator in 2030 [MW]

α_{ikh} Maximum capacity factor of generator

τ_{vi} Cycle efficiency of pumped hydro storage ($\tau_{vi} \in [0,1]$)

Φ_{il} Node-line incidence matrix of transmission lines

ϕ Target minimum renewable share of total MWh electricity production in an feed-in premium or renewable portfolio standards (RPS) mechanism, $\phi \in [0,1]$

Decision variables

a_{ih} Net injection into transmission grid at node i [MW].

ch_{vih} Charge level of hydro pump storage [MW].

ds_{vih} Discharge level of hydro pump storage [MW].

$\overline{f_{lh}}, \underline{f_{lh}}$ Power flows on transmission line l [MW].

g_{nikh} Generation dispatch level [MW].

g_{vih}^{hydro} Conventional hydro generation [MW].

p_{ih}^{*} Locational marginal electricity price [$\frac{€}{MWh}$]

SOC_{vih} Storage level of hydro pump storage [MWh].

ue_{ih} Unserved demand at node i [MW].

y_{nik} Generation capacity investment [MW].

λ^{*} Green certificate price for a renewable portfolio standards (RPS) mechanism [$\frac{€}{MWh}$]

β^{*} Clearing price of a capacity auction [$\frac{€}{MW}$]

γ^{*} Clearing price of a mixed investment/output capacity auction [$\frac{€}{MWh}$]

3.1. Market equilibrium problem

A market equilibrium assuming competitive conditions has two characteristics. First, each market party pursues its own objective (its profit) and believes that it cannot increase its surplus by deviating from the equilibrium solution. This is modelled by formulating a profit maximization problem of each market participant such as generators, consumers, and transmission system operators. The second characteristic is that the market clears at a wholesale price where power supply equals demand at each node in the network. Similar clearing conditions also apply to reserve and renewable energy/capacity markets, as appropriate. One approach to modelling market equilibria is to concatenate the first-order conditions for each market party's problem with market clearing equalities, yielding a complementarity problem (Gabriel et al., 2012). Complementarity problems can be solved either by specialized algorithms or, in special cases, by instead formulating and solving an equivalent single optimization model. Real-world problems lead to large scale complementarity models that are computationally challenging to solve. Fortunately, we are able here to use the single optimization problem approach, which allows us to solve large scale systems with millions of variables.

Before presenting the single optimization problem that we actually solve, we first describe the optimization problem of each market player in this section in order to make the assumptions of the model transparent. We assume perfect competition in which each market player is a price taker. Price-taking behavior can be modelled by treating price (which is signaled by an asterisk *) as an exogenous parameter in each market player's profit objective, even though price is endogenous to the market as a whole. We present the problem of renewable generators receiving remunerations under three alternative market-based renewable support schemes, namely a renewable portfolio standard (RPS) or energy-based policy, a capacity auction, and a mixed investment/output capacity auction proposed by Newbery et al. (2018).

To preserve computational tractability, the model below calculates an equilibrium for a single year rather than for a multiple year time horizon. We omit details on reserves markets and unit commitment constraints, which have been used in other COMPETES applications (e.g., van Hout et al., 2017; Hytowitz, 2018). Finally, for simplicity of notation and to explore the general impact of energy versus capacity policies, the renewable policies we show in the model equations below are technology-neutral with the same level of subsidy applied to all renewable sources, and assume a single EU-wide target. However, later in this paper, we solve generalizations of the model that simulate markets with technology and country-specific targets.

3.1.1. Generator problems

Each firm chooses its generation production and capacity in conventional and/or renewable technologies in order to maximize its annualized profits. The profits of a generator depend on the market price it earns for selling electricity in the spot market and the subsidy it receives for the MWh renewable generation or MW capacity installed. Below, we formulate the problem of an electricity firm operating in an energy-only market without a renewable subsidy, followed by formulations in which generators also participate in one of three alternative market-based renewable support schemes.

Energy-only market

We first consider the generators' problem in an energy-only market without any renewable support mechanism. In an energy-only market, the profits of a generator depend on the market price, p^*_{ih}, it earns for selling electricity in the spot market. For each firm $n \in N$,

$$\max \quad \sum_{i \in I_n, k \in K_n, h \in H} NH_h (p^*_{ih} - MC_{ik}) g_{nikh} - \sum_{i \in I_n, k \in K_n} AIC_{ik}\, y_{nik} \tag{1}$$

$$\text{subject to (s.t.)} \quad g_{nikh} \leq \alpha_{ikh}(Y^0_{nik} + y_{nik}) \qquad \forall i \in I_n, k \in K_n, h \in H \tag{2}$$

$$g_{nikh}, y_{nik} \geq 0 \qquad \forall i \in I_n, k \in K_n, h \in H, \tag{3}$$

where MC_{ik} is the marginal generation cost and AIC_{ik} is the annualized investment (capital) cost of generation capacity. The objective function (1) maximizes the gross margins earned from the spot market minus the investment costs of the capacities installed. Constraint (2) limits the maximum generating capacity of each unit and (3) is the non-negativity constraint. To account for variability of renewable output, the capacity of each technology is multiplied by a coefficient α_{ikh} which takes values less than or equal to one, and varies per hour or season depending on the technology and location of the generator. This model can be generalized to include nonlinear production cost functions, start-up costs, ramp limitations, and the sale of operating and installed reserve capacity (e.g., Brouwer et. al, 2016; van Hout et al., 2014; van Hout et al., 2017; Özdemir et al., 2014; Özdemir et al., 2017; Sijm et al., 2017).

Energy-based renewable policy

In an electricity market with *energy*-focused renewable support policies, firm n receives an energy subsidy per MWh of renewable generation (i.e, wind, solar-PV, biomass, and geothermal) in addition to the gross margin they earn from selling electricity to the power market. The renewable energy subsidy we consider is a feed-in premium type of instrument (equivalently, a RPS) or a green certificate price. Consequently, producers will have an incentive to optimize production at locations where local resources are such that the levelized cost of energy is low while also taking into account the local market value of the electricity production. With other types of energy subsidies such as, for example, a fixed feed-in tariff, there is only an incentive to generate at the lowest possible investment and O&M costs, and the value of the electricity provided to the market does not play a role in the decision of where to produce.

For each firm $n \in N$,

$$\max \sum_{i \in I_n, k \in K_n, h \in H} NH_h (p_{ih}^* - MC_{ik}) g_{nikh} + \lambda^* \sum_{i \in I_n, r \in R_n, h \in H} NH_h g_{nirh} - \sum_{i \in I_n, k \in K_n} AIC_{ik}\, y_{nik} \qquad (4)$$

$$\text{s.t. } Constraints\ (2), (3).$$

Both conventional and renewable generators of firm n earn profits from the spot market represented by the first component of the objective function in (4). Renewable electricity generators owned by firm n (denoted by r) receive a per MWh payment λ^* in addition to the revenue they earn from selling electricity on the electricity market.

Capacity-based renewable policies

The rationale for these policies is that learning might more related to cumulative capacity installations than to MWh production *per se.* There are several possible variants of these policies that might, for instance, adjust subsidies to reflect relative capacity factors (in which case the policies would take on more of an energy-based flavor). Another variant might reward capacity whose output might coincide better with system demand peaks, although the fact that installations would earn revenues in the energy market would likely mean that such facilities would earn a higher price for their production.

Capacity Auction: The first type of capacity-based renewable support policy we consider is a *capacity* auction. In a *capacity* auction with an EU-wide total renewable capacity target, firm n receives a capacity payment per MW of renewable capacity that contributes to the target:

$$\max \sum_{i \in I_n, k \in K_n, h \in H} NH_h (p_{ih}^* - MC_{ik}) g_{nikh} + \beta^* \sum_{i \in I_n, r \in R_n} y_{nir} - \sum_{i \in I_n, k \in K_n} AIC_{ik}\, y_{nik} \qquad (5)$$

$$\text{s.t. } Constraints\ (2), (3),$$

where β^* is the clearing price of the capacity auction.

Mixed investment/output subsidy: Another variant of capacity-focused support policy is inspired by Newbery et al. (2018) who propose a type of mixed investment/output subsidy. In this proposal, a MWh payment determined by an auction which would apply to production up to a specified maximum number of MWh per MW of capacity, defined as B—e.g., 20,000 MWh/MW over the lifetime of renewable generators. Payments would not be made for more than T years. In a multiyear version of COMPETES, it would be possible to track payments for qualifying MWh in each year to a generator installed at a given time, and to discount them appropriately. In this static (single year) version, we instead calculate the equivalent annualized subsidy stream (in €/MW of capacity/yr), based on the lifetime of the asset, the maximum number of years that MWh payments can be collected, and the maximum MWh/MW. For a given MW of, say, wind capacity, this equivalent annualized revenue will in general be less if an asset has a lower capacity factor or shorter life, and/or if the policy's maximum years of payments and MWh/MW is smaller. The overall annualized subsidy is defined as $\gamma^* \sum_{i,r} EFLH_{nir} y_{nir}$, where $\gamma^* EFLH_{ir}$ is the equivalenced capacity payment per MW of renewable capacity investment of type *r* at location *i*. Appendix A derives the formula for $EFLH_{ir}$.

Given these assumptions, we can formulate the generating company *n*'s problem with the equivalenced annualized costs and revenues as:

$$\max \sum_{i \in I_n, k \in K_n, h \in H} NH_h (p^*_{ih} - MC_{ik}) g_{nikh} + \gamma^* \sum_{i \in I_n, r \in R_n} EFLH_{ir} y_{nir} - \sum_{i \in I_n, k \in K_n} AIC_{ik}\, y_{nik} \quad (6)$$

$$\text{s.t. } Constraints\ (2), (3).$$

3.1.2. Hydropower generator's problem

We model seasonal and daily electricity storage from hydro. Hourly Run-of-River (RoR) generation, $\overline{P}^{ror}_{vih}$, is assumed to be must-run generation, given monthly data on the share of RoR per country. Meanwhile, flexible generation from hydro storage is endogenously distributed over the hours within a season such that the sum of the hourly hydro generation is equal to the total seasonal hydro generation P^{hydro}_{vis}, based on historical (2011-2016) seasonal availability of water reservoir levels. Finally, generation from hydro pump storage is modelled such that the pump storage operators maximize their net revenues by charging and discharging electrical energy within a day. These electricity storage operators buy power by charging during low priced hours and sell power by discharging during high priced hours. By doing so, they increase or decrease system demand for electricity and contribute to the flexibility for balancing generation and demand. For each hydro generator $v \in V$:

$$max \sum_{i \in I_v, h \in H} [NH_h p^*_{ih} \, (ds_{vih} - ch_{vih}) + NH_h p^*_{ih} g^{hydro}_{vih}] \quad (7)$$

$$s.t. \quad SOC_{vih} = SOC_{vi,h-1} + ch_{vih} - ds_{vih}/\tau_{vi} \qquad \forall\, i \in I_v, h \in H \quad (8)$$

$$\underline{e} * SC_{vi} \le SOC_{vih} \le \overline{e} * SC_{vi} \qquad \forall\, i \in I_v, h \in H \quad (9)$$

$$0 \le ds_{vih} \le PS_{vi} \qquad \forall\, i \in I_v, h \in H \quad (10)$$

$$0 \le ch_{vih} \le PS_{vi} \qquad \forall\, i \in I_v, h \in H \quad (11)$$

$$\sum_{h \in S(h)} NH_h g^{hydro}_{vih} = P^{hydro}_{vis} \qquad \forall\, i \in I_v, s \in S \quad (12)$$

$$\overline{P}^{ror}_{vih} \le g^{hydro}_{vih} \le \overline{P}^{max}_{vih} \qquad \forall\, i \in I_v, h \in H. \quad (13)$$

The objective function maximizes the revenues of generation by conventional hydro generators and revenues of discharging minus the costs of charging electrical energy by hydro pump storage generators. Constraints (8)-(11) represent the operation of hydro pump storage. Note that in (8), *h*-1 is the hour that chronologically precedes hour *h*, with the exception of the first hour of the day, which is assumed to be preceded by the last hour of the same day. Constraints (12) and (13) represent the dispatch of power generation from conventional hydro storage bounded by the minimum ROR generation and maximum capacity, based on the monthly/seasonal availability of water reservoir levels.

3.1.3. Transmission system operator's problem

The transmission system operator (TSO) is modeled as a power pool operator: it buys power directly from generators and sells it to consumers. It can be shown that the outcome is the same as modeling a market where producers sell bilaterally to consumers, and pay a transmission fee that efficiently rations grid capacity. The TSO is assumed to be a single entity, although in reality there are multiple operators, one or more per country. The operator's objective is to maximize the value of its transmission services (i.e., revenues obtained from this arbitrage) subject to the cross-border flows limited by the net transfer capability of transmission lines (NTC) between countries:

$$\max \quad \sum_{i\in I,h\in H} NH_h p_{ih}^* a_{ih} \qquad (14)$$

$$\text{s.t.} \quad \sum_l \Phi_{il}(\overline{f_{lh}} - \underline{f_{lh}}) - a_{ih} = 0 \qquad \forall\, i \in I, h \in H \qquad (15)$$

$$\sum_i a_{ih} = 0 \qquad \forall\, h \in H \qquad (16)$$

$$\overline{f_{lh}} \le NTC_l \qquad \forall\, l \in L, h \in H \qquad (17)$$

$$\underline{f_{lh}} \le NTC_l \qquad \forall\, l \in L, h \in H \qquad (18)$$

$$\overline{f_{lh}},\ \underline{f_{lh}} \ge 0 \qquad \forall\, l \in L, h \in H. \qquad (19)$$

Constraints (15) and (16) are the arbitrage constraints balancing the import and export flows between countries, with (15) being the energy balance at i from the operator's point of view and (16) ensuring that total supply and demand are in balance. Constraints (17) and (18) are the maximum and minimum flow limits of cross-border transmission lines. Constraints (19) impose non-negativity. In order to preserve computational tractability, we did not consider optimal transmission capacity investments, Kirchhoff's Voltage Law constraints, or transmission losses; however, the TSO's problem can be extended to include these constraints (Ozdemir et al., 2016).

3.1.4. Market clearing conditions under alternative renewable support mechanisms

The market clearing conditions for the wholesale electricity market correspond to the energy balance, accounting for imports/exports, generation, discharge/charge from hydro pump storage, and demand net of unserved energy for each node at every hour:

$$a_{ih} + \sum_{n\in N,k\in K_n} g_{nikh} + \sum_{v\in V} g_{vih}^{hydro} + ds_{vih} - ch_{vih} + ue_{ih} = D_{ih} \quad (p_{ih}^*) \qquad \forall\, i \in I, h \in H. \qquad (20)$$

$$0 \le ue_{ih} \perp (VOLL - p_{ih}^*) \ge 0 \qquad \forall\, i \in I, h \in H. \qquad (21)$$

The Lagrange multipliers of market conditions (20) correspond to the hours-weighted (NH_h) electricity market prices, p_{ih}^*, that are endogenous to the whole system. We consider fixed demand profiles. Market condition (21) allows the fixed demand to be curtailed at an assumed price cap or value of loss load (VOLL). The "perp" symbol $\perp$ indicates that the product of the expressions on the left and right of that symbol must be zero.

Energy-based renewable policy

We model the *energy*-focused renewable support policy as a market-based support scheme, i.e., a RPS with an EU-wide renewable obligation target and tradable green certificates. An obligation target, denoted by $\phi \in [0,1]$, is the minimum share of renewable energy sources in total electricity production.

The market clearing condition (22) corresponds to the certificate/quota constraint set by the regulating authorities. The Lagrange multiplier, λ^*, of this constraint is the certificate value needed to achieve the obligation target. Producers could choose to generate more than the target, in which case the certificate value will be zero.

$$0 \leq \lambda^* \perp \left(\sum_{n\in N, i\in I_n, r\in R_n, h\in H} NH_h g_{nirh} - \phi \sum_{i\in I, h\in H} NH_h D_{ih}\right) \geq 0. \qquad (22)$$

Capacity-based renewable policies

Capacity Auction: We also model *capacity*-focused renewable support policies as market-based support schemes. The first variant of a capacity support scheme is represented by a capacity auction with an EU-wide total capacity target $\bar{G}$. The firms contributing to the target receive remuneration β^* per MW renewable generation capacity, which is the clearing price of the capacity target constraint (23).

$$0 \leq \beta^* \perp \left(\sum_{n\in N, i\in I_n, r\in R_n} y_{nir} - \bar{G}\right) \geq 0\ . \qquad (23)$$

Mixed investment/output subsidy: In the second variant of a capacity support scheme (the mixed investment/output subsidy), any firm investing in new renewable generation capacity will receive €/MWh payments determined by an auction, with the payments being made in the year of production. The lowest per MWh bids into this auction are awarded payments that are upper bounded by two constraints: (1) there cannot be payments for more than a predetermined number *B* of MWh per MW capacity over the lifetime of renewable generators, and (2) payments are made for no more than *T* years of payments. As Appendix A shows, this payment is equivalent to imposing the following market clearing constraint, whose shadow price is the subsidy. The constraint says that the annual contributions of all firms to an equivalent MWh/yr target $\bar{V}$ must satisfy:

$$0 \leq \gamma^* \perp \left(\sum_{n\in N, i\in I_n, r\in R_n} EFLH_{nir} y_{nir} - \bar{V}\right) \geq 0\ , \qquad (24)$$

where $EFLH_{nir}$ is the annualized equivalent full load hours (hr/yr), discounting future payments/MWh, as discussed in Appendix A. When multiplied by capacity, the result is in an annual equivalent energy production in MWh/yr. The Lagrange multiplier γ^* (€/MWh) is the clearing price of the auction.

3.1.5. Equilibrium problem

Since the surplus maximization problems for the generators, TSO, storage operators given above are convex optimizations (each optimizing a concave objective function subject to a linear set of constraints), a point satisfying their first-order (Kuhn-Karush-Tucker, KKT) conditions is sufficient for global optimality. Hence one can obtain the equilibrium by solving the KKT conditions for every player simultaneously in an equilibrium model. The equilibrium model combines the first-order (Kuhn-Karush-Tucker, KKT) conditions of the surplus maximization problems for the generators, TSO, storage operators with the energy and renewable market clearing conditions (Sections 3.1.1-3.1.4, respectively).

For instance, the equilibrium problem of the energy-only market without a renewable support scheme is constructed by concatenating the KKT conditions of all the generators' problem (1)-(3) and (7)-(13), the TSO's problem (14)-(19), and the energy market clearing conditions (20)-(21). For energy or capacity-focused renewable support schemes, the KKT conditions of renewable generators are adjusted to account for renewable subsidies, and the renewable market clearing condition for the relevant policy is included in the equilibrium model. As an illustration, the KKT conditions for the generators and TSO are given in Appendix B.

When correctly defined, the KKT and market clearing conditions together define a square system of complementarity and/or equality conditions, in which the number of conditions equals the number of variables. This system can be solved for the market equilibrium by using commercial complementarity solvers such as PATH (Dirkse and Ferris, 1995). However, solving complementary problems for large-scale systems are computationally challenging and is limited to few thousands of variables in practice. Therefore, we obtain the equilibrium by formulating a single linear optimization problem which can be solved for problems with millions of variables.

3.2. Equivalent optimization problem

In this section, we formulate a single linear program that is equivalent to the electricity market with profit maximizing generators, TSOs, and storage operators all subject to the relevant energy and renewables market clearing conditions. The set of KKT conditions of such a single linear program is equivalent to the combined sets of KKT conditions of all the generators' problem, TSO's problem, and the market clearing conditions under each renewable support scheme defined in Section 3.1.5 (e.g., KKT conditions (26)-(47) given in Appendix B). In general, formulation of a single equivalent optimization problem may not be possible for any particular market equilibrium problem, but it is often feasible for equilibrium problems formulated under the assumption of perfect competition (Gabriel et al., 2012).

The linear program below is an integrated model of economic power dispatch and generation capacity planning, taking into account generation intermittency and the cross-border transmission constraints between the countries. It is a stochastic linear program, with the scenarios being different sets of load and renewable conditions h, and its set of KKT conditions is sufficient for global optimality. Because the optimal solution of the linear program below must satisfy its KKT conditions (which is equivalent to the market equilibrium problem as defined by the combination of KKT and market clearing conditions defined in Section 3.1.5), it is therefore also a market equilibrium. The reverse is also true; that is, the solution of the electricity market equilibrium model defined in Section 3.1.5 maximizes social welfare (the negative of total cost), subject to the policy constraint. The linear program is:

$$\min \sum_{n\in N, i\in I_n, k\in K_n, h\in H} NH_h MC_{ik} g_{nikh} + \sum_{n\in N, i\in I_n, k\in K_n} AIC_{ik}\, y_{nik} + \sum_{i\in I, h\in H} VOLL\, ue_{ih} \quad (25)$$

$$\begin{aligned}
\text{s.t.}\quad & Generators'\ Constraints: && (2)-(3), && \forall\, n \in N\\
& Hydro\ Generators'\ Constraints: && (8)-(13), && \forall\, v \in V\\
& TSO's\ Constraints: && (15)-(19) &&\\
& Energy\ market\ clearing\ constraints: && (20) &&\\
& Renewable\ support\ policy\ constraint: && (22)\ or\ (23)\ or\ (24), &&
\end{aligned}$$

where the objective function minimizes total electricity operation and investment costs, including a penalty for unserved demand. For an electricity market without any renewable support policy, the constraint set consists of the constraints of all the market participants plus the energy market clearing conditions (20) whose Lagrange multipliers are equal to the locational electricity market prices. Depending on the renewable support policy, one of the market clearing conditions (22), (23), or (24) is also included in the constraint set. (Note that in a linear program, only the right-hand inequality of a renewable complementarity condition needs to be included; the first order conditions of the LP automatically enforce the full complementarity condition.) The Lagrange multiplier of such renewable support policy constraints gives the clearing price of the auction with a renewable energy or capacity target.

4. Simulations of 2030 EU power market

4.1. Model Assumptions

We implement the modelling approach in Section 3 in the European market model COMPETES which includes 33 countries represented by 22 nodes[1] (Fig. 1). Transmission in COMPETES mimics an integrated EU network limited by the net transfer capabilities (NTC) between countries or regions. NTC values are estimated based on the 2016 Ten Year Network Development Plan of ENTSO-E (2016a). The model adopts zonal pricing which is the current market structure in the European Union. Given that COMPETES does not model transmission constraints within a country (with the exception of the DC link between Denmark East and Denmark West), the model is equivalent to locational marginal pricing. The net power costs for a given country are calculated assuming that power purchases and sales are settled at locational prices. The calculation of a country's net costs accounts for all within-country generation costs as well as transmission congestion rents, which are split by countries at either end of the connectors.

For initial installed capacities, we use the generation capacities given by ENTSO-E's Mid-Term Adequacy Forecast (MAF) scenario (ENTSO-E, 2016b) up to 2020, taking into account renewable policies and targets of 2020. The investments and/or decommissioning of nuclear until 2030 are assumed to be policy-driven and are exogenous to the model. The installed capacities of hydropower and biomass up to 2030 are also taken as exogenous, based on the Vision 1 scenario of ENTSO-E (ENTSO-E, 2016a). Given initial generation capacities and the ten-year network development plan of ENTSO-E, the model endogenously calculates the incremental investments in onshore wind, offshore wind, and solar-PV between 2020 and 2030 as well as the investments and decommissioning of gas and coal power plants. Annual investment costs of conventional generation technologies are estimated based on capital costs and economic lifetime assumptions in Ozdemir et al. (2013). Annual investment costs and potentials of onshore wind are estimated based on the 2013 EU Reference Scenario (Capros et al., 2013). The input data for offshore wind and solar-PV are taken from Resolve-E, which is a European market model for renewable electricity (Daniëls and Uyterlinde, 2005). The investment costs of solar-PV and offshore wind and their potentials in the Netherlands are based on the Dutch National Energy Outlook 2017 (Schoots et al., 2017). For all other EU countries, the potentials of solar-PV and offshore wind originate from Hallstead (2013) and Cameron et al. (2011), respectively. Costs are differentiated by country and, in the case of off-shore wind, several tranches with increasing capital costs are defined representing increasing distance from the shore.

The demand is perfectly inelastic and the annual consumption for all the countries in 2030 is in line with the Vision 1 scenario of ENTSO-E, 2016a. We assume the same fuel- and CO_2 prices as given by the

---

[1] COMPETES includes 26 EU members (excluding Malta and Cyprus) and 7 non-EU countries (i.e., Norway, Switzerland, and Balkan countries). Every country is represented by a single node, except Macedonia, Montenegro, Albania, Serbia and Bosnia-Herzegovina that are aggregated in a single node 'non-EU Balkan'; Romania, Greece, Bulgaria, Croatia, Slovenia, Hungary that are aggregated in a single node 'EU Balkan'; the Baltic countries; Luxembourg which is included in Germany; and Denmark, which split in two nodes due to its participation in two nonsynchronous networks.

Dutch National Energy Outlook (Schoots et al., 2017). Fuel prices in 2030 represent the New Policies Scenario of World Energy Outlook (WEO) 2016 (IEA, 2016). The CO_2 price in Schoots et al. (2017) is assumed to be 15 €2010/tonne CO2 in 2030,[2] , although we also do a sensitivity analysis based on 42 €/tonne. Our assumption is that the supply of offsets and carbon trades with other sectors are sufficiently elastic to maintain that price if power sector emissions change; other assumptions would be unlikely to significantly affect our comparison of the costs of energy vs. capacity policies.

COMPETES includes hourly variability of load, wind and solar generation. For practicality, we use a sample of 50 representative days of a year (i.e., 1200 hours out of 8760) for capturing load and renewable output variability within a year, sampled from 8 years of data from Gorm et al. (2015). For sampling, we employ the *k*-means clustering algorithm to cluster days with similar patterns of load, wind and solar generation. The *k*-means method groups the original set of observations (i.e., load, wind and solar-PV profiles) into n partitions or clusters with the objective of keeping the variance in each cluster to a minimum, where n is the number of days we use for our sample (Hartigan, 1975). For every resulting cluster, a single historical day that is closest to the cluster's centroid is selected as the representative day of that cluster, which is shown by Nahmmacher, 2016 to yield a better approximation than using the cluster's centroid itself. The weight assigned to each representative day, i.e., the number of days that are represented by the selected day, corresponds to the relative size of its cluster (i.e., number of historical days grouped in its cluster divided by the total number of days in the dataset). In this way, we account for both common load and variable renewable generation patterns represented by large clusters and the rare situations represented by small clusters. The weighted average of the sample may deviate from the average of the underlying historical time series. Therefore, the hourly data of the representative days are scaled to match the 2030 average capacity factors by country for wind and solar from the EU 2013 Reference Scenario (Capros et al., 2013).

4.2. Renewable support policy scenarios

We establish a scenario framework, summarized in Table 1, to compare a baseline scenario of no renewable policies with three EU-wide support policies achieving alternative levels of renewable energy and capacity targets. The renewable policies we consider, in general, assume a single EU-wide target without country-specific mandates, and furthermore assume that the same level of subsidy applies to all renewable sources. Of course, the reality of EU policy is that there are distinct programs for wind, solar, biomass, and hydropower, and each country has their own targets, with relatively limited opportunities for countries to satisfy their renewable requirements elsewhere. However, these simplifications allow us to explore the general impact of energy versus capacity policies upon the 2030 market. In sensitivity analyses, we consider country- and technology-specific targets as well. We do not attempt to quantify long-term learning that results from alternative levels of investment in the various technologies.

Although 2030 targets set by the EU explicitly rule out binding national renewable energy targets, the individual member states are putting in place policies to achieve their own targets. We also explore the efficiency of country-specific targets compared to an overall EU-target. To simulate national targets, we assume a MW-based policy with a minimum amount of solar, onshore wind, and offshore wind capacity based on targets reported by ENTSO-E's Sustainable Transition (ST) scenario (ENTSO-E, 2018). Furthermore, we assume no Renewable Energy Certificates (REC) trading among countries in that case,

[2] All the prices and monetary values in this paper are given in €2010.

under the assumption that the rules for renewable imports to qualify for national targets are so onerous that relatively negligible amounts of qualifying renewable developments will occur.

Table 1. *Overview of renewable support policy scenarios*

	RES support policy scenarios	**Implementation**	**Target variation in 2030**
Overall EU Target	Baseline	no renewable policies in 2030	No target
	Energy subsidy	Renewable portfolio standards (RPS)	Renewable electricity share targets up to 65%
	Capacity subsidy	Capacity auction for MW installations	Capacity target up to 550 GW (achieving up to 65% renewable electricity share)
	Mixed investment/output subsidy program (Newbery et al., 2018)	MW auction Payments made per MWh up to a maximum MWh/MW	MWh/MW target achieving up to 65% renewable electricity share
National target	Country specific targets	A MW-based policy with a minimum amount of solar, onshore wind, and offshore capacity	Based on renewable capacities in 2030 reported by ENTSO-E's Sustainable Transition (ST) scenario (ENTSO-E, 2018).

- In addition to the basic policy alternatives shown above, the following variants are also considered:All three renewable policies under a higher CO_2 price (€42/tonne, versus €15/tonne in the base case)
- Capacity based policies that set technology-specific targets. This might be rationalized under the assumption that some technologies have more opportunity for learning-based cost reductions than others.

4.3. The economic impacts of capacity vs. energy mechanisms

4.3.1. The costs of meeting MWh vs. MW targets

The total renewable electricity share in EU in the baseline scenario without renewable policies reaches to 47% in 2030—of which 24% is from wind energy and 5% is from solar-PV. This is comparable to economic penetrations given by the EU 2013 Reference Scenario with 22% wind and 6% solar-PV shares (Capros et al., 2013) and the Low Scenario of Wind Europe, 2017 with 22% wind share. In Fig. 2, we show the annualized cost (EU-wide) of meeting higher renewable MWh targets by the three EU-wide policies. The energy subsidy policy directly puts a floor under the total renewable MWh (equation (22)). To simulate the use of capacity and mixed policies to meet a MWh target, we needed to iteratively adjust the right hand sides of their constraints (equations (23) and (24), respectively) until enough capacity is built such that the annual renewable MWh meets the target. The latter runs simulate a situation in which policy makers use a capacity or mixed instrument to promote renewables, but have an implicit energy percentage target in mind.

These runs allow us to compare the incremental cost of increasing the renewable electricity share beyond the energy-market only level of 47% by using energy or capacity-focused policies. (Note that by cost, we mean the objective function (25), which includes generation investment and operations cost as well as customer outages.) Theory says that the most cost-effective way to reach a MWh target is by directly constraining MWh through energy-focused policies (Meus et al., 2018), and this is indeed the case (Fig. 2, left side). Although the capacity-focused policies result in similar costs for the less ambitious MWh targets, they become relatively more expensive as the targets get more aggressive. Using MWh feed-in premiums rather than capacity payments is cheaper because paying for the product that contributes directly to a desired target (MWh rather than MW) is the first-best way of meeting that target. For instance, at a renewable energy target of 65%, the capacity subsidy results in 58% higher incremental costs of renewables (compared to the base case of 47% renewables) than an energy subsidy (e.g., 11B €/yr for the RPS policy versus almost 18B €/yr for a capacity subsidy). On the other hand, that capacity policy results in much more capacity installation (99 GW less of wind, 271 GW more of solar, for a net increase of 173 GW, with round-off error).

We observe a reverse effect if the goal is instead to promote technology improvement through capacity installation. A capacity-focused policy is the cost-effective (first-best) way of reaching a certain capacity level for renewables, whereas achieving the same level of renewable capacity by an energy subsidy is more costly. For instance, the 377 GW of new renewables that results from the 65% RPS policy could also be achieved directly by capacity policy at an incremental cost that is 26% lower than the 11 B€/yr cost of the RPS policy (right side, Fig. 2). On the other hand, a capacity policy achieves only a 60% (rather than 65%) renewable share in total MWh electricity consumption.

Meanwhile, the mixed investment/output subsidy (MWh/MW capacity) falls in between these two cases as it has characteristics of both capacity and energy policies. For instance, the incremental cost of the mixed investment/output subsidy is 14B €/yr if that policy is used to achieve a 65% renewable electricity share, which is 28% higher than the energy subsidy policy's cost (11 B€/yr) and 22% lower than the capacity subsidy policy's cost (18B €/yr). It results in 57 GW less of wind and 156 GW more of solar-PV, with a net increase of 99 GW renewable capacity compared to the energy-based policy.

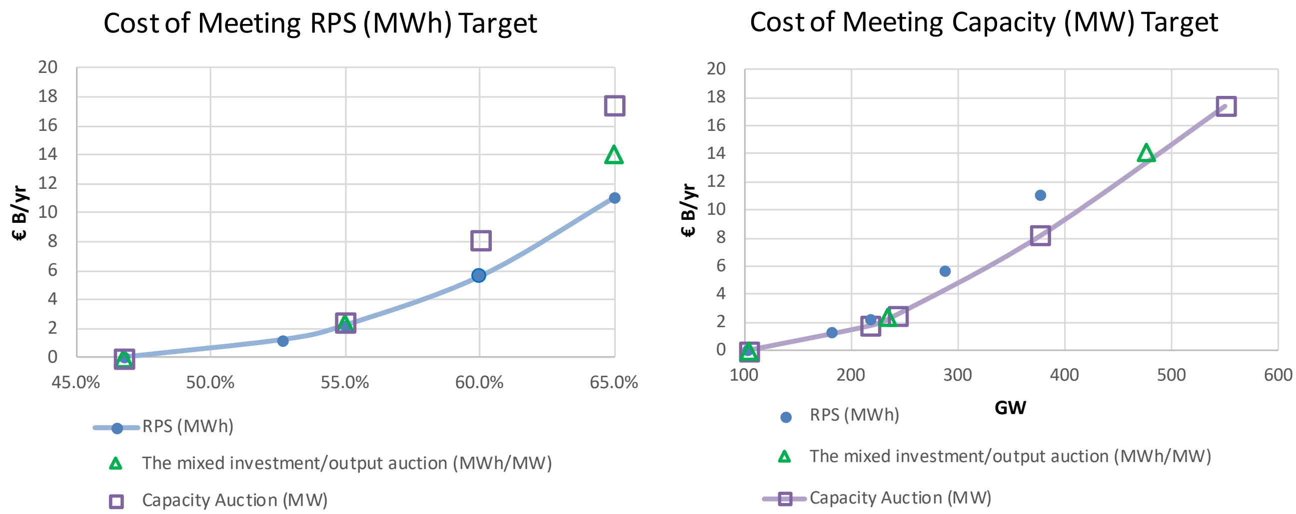
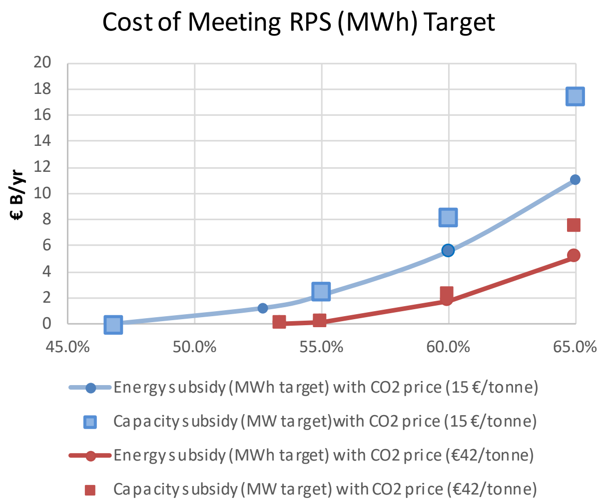


Fig. 2. Incremental generation cost/yr of meeting MWh vs MW targets under the three policies

The required subsidies to achieve the various targets are of interest. The marginal subsidy required for the RPS case (left side of Fig. 2) rises from zero (at an EU penetration of 47%) to 13 €/MWh (@55% penetration), rising to 21 (@60% penetration) and 33 (@65%). These values correspond to the shadow price of the RPS constraint in the model, and equal the slope of the solid curve in Fig. 2 (left). The implicit marginal subsidy of providing renewables by capacity policies is higher than by an RPS policy for penetrations of 60% or over, based on the slopes of their curves in that figure; for the pure capacity auction, the marginal cost is about double that of the RPS. On the other hand, the capacity policy has a lower marginal cost of achieving capacity goals. Based on the solid curve in Fig. 2 (right), the subsidy price for the capacity policies is 30204€/MW/yr for 243 GW of investment 47614€/MW/yr for 377 GW, and 57354€/MW/yr for 550 GW. The implicit marginal cost of providing that same capacity by an RPS energy-based policy instead is, of course, higher.

The inefficiencies identified in Fig. 2 depend on the price of carbon. In Fig. 2, an ETS price of €15/tonne is assumed; however, since carbon prices recently have been that high, it is of interest to consider higher values. Fig. 3 shows the impact of a higher carbon price (€42/tonne) on the energy- and basic capacity-based policies relative to the base case of Fig. 2. Two basic trends are evident. One is that the higher carbon price motivates a greater penetration of renewables (53% of energy compared to 47%) without the need for additional subsidy. Second is that the inefficiency resulting from choosing one type of policy to meet a different type of goal is diminished. Fig. 3 (left) shows that the cost increase from using a capacity auction to meet an energy goal of 65% falls by more than half, from about €7B/yr (€15/tonne) to less than €3B/yr (€42/tonne) (right most points in the figure). Meanwhile, Fig. 3 (right) indicates that use of an RPS energy-based policy to meet a capacity goal of 377 GW of renewables investment would cost about €3B/yr more than using a capacity policy under the lower carbon price, and only about €1.5B/yr more under the higher price. Thus, our conclusion that there are inefficiencies on the order of a billion €/yr from using one kind of policy to meet an ambitious goal of the other type still holds, but the magnitude of the effect is less.



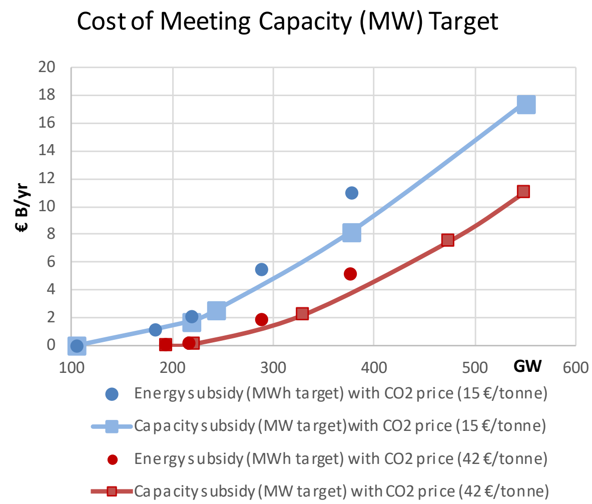


Fig. 3. Effects of carbon price on incremental generation cost/yr of MWh vs MW targets under energy- and capacity-based policies

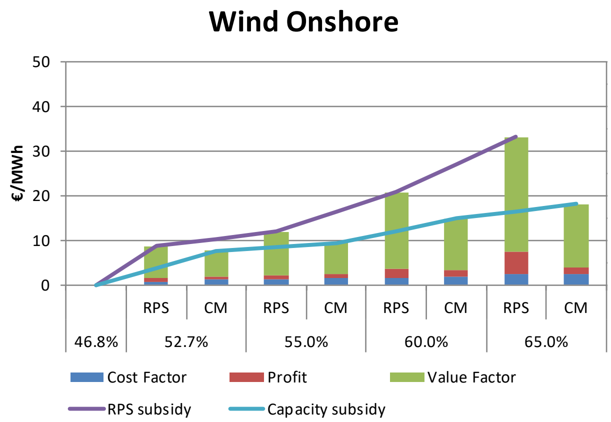
4.3.2. Where does the subsidy go?

The subsidy required to achieve a certain share of renewables increases as the targets get more ambitious. There are three factors contributing to the rise in subsidies: increases in capital costs because investments in renewables are taking place at more expensive locations; increases in scarcity rents (economic profit) earned by renewable generators whose investment levels have already reached their upper bound; and increases in required compensation to make up for the reduction in energy market value of renewables as a result of decreasing electricity prices. Here we ask: what are the relative contributions of these three factors to the expense of subsidies?

Fig. 4 shows the average amounts of subsidy for on-shore wind and solar-PV as a function of the total energy penetration, and how those subsidies are partitioned into the three sources (capital costs of more expensive sources, economic rents, and compensation for decreases in market value). The subsidy rises to as much as 43 €/MWh (equivalent) as penetration increases. The energy subsidy favors onshore wind investments since wind has higher a capacity factor and contributes directly to the MWh target, whereas the capacity subsidy supports more solar-PV investments since solar-PV has lower capital costs per MW. Consequently, the total amount of subsidy to solar is higher under the capacity policy than the energy policy (for a given energy target) (compare the two lines on the right side of Fig. 4), while the reverse is the case for wind (compare the two lines on the left side of the figure).

Meanwhile, profits (scarcity rents) are higher for wind in the energy subsidy case because of the full exploitation of onshore wind capacity at some attractive locations, and these economic rents increase as the subsidies increase.

An example is the case of onshore wind in Belgium under energy subsidies which is shown on the left side of 5; in comparison, this does not occur in Denmark-west because the resource is not fully exploited there (Fig. 5, right). On the other hand, there are no economic rents for solar-PV because the potential resource is not fully used in any region in any scenario.



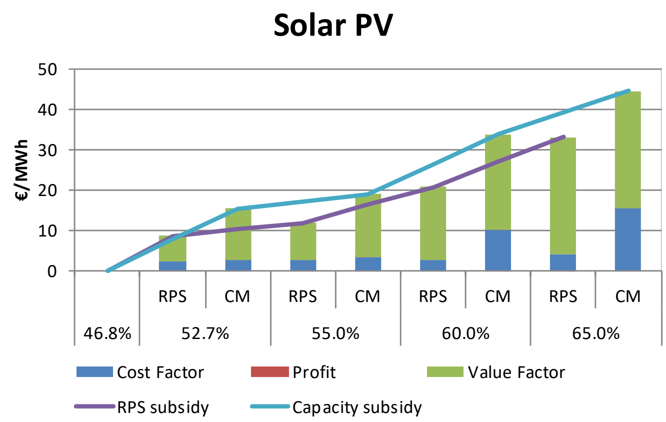
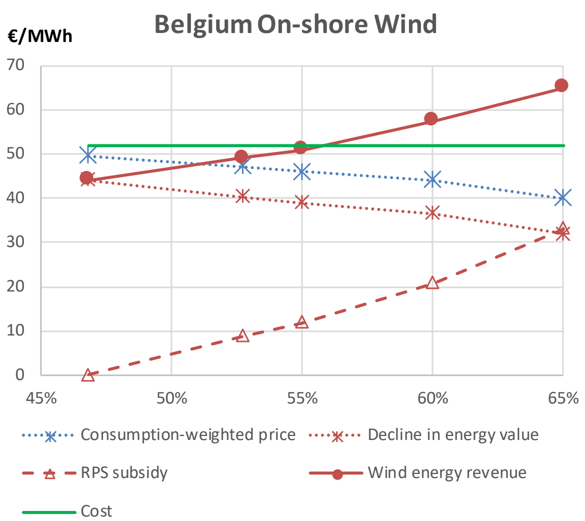


Fig. 4 The contribution of energy and capacity subsidies per unit output for onshore wind and solar-PV (to make up for rising renewable costs, provide scarcity rents, and to compensate for reduced value in the energy market)



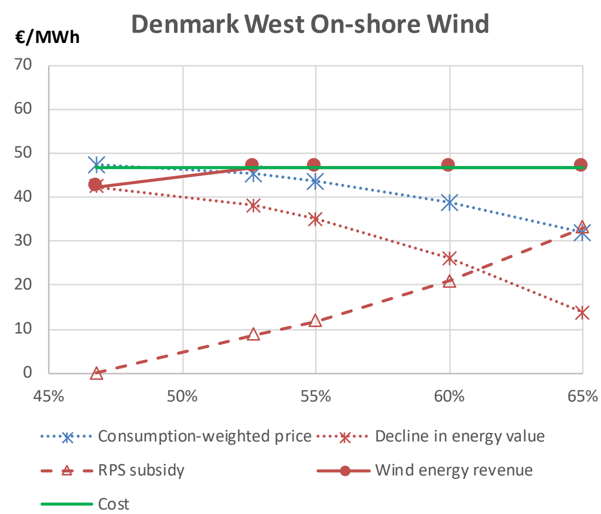


Fig. 5 Total market value and sources of revenues for onshore wind producers in Belgium (where the full potential is eventually developed) vs Denmark (where the its potential resource is not fully developed) under the RPS subsidy. Market Energy Price is the consumption weighted bulk power price, while Energy Value is the average revenue received by wind

We now discuss the Belgium and Denmark-west onshore wind results in more detail. 5 breaks down the sources of revenue (energy market and renewable subsidies) and compares them to the levelized marginal cost for onshore wind producers in Belgium and Denmark-west under an RPS policy. Both of these countries have high wind capacity factors but the onshore wind potential in Denmark-west is much higher than in Belgium. In contrast, the value of wind energy production is greater in Belgium, which is closely connected to high value markets in the Netherlands. Therefore, the onshore wind potential in Belgium is fully exploited once the 55% EU-wide renewable target is met, whereas the onshore wind potential in Denmark-west is never binding although the investments are much larger than in Belgium. As the target increases above a 55% share, the decrease in market value of onshore wind producers in Belgium is milder than the increase in their subsidy, which means that their marginal revenue (subsidy+marginal energy value) rises above their marginal cost, resulting in economic rents. In Denmark-west, in contrast, the investments in wind-onshore increases further as the target increases above a 55% share, which leads to a strong decrease in market value of onshore wind producers. In other words, the energy subsidy serves to just cover the difference between their marginal cost and market value. As renewable penetration increases, it dramatically widens gap between average electricity prices in Denmark-west (with demand-weighted price average market price decreasing from 47 €/MWh to 32 €/MWh) and revenue received by wind producers (whose average falls from 42 €/MWh to 14 €/MWh). The weighted average market prices and market values of onshore wind and solar-PV for each country are given in Appendix C.

Note that although the average price effects of different policies may appear somewhat similar, larger differences emerge if we focus on the prices in windy versus sunny hours. The energy subsidy, which favors wind investments, depresses prices more in winter, and a capacity subsidy favoring solar-PV investments depresses prices more in the summer. For instance, at a 65% renewable share, the average price in summer falls by 6 euros/MWh in Denmark-West but rises by 15 euro/MWh under the capacity subsidy relative to the energy subsidy results. Similarly, prices during summer daylight hours are lower under the capacity subsidy because of the large amount of PV generation, while prices during winter daylight hours are lower under the energy subsidy because wind output is higher than solar output in northern Europe at those times.

In general, for both capacity and energy policies, Fig. 4 shows that most of the subsidy covers the losses due to the declining value of energy produced. The portion of the RPS subsidy that is compensating for the decrease in market value increases up to 26 €/MWh (out of 33 €/MWh) for onshore wind, and 29 €/MWh (out of 33 €/MWh) for solar-PV at a 65% renewable share. Meanwhile, the contribution of the capacity subsidy increases to 14 €/MWh (out of 18 €/MWh) for onshore wind, and to 29 €/MWh (out of 45 €/MWh) for solar-PV.

The above results should be interpreted somewhat cautiously, however. Our assumption of uniform costs for solar and on-shore wind within a country will in general result in an understatement of the amount of economic rent, since in fact there is generally a diversity of resource qualities and development costs within countries. Given some within-country cost diversity, there will be some relatively inexpensive wind and/or solar-PV generators who will earn an intramarginal rent in, e.g., Denmark-west as well as other countries.

4.4. Technology choices under technology neutral vs. technology-specific targets

If all types of renewable energy compete for the same subsidies, then energy and capacity-focused subsidies lead to markedly different types and locations of renewable investments. The RPS pays for the production that contributes directly to a MWh target and supports technologies and locations with higher renewable generation. On the other hand, capacity subsidies pay for investments that contribute directly to a MW target, thus supporting technologies and locations with lower investment costs.

The EU and its member states in general aim for certain share of renewables in their generation (energy) mix; however they are also interested in reduction of the costs through learning-by-doing. Although energy subsidies such as the RPS are the most cost-effective way of achieving a renewable share target, EU can also implement capacity subsidies to achieve its renewable energy goal while benefiting from accelerating learning and technology improvement via additional capacity installations. Assuming that policy makers implement capacity subsidies to meet a 65% energy target, the capacity subsidy increases the GW of total renewable investment by 46% compared to an RPS (6) while increasing the cost of the incremental renewables by about 7 €B/yr, or over 50% (Fig. 2). Achieving the same level of renewable energy, capacity subsidies boost solar-PV installations that have lower investment costs, whereas an RPS increases onshore wind investments which have higher capacity factors. The RPS also yields a small amount of offshore investment. Finally, investments under the mixed investments/output subsidy fall between these two cases, as it has characteristics of both capacity and energy policies.

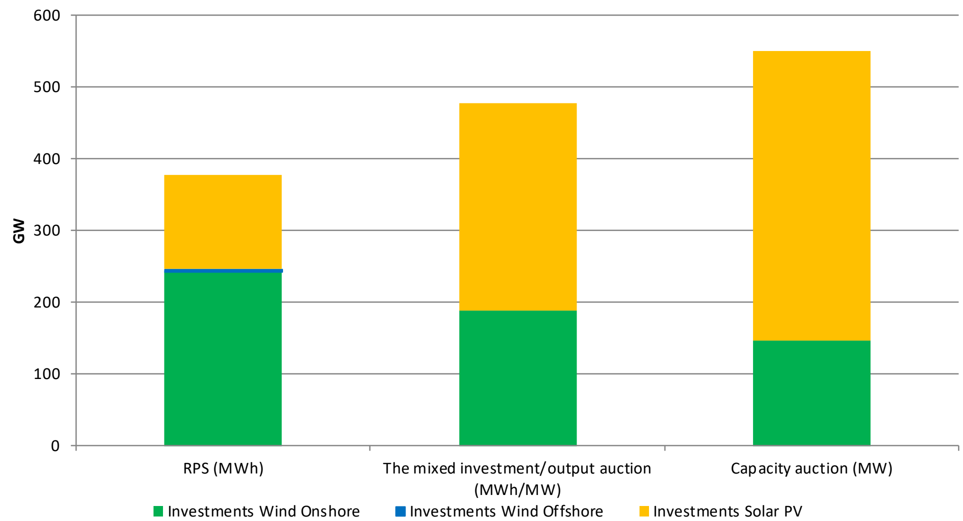


Fig. 6 Incremental investments compared to base case: wind and solar under energy and capacity-focused subsidies achieving 65% renewable share: Technology neutral case

The large differences in types of generation investments encouraged by the different policies diminish if the programs are targeted towards specific categories of investment ("carve-outs"). We now consider the impact of energy vs capacity subsidies when technology-specific targets are set; in particular, we quantify effects on cost, renewable MWh, and locational incentives for renewable investments. Technology-specific targets can make sense if the policy aim is to reduce costs through learning-by-doing, since the opportunities for such reductions will differ among technologies in part because they are at different stages of development. Ideally, one would base the capacity target on current costs and installed capacities, taking into account long-term cost-reductions resulting from both R&D and learning-by-doing, (see Fischer and Newell, 2008). However, as we shall see, creating carve-outs will diminish the cost differences between energy and capacity policies, such as those shown in Fig. 2, although the siting of new investments may still shift dramatically.

To analyze these effects, we conduct a sensitivity analysis assuming separate capacity auctions for wind and solar capacity with respective targets that equal the same GW of wind and solar investments achieved by an energy (RPS) subsidy (246 GW and 131 GW, respectively, shown in the left bar in Fig. 6). Unsurprisingly, this results in a lower total cost, saving 160 M€/yr relative to the RPS, and achieves almost the same renewable share as in the RPS case (64.6% rather than 65%). This is over an order of magnitude smaller than the over 3 B€/yr savings that results from using a single capacity auction (no separate wind and solar targets) to meet a total 377 GW (i.e., the difference between the solid dot and hollow square at 377 GW on the right side of Fig. 2).

If we now look at the locational implications (Fig. 7) of energy and capacity subsidies that achieve the same GW of wind and solar capacity, we see that capacity subsidy results in a shift of investments from locations with lower electricity prices and, therefore, lower market value of renewables (e.g., Sweden for wind and Spain for solar) to locations with higher electricity prices and market value despite the lower capacity factors of the renewable resources in these locations (e.g., Czech Republic for wind and Austria for solar). These shifts are, however, less than 10% of the total incremental investment in these technologies (left bar, Fig. 6).

In summary, most of the benefit of directing subsidies to capacity rather than energy, in terms of reducing the expense of promoting learning-by-doing by meeting a capacity target, arises from shifting investment from wind to solar, and not from shifting investment in a particular technology among different locations. Directly subsidizing 377 GW of investment without limiting the type of investment can save more than 3 B€/yr, but defining particular carve-outs for wind and solar cuts that savings by 95%, with minor savings occurring because more efficient locations are chosen.

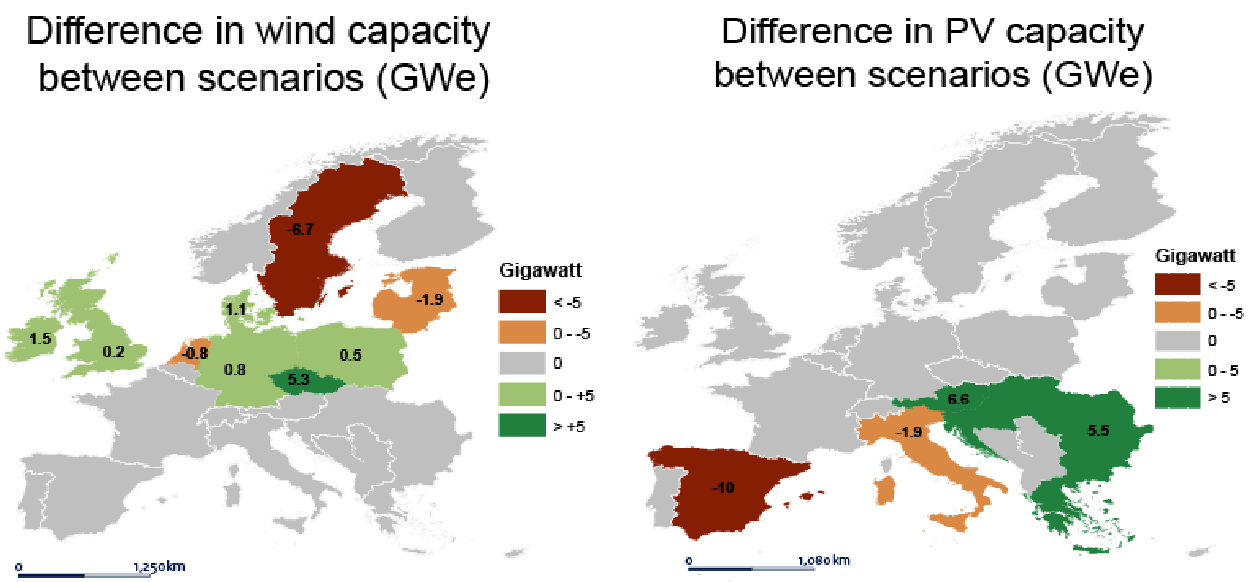


Fig. 7 The changes in installed wind capacity (left, out of 246 GW investments) and installed solar-PV capacity (right, out of 131 GW investment) when technology specific capacity subsidies are used to achieve the same GW investments as the RPS/energy subsidy with 65% renewable share target. (Note: shifts less than 0.5 GW in magnitude rounded to zero)

4.5. The inefficiencies of country-specific targets instead of an overall EU target

Implementation of country-specific targets without allowing between-country trading of renewable energy credits is inefficient and greatly increases the cost of renewable policies. For instance, Capros et al. (2011) used PRIMES to estimate the cost of meeting a 20% renewable target by 2020 in the EU with and without renewable credit trading, and found the latter to be 20.4 B€/yr more expensive. Meanwhile Newbery et al. (2013, Fig. 1) estimated an annual benefit of such trading of 15.4-30 B€/yr over the period 2015-2030.

As shown in 8, the country-specific targets in ENTSO-E's Sustainable Transition (ST) scenario achieve a 52.7% EU-wide renewable electricity share with 225 GW of new renewable capacity investments at an incremental cost of 8.5 B€/yr compared to the baseline scenario. These country targets are based on reported national plans complied by ENTSO-E. The COMPETES model estimates that this cost is about *seven* times higher than the incremental cost of achieving the same level of renewable share by an EU-wide RPS mechanism (1.2 B€/yr). Most of the cost increase of 7.3 B€/yr results from investing in renewable technologies with higher investment costs (especially offshore wind). This value is well below those of Capros et al. (2011) and Newbery et al. (2013) in large measure because of the steep decline in renewable capital costs since that time.

Moreover, the incremental cost of country-specific targets is *four* times higher than the incremental cost of achieving the same level of renewable capacity by an EU-wide capacity auction (2.0 B€/yr). In this case, EU-wide capacity auction actually achieves a higher renewable share (54%) than the national targets. Of the 8.5-2.0 = 6.5 B€/yr cost increase relative to the efficient capacity solution, three-quarters of the ENTSO-E ST's cost increase is due to investing in more expensive technologies while one-quarter due to an increase in fuel costs. Emissions are also higher in the ENSTO-E ST case.

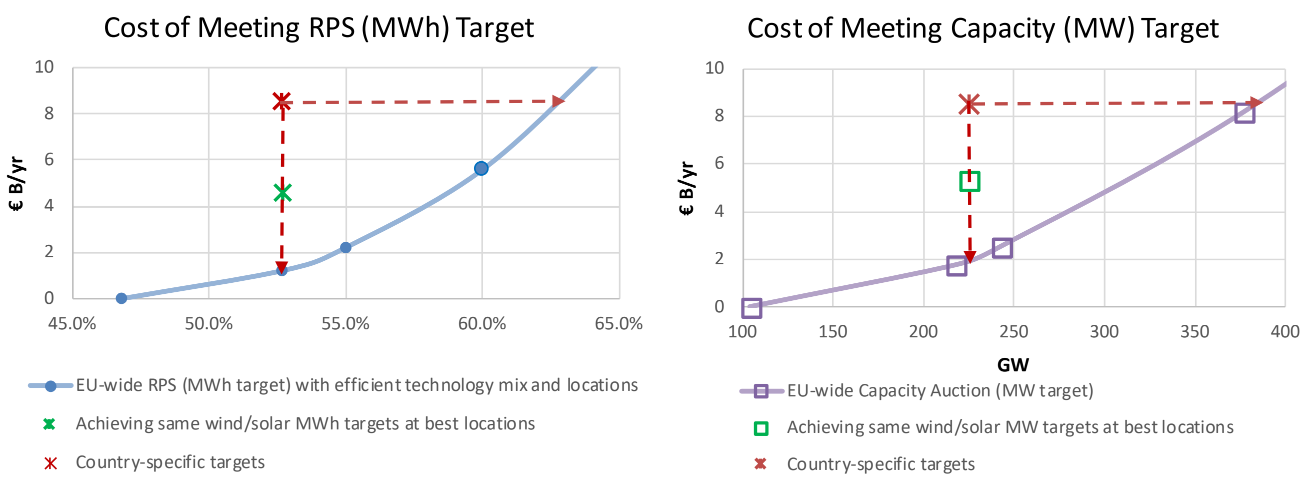


Fig. 8. The cost of inefficient technology-mix and locations resulting from country-specific targets

In order to quantify the impact of inefficient location vs inefficient technology choice on the cost increase, we simulated the RPS mechanism with EU-wide technology-specific MWh targets achieving the same shares of solar-PV (9% of total generation), onshore wind (19%), and offshore wind (7%) generation as achieved by the national targets, as assumed to be represented by the ST scenario of ENTSO-E. The incremental cost (compared to no renewable subsidies) of achieving the same technology-specific MWh targets but using the most efficient locations is 4.6 B€/yr. This is 3.4 B€/yr higher than the least cost solution for achieving 52.7% renewable energy. However, the country-specific targets (ENTSO-E ST) cost 8.5-1.2 = 7.3 B€/yr more. This indicates that about half of the inefficiency of country-specific capacity targets is due to the wrong mix of technologies, and half is due to the wrong locations.

Further, we also simulate the EU-wide capacity auction with technology-specific MW targets achieving the same capacity investments of solar-PV (113 GW), onshore wind (76.7 GW), and offshore wind (34.7 GW) as with national targets. The incremental cost of achieving the same technology specific MW targets at best locations is 5.3 € B/yr. Again, the inefficiency is roughly evenly divided between wrong mix and wrong location of technologies, with the former being responsible for about 60% of the total inefficiency.

5. Conclusions and policy implications

One of the goals of renewable energy promotion is to reap per-unit cost reductions in the long run through learning-by-doing. Capacity-based subsidies have been argued to be more effective than the prevailing approach of energy subsidies (e.g., Newbery, 2012). In this paper, we address the practical impacts on short-run (year 2030) technology adoption and costs in Europe if capacity-based auctions were to be adopted instead. We do not address longer-run impacts on learning and per-unit costs.

We use the Europe-wide electricity market model COMPETES to address these short-run impacts. Consistent with previous theoretical analyses (Meus et al., 2018), under the assumption that policy makers adjust renewable *capacity* targets to meet a 65% EU-wide *energy* target by 2030, we find that the basic capacity-based policy would increase the incremental cost of achieving that target (by 58% compared to MWh subsidies such as a feed-in premium). This is under the assumptions that all renewable technologies are eligible for the subsidy, and renewable energy credits are fully tradable across EU members. The capacity policy is more expensive because directly constraining (and paying for) the product that directly contributes to a desired target (in this case, renewable MWh) is the first-best way of meeting that target. But the capacity policy does have the benefit of increasing the GW of renewable investment compared to the no-policy case (446 additional GW, which is 63% higher than the 273 GW additional capacity in the energy target case). In contrast, the results of Newbery et al. (2018) proposal fall in-between these cases, as it has characteristics of both capacity and energy policies; compared to no policy, it increases the incremental GW capacity investment used to meet the 65% MWh target (by 36%, 372 GW vs. 273 GW under the energy policy) at a somewhat lower cost than the capacity policy (a 28% higher incremental cost than the feed-in premium policy, as opposed to a 58% increase in the case of the capacity policy).

On the other hand, if the objective is to promote technology improvement through building capacity, then a policy that directly promotes such installations may be preferred. We show, in particular, that it can be significantly less expensive (up to several billion €/yr) to use *capacity subsidy* mechanisms to achieve a given capacity installation goal than to use an approach based on renewable *energy subsidy*. On the other hand, that particular capacity policy also achieves a lower renewable penetration on an energy basis (e.g., 65% with energy subsidy vs 60% with capacity subsidy, both achieving 377 GW of renewable investments) and, therefore higher carbon emissions from the power sector that we assume are mitigated by reductions or sequestration elsewhere at the assumed carbon price.

We have also examined the costs of more aggressive renewable electricity targets, the fate of the subsidies, and the impact of technology carve-outs and renewable credit trading. If the most cost-effective technologies are adopted, the percentage of electricity provided by renewables could increase from 47% to 65% in the year 2030 at a cost of about 11B €/year using MWh subsidies. For the same $11B €/year of cost, however, Fig. 2 shows that new capacity installations could be increased from 377 GW to 430 GW by switching to capacity-based subsidies, albeit resulting in less total renewable energy (falling to about 62% of the total). Under either policy, the subsidies largely go to making up for the reduction in energy market revenues that are caused by expansion of zero marginal cost renewables; as an extreme case, average revenue received by on-shore wind in western Denmark will fall by two-thirds. This loss of revenue must be made up by subsidies if renewable development is to occur.

However, if instead energy or capacity targets were to be achieved through country- and technology-specific targets without trading renewable credits, consistent with present national targets compiled by ENTSO-E (2016a), then the costs would be several times higher (Fig. 8). Roughly half of the cost increase is due to cost-ineffective technology mixes, and the other half is due to cost-ineffective locations. Thus, a failure to implement and expand the EU Energy Directive that requires countries to allow imports to comprise up to 15% of incremental national targets in the 2026-2030 (European Commission, 2018) will potentially be very expensive for EU power consumers.

Overall, our analysis shows that there is considerable room for coordinating and improving renewable energy policies within Europe which will help reduce the total costs of realizing renewable energy production. Future research could refine these conclusions based on models that include more operational details, such as generating unit commitment; specific assumptions about the likely amounts and qualities of wind and solar resources within each country; and explicit modeling of carbon offsets and trading with non-power sectors in order to represent interactions with carbon policies. Finally, the extent of learning and resulting cost reductions that might result from investment in various technologies under alternative policies could be estimated based on learning rates from the literature (e.g., Nagy et al., 2012; Rubin et al., 2015; National Academy of Sciences, 2016).

References

Andor, M., Voss, A., 2016. Optimal renewable-energy promotion: Capacity subsidies vs. generation subsidies. Resource and Energy Economics, 45, 144-158.

Andresen, T.M., 2012. Including Learning in Cost Analyses of Renewable Energy. M.Phil. Thesis, Dept. Economics, Univ. of Oslo.

Banja, M., Scarlat, N., Monforti-Ferrario, F., Dallemand, J.F., 2013. Renewable energy progress in EU 27 (2005–2020). Report EUR 26481 EN, Joint Research Centre, Ispra, Italy.

Barquín, J., Rodilla, P.,Cossent, R., Batlle, C., 2017. Obtaining best value for money in RES auctions: a capacity-based with an embedded menu of contracts approach. Working Paper, Comillas Pontifical University, Madrid, Spain. https://repositorio.comillas.edu/jspui/handle/11531/23913

Beurskens, L., ed., 2011. Assessment of the effectiveness and economic efficiency of selected support options for the Netherlands. RES-H Policy project Report D14, ECN, Petten, The Netherlands. http://www.invert.at/Dateien/Res-H%20Policy%20D13/RES-H_Policy_D13_NL_english.pdf

Brouwer, A.S., Broek, van den M., Özdemir, Ö., Koutstaal, P., Faaij, A., 2016. Business case uncertainty of power plants in future energy systems with wind power. Energy Policy, 89, 237-256.

Cameron, L.R., van Stralen, J., Veum, K.C., 2011, Scenarios for offshore wind including spatial interactions and grid issues. WindSpeed report D6.1, ECN-O-11-066, ECN, Petten, The Netherlands. https://www.ecn.nl/publicaties/ECN-O-11-066

Capros, P., De Vita, A., Tasios, N., Papadopoulos, D., Siskos, P., Apostolaki, E., Zampara, M., Paroussos, L., Fragiadakis, K., Kouvaritakis, N., et al., 2013. EU Energy, Transport and GHG Emissions: trends to 2050, reference scenario 2013. European Comission, 16 December 2013.

Capros, P., Mantzos, L., Parousos, L., Tasios, N., Klaassen, G. and Van Ierland, T., 2011. “Analysis of the EU policy package on climate change and renewables.” Energy policy, 39(3), pp.1476-1485Del Río, P., 2017. Why does the combination of the European Union Emissions Trading Scheme and a renewable energy target makes economic sense? Renewable and Sustainable Energy Reviews, 74, 824–834.

Del Río, P., Resch, G., Ortner, A. Liebmann, L., Busch, S., Panzer, C., 2017. A techno-economic analysis of EU renewable electricity policy pathways in 2030. Energy Policy, 104, 484–493.

Daniëls, B.W., Uyterlinde, M.A., 2005. ADMIRE-REBUS: modeling the European market for renewable electricity. Energy, 30, 2596-2616. https://www.sciencedirect.com/science/article/pii/S0360544204003093

Dirkse, S.P., Ferris, M.C., 1995. The PATH solver: a non-monotone stabilization scheme for mixed complementarity problems. Optimiz. Meth. Software, 5(2), 123–156.

ENTSO-E, 2016a. TYNDP 2016 Scenario development report-final after public consultation. ENTSO-E, Brussels, Belgium.

ENTSO-E, 2016b. Mid-Term adequacy forecast. ENTSO-E, Brussels, Belgium. https://www.entsoe.eu/outlooks/midterm/

ENTSO-E, 2018. TYNDP 2018 – Scenario report. ENTSO-E, Brussels, Belgium. http://tyndp.entsoe.eu/tyndp2018/scenario-report/

European Commission, 2018. Europe leads the global clean energy transition: Commission welcomes ambitious agreement on further renewable energy development in the EU, http://europa.eu/rapid/press-release_STATEMENT-18-4155_en.htm.

Fischer, C., 2010. Renewable portfolio standards: when do they lower energy prices? Energy Journal, 31(1), 101-119.

Fischer, C., Newell, R.G., 2008. Environmental and technology policies for climate mitigation. Journal of Environmental Economics and Management, 55(2), 142-162.

Gabriel, S.A., Conejo, A.J., Fuller, J.D., Hobbs, B.F., Ruiz, C., 2012. Complementarity Modeling in Energy Markets. Springer, New York.

Gerarden, T., 2017. Demanding innovation: The impact of consumer subsidies on solar panel production costs, Working Paper, Harvard University.

Gorm, B.A., Søndergaard, A.A., Greiner, M., 2015. Validation of Danish wind time series from a new global renewable energy atlas for energy system analysis. Energy Journal, 93, 1074-1088.

Green, R.J., Pudjianto, D., Staffell, I., Strbac, G., 2016. Market design for long-distance trade in renewable electricity. Energy Journal, 37(Special Issue), 5-22.

Hallstead, M., 2013, A scenario analysis of PV deployment in Europe up to 2050. MSc thesis, Vrije Universiteit Amsterdam, the Netherlands.

Hartigan, J. A., 1975. Clustering Algorithms. New York, NY, USA: Wiley.Huntington.

Huntington, S.C., Rodilla, P., Herrero, I., Batlle, C., 2017. Revisiting support policies for RES-E adulthood: towards market compatible schemes. Energy Policy, 104, 474–483.

Hytowitz, R.B., 2018. Optimization modeling to address the impacts of electric power market design on operations and policy. Ph.D. Dissertation, The Johns Hopkins University, Baltimore, USA.

IEA, 2016. World Energy Outlook 2016. International Energy Agency OECD/IEA, Paris, France.

Kreiss, J., Ehrhart, K.-M., Haufe, M.-C., Rosenlund Soysal, E., 2017. Different cost perspectives for renewable energy support: assessment of technology-neutral and discriminatory auctions. Working paper, Karlsruhe Institute of Technology.

Koutstaal, P., Bijlsma, M., Zwart, G., van Tilburg, X., Özdemir, Ö., 2009. Market performance and distributional effects on renewable energy markets. CPB Document 190, CPB Netherlands Bureau for Economic Policy Analysis, Den Haag, The Netherlands.

Meus, J., van den Bergh, K., Delarue, E., Proost, S., 2018. On international renewable cooperation mechanisms: the impact of national RES-E support schemes, Working Paper, KU Leuven.

Nagy, B., Farmer, J.D., Bui, Q.M., Trancik, J.C., 2012. Predicting technological progress. Proc. National Acad. Sciences.

Nahmmacher, P., Schmid, E., Hirth, L., Knopf, B., 2016. Carpe Diem: A novel approach to select representative days for long-term power system modelling. Energy, 112, 430-442.

National Academy of Sciences, 2016. Electricity from Renewable Resources: Status, Prospects, and Impediments, Washington, DC.

Neuhoff, K., May, N., Richstein, J., 2017. Incentives for the long-term integration of renewable energies: a plea for a market value model. DIW Economic Bulletin *7*(46/47), 467-476.

Neuhoff, K., Wolter, S., Schwenen, S., 2016. Power markets with renewables: new perspectives for the European target model. Energy Journal, 37(Special Issue), 23-38.

Newbery, D., 2012. Reforming competitive electricity markets to meet environmental targets: Economics of energy & environmental policy, 1(1), 69-82.

Newbery, D., 2018. Evaluating the case for supporting renewable electricity, Energy Policy, 120, 684–696. https://doi.org/10.1016/j.enpol.2018.05.029

Newbery, D., Pollitt, M.G., Ritz, R.A., Strielkowski, W., 2018. Market design for a high-renewables European electricity system. Renewable and Sustainable Energy Reviews, 91, 695-707.

Newbery, D.M., Strbac G., Pudjianto D., Noël P., Booz & Co. and LeighFisher, 2013. Benefits Of An Integrated European Energy Market Final report for DG ENER, July at http://ec.europa.eu/energy/infrastructure/studies/doc/20130902_energy_integration_benefits.pdf

Özdemir, Ö., Munoz, F.D., Ho, J., Hobbs, B.F., 2016. Economic analysis of transmission with demand response and quadratic losses by successive LP. IEEE Transactions on Power Systems, 31(2), 1096-1107.

Özdemir, Ö. , de Joode, J., Koutstaal, P., van Hout, M., 2013. Financing investment in new electricity generation capacity: the impact of a German capacity market on northwest Europe. Proceedings, 10th International Conference on the European Energy Market, Stockholm, Sweden.

Özdemir, Ö., van Hout, M., Koutstaal, P., 2014. Value of flexibility for balancing wind power generation. Proceedings, 14th IAEE European Energy Conference, Rome, Italy.

Özdemir, Ö., van Hout, M., Koutstaal, P., 2017. Integration costs and market value of variable renewables: a study for the Dutch power market. ECN-W-17-035, Petten, The Netherlands.

Perez, A.P., Sauma, E.E., Munoz, F.D., Hobbs, B.F., 2016. The economic effects of interregional trading of renewable energy certificates in the WECC. Energy Journal, 37(4), 267-296.

Resch, G., ed., 2017. Dialogue on a RES policy framework for 2030-Towards 2030-dialogue. TU Wien, Vienna. http://towards2030.eu/sites/default/files/Towards2030-dialogue%20Final%20Report.pdf

Richstein, J.C., Chappin, E.J.L., de Vries, L.J., 2015. Adjusting the CO_2 cap to subsidised RES generation: can CO_2 prices be decoupled from renewable policy? Applied Energy, 156, 693–702.

Rubin, E.S., Axevedo, I.M.L., Jaramillo, P., Yeh, S., 2015. A review of learning rates for electricity supply technologies. Energy Policy, 86, 298-218.

Schoots, K., Hekkenberg, M., Hammingh, P., 2017. Nationale energieverkenning 2017. ECN-O-17-018. ECN, Petten, The Netherlands.

Siler-Evans, K., Azevedo, I.L., Morgan, M.G., Apt, J., 2013. Regional variations in the health, environmental, and climate benefits of wind and solar generation. Proceedings of the National Academy of Sciences, 110(29), 11768-11773.

Sijm, J., van Hout, M., Özdemir, Ö, van Stralen, J., Smekens, K., van der Welle, A., van Werner, W., Musterd, M., 2017. The supply of flexibility for the power system in the Netherlands (2015-2050). ECN-E-17-044, ECN, Petten, The Netherlands.

Steinhilber, S., 2016. Onshore wind concession auctions in China: instruments and lessons learnt. AURES Report D4.1-CN, March. http://auresproject.eu/files/media/countryreports/pdf_china.pdf

Tanaka, M., Chen, Y., 2013. Market power in renewable portfolio standards. Energy Economics, 39, 187-196.

Unteutsch, M., 2014. Redistribution effects resulting from cross-border cooperation in support for renewable energy. EWI Working Paper, No. 14/01, University of Cologne, Cologne, Germany.

van Benthem, A., Gillingham, K., Sweeney, J., 2008. Learning-by-Doing and the Optimal Solar Policy in California, Energy Journal, 29, 131-151

Van Hout, M., Koutstaal, P., Özdemir, Ö., Seebregts, A., 2014. Quantifying flexibility markets. ECN-E–14-039, ECN, Petten, The Netherlands.

Van Hout, M., Özdemir, Ö., Koutstaal, P., 2017. Large-Scale balancing with Norwegian hydro power in the future European electricity market. ECN-E-17-043, ECN, Petten, The Netherlands.

Wind Europe, 2017. Wind energy in Europe: scenarios for 2030, Wind Europe, Brussels, Belgium. https://windeurope.org/about-wind/reports/wind-energy-scenarios-2030/

Appendix A: Derivation of annualized revenue and market clearing constraint for mixed investment/output subsidy policy

In this Appendix, we first derive an equivalent annualized revenue expression for the mixed auction described by Steinhilder (2016)/Newbery et al. (2018) in which an auction is held for MWh, but no more than a predetermined number B of MWh per MW of capacity from a given facility will receive a subsidy (B's units are therefore in total hours). We assume further that the subsidy will be paid at the end of the year in which qualifying MWh are generated, and will not be paid to a given facility for more than a predetermined number of years T. We then consider the simulation of the market impact of this subsidy using the linear programming market model COMPETES.

Consider a renewable generator of type r at location i with lifetime T_{ir} that can produce the target B number of MWh prior to the last year of eligibility or last year of its operation (whichever is less). We then define M_{ir} satisfying $M_{ir} + 1 \leq \text{MIN}(T, T_{ir})$ years such that $FLH_{ir} * M_{ir} + RFLH_{ir} = B$ (FLH_{ir} is the full load hours for the generator; i.e., it is in units of MWh/MW. $RFLH_{ir}$ is the remaining full load hours that can receive subsidies after year M_{ir}). Then this generator will earn the per MWh price, γ^*, for B MWh of renewable generation distributed over $M_{ir} + 1$ years. The present value of the revenue from this subsidy for a plant owned by company *n* if it has capacity y_{nir} is:

$$NPVS_{nir} = \gamma^* y_{nir} \left(\sum_{t=1}^{M_{ir}} \left(\frac{FLH_{ir}}{(1 + INT)^t} \right) + \frac{RFLH_{ir}}{(1 + INT)^{M_{ir}+1}} \right)$$

where INT is the relevant interest rate. Note that we are assuming that there is no curtailment of renewable output by the system operator (or due to low prices). This is equivalent to the regulators paying for potential output when system conditions require curtailment, which elsewhere we argue is a policy that promotes more efficient system operation due to the deleterious effects on system cost and even emissions when negative bidding is incented (Deng et al., 2015). If a policy in which only MWh actually produced is to be simulated, more complex versions of the formulas in this Appendix can be derived.

On the other hand, if the generator's capacity factor is sufficiently low such that it cannot produce the target B prior to the last year of eligibility or its retirement year (i.e., $FLH_{ir} * \text{MIN}(T, T_{ir}) < B$), then it will receive revenue for less than B MWh over its lifetime. The above present value expression is then simplified to:

$$NPVS_{nir} = \gamma^* y_{nir} \sum_{t=1}^{\text{MIN}(T, T_{ir})} \left(\frac{FLH_{ir}}{(1 + INT)^{t}} \right)$$

Then by multiplying this present value (in €) by the appropriate annualization factor (A|P,INT, T_{ir}) = $INT * (1 + INT)^{T_{ir}} / ((1 + INT)^{T_{ir}} - 1)$ (in 1/yr) (given the interest rate and asset lifetime) provides the equivalent annual revenue subsidy in €/yr:

$$NPVS_{nir} * (\text{A}|\text{P}, \text{INT}, T_{ir}) = \gamma^* y_{nir} \underbrace{\left(\sum_{t=1}^{M_{ir}} \left(\frac{FLH_{ir}}{(1+INT)^t} \right) + \frac{RFLH_{ir}}{(1+INT)^{M_{ir}+1}} \right) * \frac{INT * (1+INT)^{T_{ir}}}{((1+INT)^{T_{ir}} - 1)}}_{EFLH_{ir}} \equiv \gamma^* y_{nir}\, EFLH_{ir}$$

where $EFLH_{ir}$ is defined as the equivalent full load hours per year for that generator. This term is summed over all new renewable generators owned by the company and included in its annualized profit objective (6).

Now consider the simulation of this auction in the LP formulation of the market model. Assume that a subsidy of γ^* €/MWh is announced to all comers which is paid out according the rules in the first paragraph of this Appendix. If the company n's annualized profit objective is given by (6), and if the company builds y_{nir} MW of renewable generation capacity, then it will view that subsidy as contributing $\gamma^* y_{nir} EFLH_{ir}$ to its annualized profit (6) in its solution. The marginal subsidy term $\gamma^* EFLH_{ir}$ will appear in its first-order condition for its variable y_{nir} in its profit maximization problem (in Section 3.1.1). This is complementarity condition (38) in Appendix B.

Now consider a LP formulation of the entire market (as in Section 3.2) in which the market clearing condition is imposed: $\sum_{n,i,r} EFLH_{ir} y_{nir} \leq \bar{V}$. The units of both sides are MWh/yr. This constraint will have a shadow price, say γ^* €/MWh. In the first-order conditions of the LP, this market clearing condition will result in including a term $\gamma^* EFLH_{ir}$ as a "benefit" in the first-order condition for variable y_{nir}, consistent with the profit maximizing condition for the company. This is identical to the first-order condition we just discussed for a profit-maximizing firm subject to such a policy (condition (38), below). Thus, including this market clearing constraint simulates the incentive provided to renewable generators by a mixed investment/output subsidy policy in which a €/MWh subsidy is paid consistent with the rules we have assumed.

Appendix B: KKT conditions

In Section 3.1, the optimization problem of each market player operating in an energy-only market or one of three alternative market-based renewable support schemes is convex (concave objective subject to convex feasible region). Therefore, the solution to each player's problem is equivalent to solving its KKT conditions. In this Appendix, we will derive the set of KKT conditions for the generators and TSO as an illustration.

The KKT conditions for each firm n in an energy-only market:

$$0 \le -p_{ih}^{*} + MC_{ik} + \mu_{nikh} \quad \perp \quad g_{nikh} \ge 0 \quad \forall n \in N, i \in I_n, k \in K_n, h \in H, \tag{26}$$

$$0 \le \alpha_{ikh}(Y_{nik}^{0} + y_{nik}) - g_{nikh} \quad \perp \quad \mu_{nikh} \ge 0 \quad \forall n \in N, i \in I_n, k \in K_n, h \in H. \tag{27}$$

$$0 \le -\sum_h NH_h \alpha_{ikh} \mu_{nikh} + AIC_{ik} \quad \perp \quad y_{nik} \ge 0 \quad \forall n \in N, i \in I_n, k \in K_n, \tag{28}$$

where $\mu_{nikh} * NH_h$ is the €/yr dual variable (e.g., shadow price) of the generator's maximum capacity constraint (2). The economic interpretation of (26) and (27) is that firm n with generator type k operating in hour h earns a positive (scarcity or capacity) rent μ_{nikh} in that hour when it produces at maximum capacity. This rent is equal to the difference between the electricity price p_{ih}^{*} in that hour and the generator's marginal cost MC_{ik}. The economic interpretation of (28) is that firm n invests in generator type k when the annualized weighted sum of the scarcity rents over all hours is equal to the annualized investment cost AIC_{ik}.

The KKT conditions for each firm n in an electricity market with energy-based renewable policy:

In an electricity market with energy-based renewable policy, firm n with renewable generator r operating in hour h receives energy subsidy λ^{*} in addition to the electricity price p_{ih}^{*}. Therefore, (29) implies that the capacity rent of the renewable generator r is equal to the difference between its marginal revenue $(\lambda^{*} + p_{ih}^{*})$ in that hour and the generator's fuel cost MC_{ik}. The KKT conditions for the nonrenewable generators of firm n $(k \in (K_n - R_n))$ is the same as in the energy-only market case.

$$0 \le -\lambda^{*} - p_{ih}^{*} + MC_{ir} + \mu_{nirh} \quad \perp \quad g_{nirh} \ge 0 \quad \forall n \in N, i \in I_n, r \in R_n, h \in H, \tag{29}$$

$$0 \le -p_{ih}^{*} + MC_{ik} + \mu_{nikh} \quad \perp \quad g_{nikh} \ge 0 \quad \forall n \in N, i \in I_n, k \in K_n - R_n, h \in H, \tag{30}$$

$$0 \le -\sum_h NH_h \alpha_{ikh} \mu_{nikh} + AIC_{ik} \quad \perp \quad y_{nik} \ge 0 \quad \forall n \in N, i \in I_n, k \in K_n, \tag{31}$$

$$0 \le \alpha_{ikh}(Y_{nik}^{0} + y_{nik}) - g_{nikh} \quad \perp \quad \mu_{nikh} \ge 0 \quad \forall n \in N, i \in I_n, k \in K_n, h \in H. \tag{32}$$

The KKT conditions for each firm* n *in an electricity market with renewable capacity auction:

In an electricity market with capacity auction, firm n receives annualized capacity payment β^{*} per MW renewable capacity r. The KKT condition (34) implies that firm n invests in renewable generator type r when the sum of this capacity payment and the weighted sum of the scarcity rents over all hours in a year covers its annualized investment cost AIC_{ir}. The KKT conditions for the nonrenewable generators of firm n $(k \in (K_n - R_n))$ is the same as in the energy-only market case.

$$0 \le -p_{ih}^{*} + MC_{ik} + \mu_{nikh} \quad \perp \quad g_{nikh} \ge 0 \quad \forall n \in N, i \in I_n, k \in K_n, h \in H, \tag{33}$$

$$0 \le -\beta^* - \sum_h NH_h \alpha_{irh} \mu_{nirh} + AIC_{ir} \quad \perp \quad y_{nir} \ge 0 \qquad \forall n \in N, i \in I_n, r \in R_n, \tag{34}$$

$$0 \le -\sum_h NH_h \alpha_{ikh} \mu_{nikh} + AIC_{ik} \quad \perp \quad y_{nik} \ge 0 \qquad \forall n \in N, i \in I_n, k \in K_n - R_n, \tag{35}$$

$$0 \le \alpha_{ikh}(Y^0_{nik} + y_{nik}) - g_{nikh} \quad \perp \quad \mu_{nikh} \ge 0 \qquad \forall n \in N, i \in I_n, k \in K_n, h \in H. \tag{36}$$

The KKT conditions for each firm n in an electricity market with mixed investment/output subsidy:

The difference between capacity auction and the mixed auction is the annualized capacity subsidy which is equal to $\gamma^* EFLH_{ir}$ for renewable generator type r contributing to its annualized profit. The KKT condition (38) implies that firm n invests in renewable generator type r when the sum of this capacity payment and the weighted sum of the scarcity rents over all hours in a year covers its annualized investment cost AIC_{ir}. The KKT conditions for the nonrenewable generators of firm n ($k \in (K_n - R_n)$) is the same as in the energy-only market case.

$$0 \le -p^*_{ih} + MC_{ik} + \mu_{nikh} \quad \perp \quad g_{nikh} \ge 0 \qquad \forall n \in N, i \in I_n, k \in K_n, h \in H, \tag{37}$$

$$0 \le -\gamma^* EFLH_{ir} - \sum_h NH_h \alpha_{irh} \mu_{nirh} + AIC_{ir} \quad \perp \quad y_{nir} \ge 0 \qquad \forall n \in N, i \in I_n, r \in R_n, \tag{38}$$

$$0 \le -\sum_h NH_h \alpha_{ikh} \mu_{nikh} + AIC_{ik} \quad \perp \quad y_{nik} \ge 0 \qquad \forall n \in N, i \in I_n, k \in K_n - R_n, \tag{39}$$

$$0 \le \alpha_{ikh}(Y^0_{nik} + y_{nik}) - g_{nikh} \quad \perp \quad \mu_{nikh} \ge 0 \qquad \forall n \in N, i \in I_n, k \in K_n, h \in H. \tag{40}$$

The KKT conditions for TSO:

$$0 = -p^*_{ih} - \theta_{ih} + \rho_h \quad \perp \quad a_{ih}\ free \qquad \forall\ i \in I, h \in H \tag{41}$$

$$0 \le \sum_i \Phi_{il} \theta_{ih} + \overline{\varepsilon_{lh}} \quad \perp \quad \overline{f_{lh}} \ge 0 \qquad \forall\ l \in I, h \in H \tag{42}$$

$$0 \le -\sum_i \Phi_{il} \theta_{ih} + \underline{\varepsilon_{lh}} \quad \perp \quad \underline{f_{lh}} \ge 0 \qquad \forall\ l \in I, h \in H \tag{43}$$

$$0 = \sum_l \Phi_{il} (\overline{f_{lh}} - \underline{f_{lh}}) - a_{ih} \quad \perp \quad \theta_{ih}\ free \qquad \forall\ i \in I, h \in H \tag{44}$$

$$0 = \sum_i a_{ih} \quad \perp \quad \rho_h \quad free \qquad \forall\ h \in H \tag{45}$$

$$0 \le NTC_l - \overline{f_{lh}} \quad \perp \quad \overline{\varepsilon_{lh}} \ge 0 \qquad \forall\ l \in L, h \in H \tag{46}$$

$$0 \le NTC_l - \underline{f_{lh}} \quad \perp \quad \underline{\varepsilon_{lh}} \ge 0 \qquad \forall\ l \in L, h \in H \tag{47}$$

Appendix C: 2030 Simulation results per country

Table C-1. Wind Capacity Investments (GW), subsidies and total incremental generation costs (€B/yr) under EU-wide energy vs capacity-focused policies

EU-27 member states (excl. Malta)	Wind Capacity 2020 (GW)	New Wind Capacity Investments (GW) in 2030									
		Baseline	RPS achieving % RES shares				Capacity Subsidy achieving % RES shares			The mixed investment/output subsidy achieving % RES shares	
		47%	*53%*	*55%*	*60%*	*65%*	*55%*	*60%*	*65%*	*55%*	*65%*
BEL	5	0	0	0	1	1	0	1	1	0	1
CZE	1	0	0	0	0	6	0	0	0	0	1
DEN	2	0	0	0	0	1	0	0	0	0	1
DEW	5	0	0	2	3	4	1	3	2	1	4
FIN	3	4	5	5	5	5	5	5	5	5	5
FRA	15	28	38	42	58	58	35	35	35	35	40
GER	61	0	5	5	5	5	5	5	5	5	5
IRE	5	1	2	2	3	4	2	2	3	2	4
ITA	12	0	4	4	4	4	4	4	4	4	4
NED	6	0	3	3	3	6	3	3	3	3	3
POL	7	0	0	0	8	22	0	2	7	0	19
POR	5	0	6	8	11	11	1	0	0	4	2
SKO	0	0	0	2	2	2	2	2	2	2	2
SPA	28	25	25	25	25	25	25	25	25	25	25
SWE	9	3	11	13	23	34	10	14	14	11	21
UKI	22	20	29	30	36	43	28	30	32	30	41
BLT	1	0	0	1	2	6	1	1	2	1	3
AUS	4	3	3	3	3	3	3	3	3	3	3
BLKEU	9	0	1	5	5	5	5	5	5	5	5
Total (GW)	198	86	133	151	197	246	131	142	147	138	189
Total subsidy payment for new wind units (€B/yr)	-	0	4.0	7.5	14	26.8	4.0	6.7	8.4	4.5	13.4
Total Incremental Generation cost [3] (€B/yr)	-	0	1.2	2.2	5.6	11.1	2.5	8.2	17.4	2.3	14.1

[3] Includes investment costs (as well as savings from retirements) and variable generation costs of conventional units, storage and renewables, as well as costs of load shedding. NB: no load shedding was observed in any of the cases. Furthermore, import costs from non-EU countries are included as well, with import prices adjusted for border congestion, assuming that congestion revenues are equally shared between neighboring countries.

Table C-2. Solar-PV Capacity Investments (GW subsidies and total increamental generation costs (€B/yr) under EU-wide energy vs capacity-focused policies

EU-27 member states (excl. Malta)	Solar-PV Capacity 2020 (MW)	New Solar-PV Capacity Investments (MW) in 2030									
		Baseline	**RPS achieving % RES shares**				**Capacity Subsidy achieving % RES shares**			**The mixed investment/output subsidy achieving % RES shares**	
		47%	*53%*	*55%*	*60%*	*65%*	*55%*	*60%*	*65%*	*55%*	*65%*
BEL	4	0	0	0	0	0	0	4	13	0	9
CZE	3	0	0	0	0	0	0	0	2	0	0
DEN	0	0	0	0	0	0	0	0	0	0	0
DEW	1	0	0	0	0	0	0	0	0	0	0
FIN	0	0	0	0	0	0	0	0	0	0	0
FRA	9	0	0	0	0	0	3	22	54	0	36
GER	47	0	0	0	0	0	0	13	68	0	0
IRE	0	0	0	0	0	0	0	5	8	0	2
ITA	20	0	19	34	52	66	55	71	85	52	92
NED	6	0	0	0	0	0	0	0	0	0	0
POL	0	0	0	0	0	0	0	0	19	0	0
POR	1	0	0	0	0	0	2	5	6	1	6
SKO	1	0	0	0	0	0	0	0	0	0	0
SPA	8	18	30	33	39	52	47	56	64	44	68
SWE	0	0	0	0	0	0	0	0	0	0	0
UKI	14	0	0	0	0	0	0	0	3	0	0
BLT	0	0	0	0	0	0	0	0	0	0	0
AUS	2	0	0	0	0	13	5	30	35	0	32
BLKEU	7	0	0	0	0	0	0	30	47	0	43
Total (GW)	122	18	49	67	91	131	112	236	403	97	287
Total subsidy payment for new solar-PV units (€B/yr)	-	0	0.7	1.3	3.1	6.9	3.4	11.2	23.1	2.7	16.5
Total Incremental Generation cost (€B/yr)	-	0	1.2	2.2	5.6	11.1	2.5	8.2	17.4	2.3	14.1

Table C-3. Weighted Average electricity prices under EU-wide energy vs capacity-focused policies

	Weighted average electricity prices (€2010/MWh)									
	Baseline	RPS achieving % RES shares				Capacity Subsidy achieving % RES shares			The mixed investment/output subsidy achieving % RES shares	
EU-27 member states (excl. Malta)	*47%*	*53%*	*55%*	*60%*	*65%*	*55%*	*60%*	*65%*	*55%*	*65%*
BEL	50	47	46	44	40	46	42	38	46	40
CZE	48	47	46	44	38	45	41	38	45	39
DEN	49	46	44	39	32	45	39	35	44	35
DEW	47	45	44	39	32	44	39	35	44	35
FIN	39	32	30	23	21	32	28	25	32	22
FRA	42	35	32	25	21	34	28	25	34	23
GER	48	46	45	43	39	45	40	36	45	38
IRE	48	43	41	35	27	43	38	35	42	33
ITA	51	49	47	44	41	45	40	37	45	36
NED	50	47	46	44	40	46	42	38	46	40
POL	48	47	46	43	35	46	42	38	46	37
POR	45	36	33	25	19	36	29	27	35	23
SKO	47	46	43	42	37	43	38	35	43	35
SPA	43	36	33	26	20	34	28	25	34	22
SWE	40	33	30	21	14	33	28	25	32	21
UKI	49	44	42	36	29	44	41	38	43	35
BLT	46	42	38	30	20	39	34	30	39	26
AUS	48	47	45	43	38	44	37	34	44	35
BLKEU	49	48	46	45	42	46	39	36	46	36
Average EU energy price (€/MWh)	46	43	41	37	32	41	36	33	41	32

Table C-4. Energy market value (revenue) of onshore wind under EU-wide energy vs capacity-focused policies

EU-27 member states (excl. Malta)	LRMC €2010/MWh	Market Value Onshore wind (€2010/MWh)							
		Baseline	RPS achieving % RES shares				Capacity Subsidy achieving % RES shares		
		47%	*53%*	*55%*	*60%*	*65%*	*55%*	*60%*	*65%*
BEL	52	44	40	39	37	32	40	36	33
CZE	67	47	45	42	40	34	43	38	36
DEN	47	44	38	35	26	14	37	31	28
DEW	47	42	38	35	26	14	37	31	28
FIN	39	39	31	29	22	19	32	27	25
FRA	37	37	29	25	18	15	29	24	21
GER	45	44	40	39	37	33	39	35	32
IRE	37	37	28	25	16	4	29	25	22
ITA	57	51	48	47	44	40	45	41	39
NED	44	44	40	38	36	31	39	35	32
POL	58	46	44	42	37	25	42	38	34
POR	41	41	32	29	20	14	33	27	24
SKO	54	47	45	43	41	35	43	38	35
SPA	38	39	32	29	22	16	30	25	23
SWE	40	40	32	28	19	7	32	27	24
UKI	42	42	34	31	22	9	34	29	27
BLT	49	45	40	37	28	16	39	33	29
AUS	46	47	46	43	41	37	43	37	35
BLKEU	57	49	48	46	45	43	45	40	38
Energy Subsidy (€2010/MWh)		0	9	12	21	33	-	-	-
Capacity Subsidy (€2010/MW)		0	-	-	-	-	30204	47614	57345

Table C-5. Energy market value (revenue) of solar-PV under EU-wide energy vs capacity-focused policies

		Market Value Solar-PV (€2010/MWh)							
		Baseline	RPS achieving % RES shares				Capacity Subsidy achieving % RES shares		
EU-27 member states (excl. Malta)	**LRMC €2010/MWh**	***47%***	***53%***	***55%***	***60%***	***65%***	***55%***	***60%***	***65%***
BEL	83	46	44	43	40	36	42	34	24
CZE	87	44	42	41	39	33	39	31	25
DEN	92	44	43	41	37	32	40	31	22
DEW	91	44	42	41	37	32	39	31	20
FIN	97	29	25	23	15	22	25	22	14
FRA	52	41	35	32	24	18	31	19	12
GER	84	44	42	41	38	33	39	31	20
IRE	87	49	47	46	42	37	46	36	25
ITA	54	49	45	42	33	21	34	22	16
NED	94	45	43	42	39	34	41	33	23
POL	92	44	43	42	39	34	40	36	27
POR	48	44	34	31	22	15	30	20	14
SKO	83	44	42	40	38	33	39	29	24
SPA	41	41	32	29	20	8	24	15	10
SWE	97	28	24	23	14	19	24	21	14
UKI	100	46	43	42	38	33	43	38	34
BLT	96	41	37	34	28	21	33	29	23
AUS	66	45	43	41	38	33	39	24	16
BLKEU	71	47	45	44	42	38	43	30	22
Energy Subsidy (€2010/MWh)		0	9	12	21	33	-	-	-
Capacity Subsidy (€2010/MW)		0	-	-	-	-	30204	47614	57345