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Capacity vs energy subsidies for promoting renewable investment: Benefits and costs for the EU power market

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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, reducing CO_2-emissions and promoting technology improvement through learning-by-doing. Using a detailed country-level model of generation markets, 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 and how they interact with other policies such as the EU ETS. Our analysis shows that subsidies of energy output are cost-effective for achieving renewable energy targets in the short run, whereas policies tied to capacity installation yield more investment and might be more effective in reducing technology costs in the longer term. The difference in costs between these two policy options diminish with higher CO_2-prices. Although the differences are significant, they are smaller than cost impacts of other renewable policy design features, namely the effect of not allowing EU members to meet their individual targets by trading renewable credits with other member states.

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 value maximizing renewable production without considering the economic value of energy for meeting load, managing congestion, or reducing emissions. Therefore, the EU is moving towards feed-in premiums, curtailment requirements, and other policies in order to better align renewable investment profitability with the market value of electricity. These policies may therefore encourage development at locations where installations produce fewer annual MWh, but whose energy market value more than makes up for decreased production, due to timing or transmission availability. This supports minimizing the net economic cost of achieving renewable energy targets, at least in the short-term.

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 (National Academy of Sciences, 2016; Newbery, 2018), although estimates of the magnitude of learning differ among studies even for the same technology (Andor and Voss, 2016; Nagy et al., 2013; Rubin et al., 2015). Some authors have quantified learning externalities 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 for promoting technology improvement. In particular, if learning-by-doing depends on cumulative MW *investment* rather than MWh *production*, then policies promoting capacity installation rather than energy output might more effectively reduce technology costs (Newbery, 2012; Andor and Voss, 2016; Barquín 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 increasing energy penetration and reducing external environmental costs, at least in the short run (Meus et al., 2018).

The simplest capacity-focused policies would be per MW investment

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subsidies, such as auctions or investment tax credits. A more sophisticated variant, promoted by Newbery et al. (2018) (based on auctions 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 can benefit by receiving more subsidies 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 (net costs equal capital costs minus electricity market revenues) and a capacity factor of 30%, while Site 2 costs 125,000 €/MW/yr and has 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/yr of renewable energy would result in Site 2 being selected, 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, 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 42.8 M€/yr (=428.1*100,000). So, if the policy goal is to maximize installation to promote learning, then the capacity policy does so more cheaply (savings = 10.7 M€/yr = 53.5–42.8).

Continuing with the simple example, let's instead assume that the government has an implicit renewable energy goal of 1,500,000 MWh/yr, but uses capacity mechanisms 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, costing 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 yields 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.

Meanwhile, the mixed investment/output subsidy policy's outcome in this simple example depends on that policy's ceiling on MWh/MW subsidies and the number of years that the subsidies would be paid, as well as the interest rate. Say that interest is 5%/yr; subsidies are paid at the end of the year in which production occurs; investments last 20 years 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). 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 (received for producing 61,320 MWh/MW over 17 years). Thus, in this case, Site 1 would win the mixed capacity/energy auction. But if the auction's maximum payout is 64,824 MWh/MW and interest equals 10%/yr, Site 2 becomes 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 precise 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, mix, and cost of renewable energy investment. In this paper, we ask what the outcomes would be in a more realistic context – the European Union (plus the UK, Norway, and Switzerland), accounting for varying market conditions, transmission limitations, and renewable energy opportunities across the continent. In particular, we compare energy-focused (feed-in premium or renewable portfolio standard (RPS)) and capacity-focused (investment subsidies) renewable policies upon the EU electricity market in 2030 using a power market equilibrium model. The model determines the net costs that must then be recovered from subsidies by accounting for the value of power at different times and places, which results from the simultaneous interaction of supply and demand throughout the network.

We focus on the following specific question:

How do alternative policies impact the mix of renewable and non-renewable generation investment, electricity costs, renewable output, CO_2 *emissions, the amount of subsidies, and consumer prices in the year 2030? Specifically, do capacity-based policies result in significantly more investment and possibly learning?*

One of the contributions of this paper is the quantification of these impacts at the European level with a model with updated renewable cost data and details on the transmission grid, generation mix, renewable potentials, and load distributions for all European countries. Our results give, for the first time, detailed and quantitative insights on the magnitude of inefficiency that results from choosing one type of renewable policy (such as an RPS) to meet the goal of another type (such as a capacity target).

Additional contributions of this paper include the following. One is the modelling of the mixed capacity/energy subsidy policy. Unlike energy or capacity subsidies, the mixed investment/output subsidy has not been modelled before nor have its impacts been quantified. Our model in this regard is new in the electricity market modelling literature.

Another contribution is our evaluation of the efficiency of *national* policy targets for renewable electricity production or capacity (as a

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

whole or per technology) and compare these with a cost-effective EU-wide allocation of renewable energy investment, given resource quality, network constraints, loads, and generation costs across the EU. Comparison of the efficiency impacts of national targets provides an important benchmark for policy makers to understand the magnitude of the efficiency implications of the design of the renewable support policies.

Finally, we provide insights on how the various energy and climate policies interact and how they contribute to achieving the different policy goals of CO_2 emission reduction, cost reduction through learning by doing, and increasing the share of renewables in the energy mix.

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). Fig. 1 shows the regional coverage and transmission grid of the model. In contrast, many other analyses of renewable electricity policies in Europe identified best locations and technologies based on levelized costs or other metrics that disregard the space- and timing-specific value of electricity output (e.g., Del Río et al., 2017). COMPETES uses linear programming to simulate the equilibrium in a market in which generator decisions simultaneously consider how development costs, subsidies, and energy market revenues affect 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.

The paper is organized as follows. Section 2 briefly reviews the literature on model-based analyses of renewable electricity policies in order to situate our capacity-vs energy-subsidy study relative to analyses of other important renewable policy questions. Then Section 3 summarizes the COMPETES model. In Section 4, we present results concerning the impacts of capacity, energy, and mixed capacity-energy policies on costs and energy prices. We show how increased subsidies necessary to meet aggressive targets are distributed between compensation for lower market values, higher rents to inexpensive renewable resources, and offsets of costs for marginal, more costly resources. We compare the magnitude of cost and resource mix differences among the policies to the impacts of another dimension of renewable subsidy design: whether free trade in renewable credits among countries is allowed. Section 5 concludes the paper with a summary of findings and policy implications. Finally, Özdemir et al. (2019) provide 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.

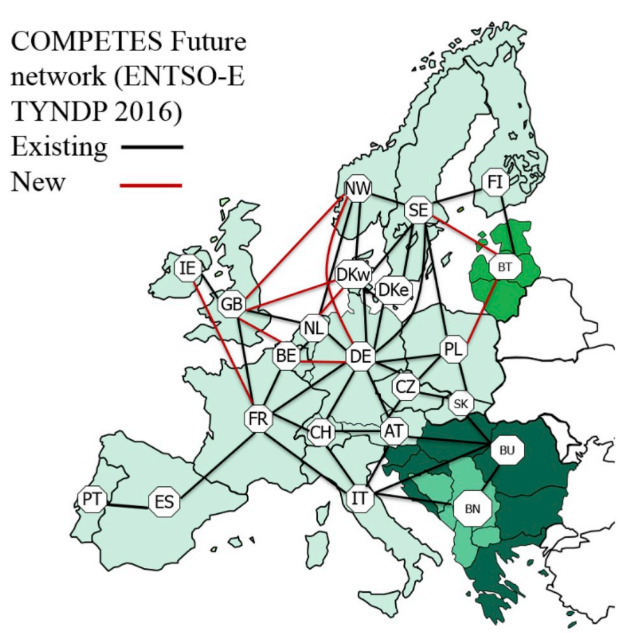

Fig. 1. The geographical scope of COMPETES.

2. Review of renewable electricity policy analyses

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 their goals as 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 four basic sets of questions summarized below. Due to the size of the literature, we only cite illustrative studies for each set.

The first set of questions ask: how efficient are alternative subsidy mechanisms in terms of achieving multiple societal goals, accounting for responses of power markets to subsidies? 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 cost burdens and environmental benefits; providing leadership by example; reducing costs by 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 obligations, auctions, feed-in tariffs and premia, and auctions of publicly owned-sites, as well as demand-pull policies such as green pricing and marketing (Huntington et al., 2017; Del Río et al., 2017; Resch, 2017). For instance, Beurskens (2011) compares several of these policies for the Netherlands accounting for EU-wide markets and policies.

The second set addresses the simultaneous interplay of multiple policies. Such questions include: 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 policy mixes result in inefficiencies in achieving society's overall goals, or if they instead provide important complementarities (Del Río, 2017). Others suggest ways to adjust the policies to lessen conflicts or inefficiencies (Richstein et al., 2015).

A third set of analyses examine 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 final set investigates the effects of particular implementations of individual policies. Some examples include the cost and emissions effects of allowing cross-jurisdictional trade of renewable credits (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 cannot be attained by relying on individual country targets alone (Resch, 2017); separate targets for different classes of renewable technologies (Kreiss et al., 2017); 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 four sets of questions consider policies that subsidize renewable energy (MWh) rather than capacity (MW), as capacity-based mechanisms have been implemented far less frequently. Exceptions are the theoretical analyses by Newbery et al. (2018) and Barquín et al. (2017), who discuss the mechanics and 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. If the avowed goal of renewable policy is to accelerate learning and technology improvement, irrespective of the fact that many of those benefits will spillover to other jurisdictions, then capacity-based policies should be considered because they are potentially more effective in achieving this goal (e.g., Andor and Voss, 2016; Newbery, 2018).

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.

3. Methodology

3.1. Model

A market equilibrium assuming competitive conditions has two characteristics. First, each market party pursues its own objective (profit) and believes that it cannot affect prices nor increase its surplus by deviating from the equilibrium. This is modelled by defining a profit maximization problem for each party, including generators, consumers, and transmission system operators. The second characteristic is that supply, demand, and net imports clear at each node in the network, resulting in nodal prices. 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 formulating and solving an equivalent single optimization model. Real-world problems lead to large-scale complementarity models that are computationally challenging; fortunately, we are able to use the single optimization problem approach here, which allows us to solve systems with millions of variables.

Özdemir et al. (2019) describe our modelling approach in detail. First, we pose a market equilibrium problem under alternative renewable support mechanisms that assumes price-taking behavior among all market parties. Second, we state a single linear program 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. The linear program is an integrated model of economic power dispatch and generation capacity planning, taking into account generation intermittency and transmission constraints between countries. The model also includes seasonal and daily electricity storage from hydro.[1] It is a stochastic linear program, with scenarios representing various load and renewable conditions. For computational tractability, we calculate an equilibrium for a single year. 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; Sijm et al., 2017; Hytowitz, 2018).

Very generally, policy makers can stimulate private investment in renewable energy generators by either implementing a price or quantity-based instrument to provide a subsidy to these technologies. The first alternative consists of defining an administrative price to be paid for renewable energy or capacity (e.g., feed-in-tariff) or an administrative bonus to be paid on top of the market price for energy (e.g., feed-in premium). Tax-based incentives are also of this type. Alternatively, policy makers can fix the desired quantity of energy or capacity, and establish a market mechanism from which the price will emerge based on the costs of supplying renewables (e.g., an auction or renewable portfolio standard). Both general approaches are subsidies, in that renewables will receive revenue that exceeds the market value of energy, and the difference between that revenue and the market price is made up by the government or electricity consumers. From a strictly theoretical point of view, under certainty and in the absence of other market failures, price and quantity policies can each achieve the same quantity with the same total subsidy by appropriate adjustment of the administrative price or quantity requirement (Weitzman, 1974).

In our paper, we consider a quantity-based approach where the feed-in premium price is assumed to be determined by an auction. Renewable generators offer quantity-price pairs for the commodity being acquired (renewable energy or capacity), and the market clearing premium that results in acquisition of the target quantity is determined. Offers whose offer price is less than that clearing premium are accepted, and are paid a subsidy equal to that premium. We compare three 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:

- We model the *energy*-focused policy as a market-based support scheme, i.e., an RPS with an EU-wide renewable obligation target and tradable green certificates. The renewable energy subsidy considered is a feed-in premium type of instrument (equivalently, an RPS) or a green certificate price. Consequently, renewable investors will have an incentive to choose locations where the cost of development less the local market value of electricity production is low. With some other types of energy subsidies such as a fixed feed-in tariff, there is only an incentive to generate at the lowest possible investment and O&M cost, and the value of the electricity to the market does not play a role in the decision.
- We also model the *capacity*-focused policy as a market-based support scheme. The first and simplest variant is represented by a capacity auction with an EU-wide total capacity target. The firms contributing to the target receive remuneration per MW of renewable capacity, which is the clearing price for the capacity target constraint.
- In the second variant of a capacity support scheme (the *mixed investment/output subsidy*), an investment in new renewable generation capacity will receive €/MWh payments determined by an auction, with payments being made in the year of production. The lowest per MWh bids into this auction are awarded payments that are limited as follows: (1) there cannot be payments for more than a predetermined number of MWh per MW capacity over the investment lifetime, and (2) there are no more than T years of payments.

3.2. Input assumptions

We implement the above modelling approach using the market model COMPETES which includes 33 European countries represented by 22 nodes (Fig. 1).[2] Transmission in COMPETES mimics an integrated EU network limited by net transfer capabilities (NTC) between countries or

[1] Seasonal storage consists of hourly Run-of-River (RoR) generation and flexible generation. RoR is the must-run generation, given monthly data on the share of RoR per country. Meanwhile, flexible generation from longer-term 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, based on historical (2011–2016) seasonal availability of water reservoir levels. Daily storage of hydro (i.e., hydro pump storage) is modelled such that the pump storage operators maximize their net revenues by charging and discharging electrical energy within a day.

[2] 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 (aggregated in a single node 'non-EU Balkan'); Romania, Greece, Bulgaria, Croatia, Slovenia, Hungary (combined into 'EU Balkan'); the Baltic countries; Luxembourg (included in Germany); and Denmark, which is split into two nodes due to its participation in two nonsynchronous networks.

regions. NTC values are estimated based on ENTSO-E (2016a) plans. The model adopts zonal pricing within countries which is the current market structure in the European Union and therefore does not take into account domestic locational issues and congestion within a country. Given that COMPETES does not model transmission constraints within a country (with the exception of the DC link between Denmark-East and -West), the model is equivalent to locational marginal pricing. Net power costs for a given country are calculated assuming that power purchases and sales are settled at locational prices. Net cost calculations account for within-country generation costs as well as transmission congestion rents, which are split by countries at either end of the connectors.

For initial installed generation capacities, we use ENTSO-E's Mid-Term Adequacy Forecast (MAF) scenario (ENTSO-E, 2016b) up to 2020, taking into account 2020 renewable policies and targets. 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 construction and decommissioning of gas and coal plants. Annualized investment costs of conventional generation technologies are estimated based on capital cost and lifetime assumptions in Özdemir et al. (2013). Investment costs and potentials for onshore wind rely on the 2013 EU Reference Scenario (Capros et al., 2013). 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 PV and offshore wind and their potentials in the Netherlands use the Dutch National Energy Outlook 2017 (Schoots et al., 2017). For all other EU countries, PV and offshore potentials 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 distances from the shore.

Demand is perfectly inelastic, and consumption for all countries in 2030 is consistent with the Vision 1 scenario of ENTSO-E, 2016a. We use the fuel- and CO_2 prices given by the 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 15 €2010/tonne CO_2 in 2030,[3] although we also do a sensitivity analysis using 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 general 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 h out of 8760) to capture within-year variability, sampled from 8 years of data from Gorm et al. (2015). For sampling, we employ *k*-means clustering to group days with similar patterns of load and renewable generation into 50 clusters (Hartigan, 1975). For every cluster, a single historical day that is closest to the cluster's centroid is selected as the representative day of that cluster, which Nahmmacher et al. (2016) shows will yield a better approximation than using the cluster's centroid. 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. In this way, we account for frequent load and renewable generation patterns represented by large clusters and rare situations represented by small clusters. The weighted average of the sample may deviate from the average of the underlying historical time series. Therefore, hourly wind and solar data of the representative days are scaled to match the 2030 capacity factors by country from the EU 2013 Reference Scenario (Capros et al., 2013). For seasonal hydro storage, we do not consider all days or long sequences of consecutive days. By using the sample of 50 representative days, we formulate the total seasonal generation by multiplying the hourly hydro generation from the sample with the corresponding weights of these representative hours.

4. 2030 EU power market results

4.1. Renewable support policy scenarios

We establish a scenario framework (Table 2) 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 targets, individual member states are implementing policies to achieve their own targets. Therefore, 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, 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.

In addition to the basic policy alternatives shown above, the following variants are also considered:

Table 2
Overview of renewable support policy scenarios.

	RES support policy scenario	Implementation	Target variation in 2030
Overall EU Target	Baseline	No renewable policies in 2030	N.A.
	Energy subsidy	Renewable portfolio standards	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 (Newbery et al., 2018)	MW auction Payments made per MWh up to a maximum MWh/MW within T years	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 2030 renewable capacities in ENTSO-E's Sustainable Transition (ST) scenario (ENTSO-E, 2018).

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

- All three renewable policies are simulated under a higher CO_2 price (€42/tonne, versus €15/tonne in the base case)
- We also consider capacity-based policies with technology-specific targets. This might be rationalized under the assumption that some technologies have more opportunity for learning-based cost reductions than others.

4.2. Economic impacts of capacity vs. energy mechanisms

We discuss three groups of market impacts of the alternative policies. First, we compare the overall market cost of meeting electricity demand and the policy constraints, contrasting their cost-effectiveness in meeting each type of constraint (Section 4.2.1). We then examine their impacts on electricity prices (Section 4.2.2). The final subsection addresses the amounts and destination of renewable subsidies, noting that as subsidy levels increase in order to stimulate more penetration, most of the subsidies go towards offsetting losses of energy market revenues, which fall as penetration rises (Section 4.2.3). Smaller portions go to increasing economic rents earned by cheaper renewables and to offsetting the cost of the costlier renewables that are built on the margin.

4.2.1. Costs of meeting MWh vs. MW targets

The total renewable electricity share in EU in the baseline scenario without renewable policies reaches 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 (22% wind and 6% PV, Capros et al., 2013) and Wind Europe's Low Scenario (22% wind, Wind Europe, 2017). In Fig. 2, we show the annualized EU-wide cost of meeting higher renewable MWh targets by the three EU-wide policies. The energy subsidy model directly puts a floor under the total renewable MWh (equation (22) in Özdemir et al., 2019). 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 models' policy constraints ((23) and (24) in Özdemir et al., 2019) until enough capacity is built such that the annual renewable MWh meets the target.[4] 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 no-subsidy level of 47% by using energy or capacity-focused policies. (Note that by cost, we mean the objective function (25) in Özdemir et al., 2019), which includes generation investment and operations cost as well as customer outages, adjusted for exchanges with non-EU countries.) 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 indeed occurs (Fig. 2, left). Although 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 capacity subsidies). 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 installations. A capacity-focused policy is the cost-effective (first-best) way of reaching a capacity target level for renewables, whereas achieving the same level of renewable capacity by energy subsidies is more costly. For instance, the 377 GW of new renewables that results from the 65% RPS policy could also be achieved directly by a capacity policy at an incremental cost that is 26% lower than the 11B€/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 between these two cases as it has characteristics of both capacity and energy policies. For instance, the incremental cost of the mixed policy 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 (11B€/yr) and 22% lower than the capacity subsidy policy's cost (18B €/yr). Compared to the energy-based policy, the mixed policy incents 57 GW less wind and 156 GW more PV, with a net increase of 99 GW renewable capacity.

The subsidies needed 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 a penetration of 47%) to 13 (with 55% penetration), 21 (with 60% penetration) and 33 €/MWh (at a 65% penetration). These are the RPS constraint's shadow prices 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. Interpreting the solid curve in Fig. 2 (right), the subsidy for the capacity policies is 30,204 €/MW/yr (for 243 GW of investment), 47, 614€/MW/yr (with 377 GW), and 57,354 €/MW/yr (with 550 GW). The implicit marginal cost of providing that same capacity by instead using an RPS energy-based policy is, of course, higher.

The inefficiencies identified in Fig. 2 depend on the price of carbon. In Fig. 2, we assume an ETS price of €15/tonne; however, since carbon prices recently have been higher, it is of interest to consider higher values. Fig. 3 shows the impact of a higher price (€42/tonne) on the energy- and basic capacity-based policies relative to the base case of Fig. 2. Two trends are evident. One is that the higher carbon price results in a greater penetration of renewables (53% of energy compared to 47%) without the need for subsidies. The higher carbon price in the absence of a renewable subsidy behaves similarly to an energy-focused subsidy that achieves the same renewable share under a lower carbon price, in terms of rewarding renewable MWh generation and steering the mix of renewable additions towards wind rather than solar.

A second trend resulting from a higher carbon price 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 inefficiency of 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

[4] In general, the policy constraints in our model are linear constraints of type $Ax \geq B^*$, where the right-hand parameter B^* represents an EU-wide policy target while variable x represents the model's decision variables. For a capacity auction, we simulate different levels of policy targets by changing B^*. In cases where we wish to simulate the use of a capacity-based mechanism to achieve an energy target, the capacity target B^* is iteratively modified as follows. Let $r = Ex$ be the total renewable energy produced from a solution x, with E being the vector of coefficients defining qualifying renewable energy production. Let R^* be the renewable energy target. In the capacity model, $x = x(B^*)$ is a function of the capacity target. The problem of choosing a capacity target B^* in order to achieve the energy target R^* is equivalent to a search procedure in which B^* is adjusted so that $R^* = r(B^*) = Ex(B^*)$. This adjustment process consists of solving the capacity model for a given B^*, calculating $x(B^*)$ and $r(B^*)$, and then noting the deviation from the renewable energy target $r(B^*)$-R^*. If this is nonzero, the procedure has not converged, at which point we use a discrete version of the Newton-Raphson method to suggest the next value of B^* that will bring r closer to R^*. This iterative procedure converges quickly.

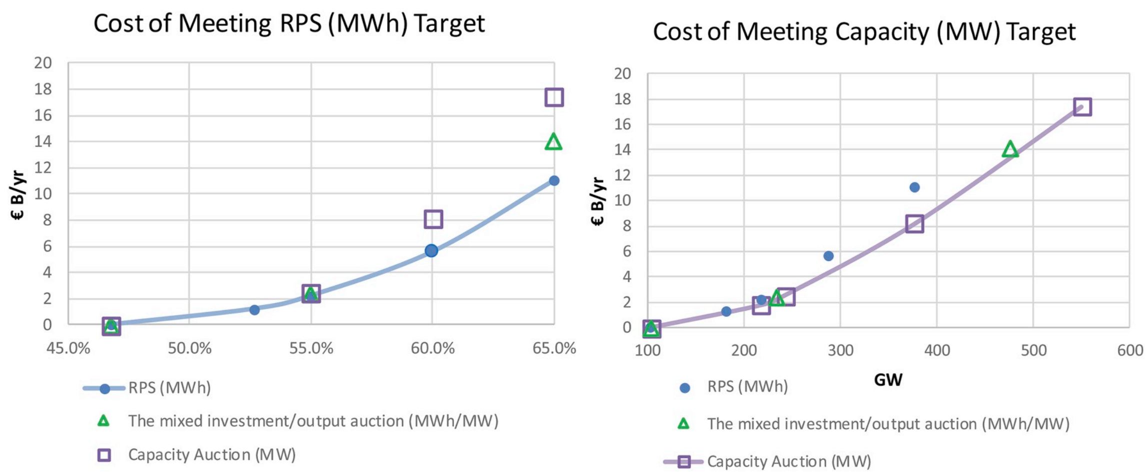

Fig. 2. Incremental generation cost/yr of meeting MWh vs MW targets under the three policies.

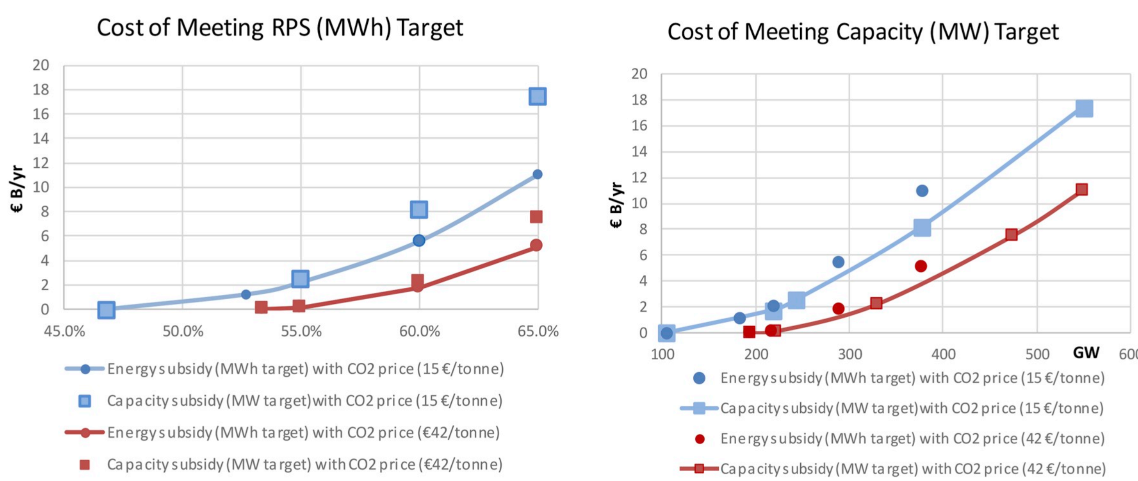

Fig. 3. Effects of carbon price on incremental generation cost/yr of MWh vs MW targets under energy- and capacity-based policies.

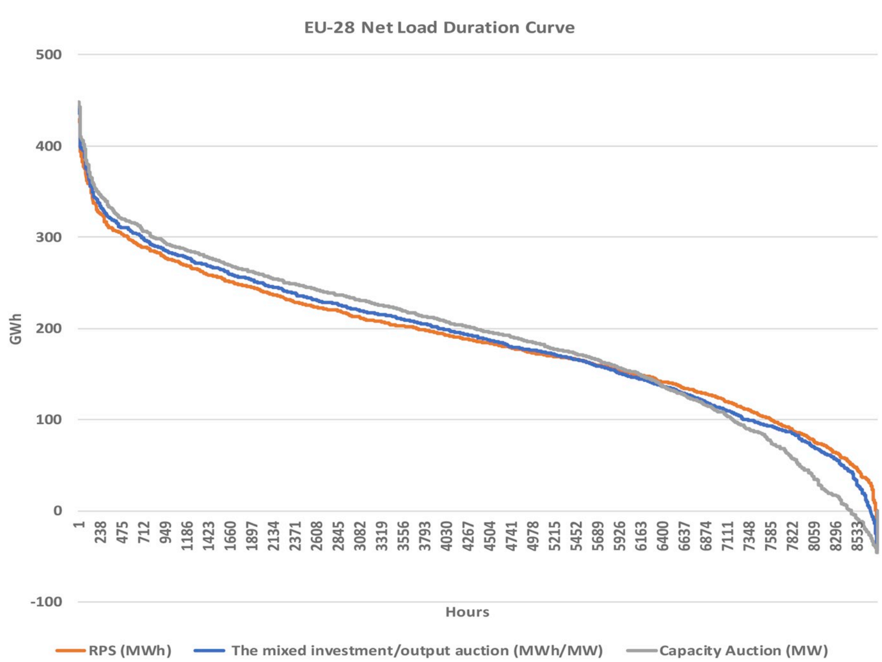

Fig. 4. EU-wide annual net load duration curve under three renewable support schemes achieving 65% renewable share.

using a capacity policy under the lower carbon price, but only about €1.5B/yr more under the higher price. Thus, our conclusion that inefficiencies on the order of a billion €/yr result 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.

4.2.2. Price and elasticity impacts

The main effect of choice of instrument (capacity versus energy subsidy) upon electricity prices is not upon average electricity prices, but upon their distribution over time. Because the output of different renewable generation technologies coincides to a greater or lesser extent with peak loads, the different policies have distinct effects on the volatility of net demand facing thermal and hydro generation. The EU-wide net load duration curve is steeper under a capacity subsidy (as illustrated in Fig. 4 for 65% renewable share, which are the right hand solutions in Fig. 2). For instance, the net load during winter peak hours is 5% lower under the RPS policy because of its higher wind installation. On the other hand, the EU experiences its own version of the duck curve under the capacity policy's high solar penetration, so that off-peak net load under capacity subsidies is sometimes negative.

These load effects are reflected in prices. Capacity subsidies result in higher peak prices during winter and lower off-peak prices (between 12:00–14:00) during other seasons (due to higher solar PV generation). The average differences between max and min prices within a day are higher under capacity subsidies. For instance, the average difference across Europe between max and min prices during a winter day is 66 €/MWh under RPS and 71 €/MWh under capacity subsidy (given a 65% renewable energy penetration target). During summer and fall, these relative impacts of the different policies on prices differ even more. For instance, the average difference between max and min prices during a fall day is 11 €/MWh under an RPS and 22 €/MWh under a capacity subsidy.

If there is significant price elasticity, then such price differences would affect loads and, ultimately, welfare comparisons of the policies. However, our policy comparisons assumed a zero price elasticity of demand. Given that most retail consumers do not face prices that vary according to actual system conditions, and that elasticities are relatively low, this assumption is unlikely to significantly affect the comparison of policies. As just noted, capacity policies yield an approximately 5–10 €/MWh wider spread in daily prices than energy policies for most countries, under a 65% penetration of renewable energy. With price elasticities being on the order of −0.1 to −0.2 and retail rates equal to roughly 200 €/MWh, the 5–10 €/MWh wider spread in daily prices under capacity policies would affect loads by no more than 1%, even in the presence of real-time retail pricing. Since retail rates for most consumers do not follow spot market price variations, the elasticity effect of differences in price variations among policies is unlikely to be significant.

4.2.3. Where does the subsidy go?

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

This question is important for two reasons. First, policy makers would prefer to see that subsidies are used to encourage investment that would otherwise not occur, rather than increase economic rents earned by investments that would happen anyway. Second, it is of interest to understand whether the subsidies go mainly to offset higher technology costs of the incremental investment, or to compensate for falling energy prices resulting from larger investment. Price effects of larger amounts of renewables have received a great deal of attention in the literature and popular press, and this is the first time to our knowledge that it has been quantitatively compared to the subsidies that would go to higher technology costs or economic rents.

Fig. 5 shows the average subsidies for on-shore wind and PV as a function of total energy penetration, and how those subsidies are partitioned into the three sources (capital costs of more costly sources, economic rents, and compensation for decreases in market value). The subsidy rises to as much as 43 €/MWh (equivalent) as penetration increases, and is mostly devoted to compensating for lost market value. In general, for both capacity and energy policies, Fig. 5 shows that most of the subsidy covers the losses due to the declining value of energy produced. The portion of the RPS subsidy that compensates for the decrease in market value grows 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 portion of the capacity subsidy that compensates for decreased market value increases to 14 €/MWh (out of 18 €/MWh) for onshore wind, and to 29 €/MWh (out of 45 €/MWh) for PV when renewable penetration achieves 65%.

The energy subsidy favors onshore wind investments since wind has a higher capacity factor and contributes directly to the MWh target, whereas the capacity subsidy supports more solar-PV investments since 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. 5), 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 we show on the left side of Fig. 6, where significant economic rents are earned; in comparison, this does not occur in Denmark-West because the resource is not fully exploited there (Fig. 6, right). On the other hand, economic rents never occur for solar-PV because the potential resource is not fully used in any region in any scenario.

We now discuss the Belgium and Denmark-West onshore wind results in more detail. Fig. 6 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, providing economic rents. In Denmark-West, in contrast, investments in wind-onshore increase further when the target exceeds 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 widens the 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 PV for each country are given in Appendix C of Özdemir et al. (2019). Note that as the renewable penetration increases, the market value of renewables decreases while the average peak prices when RES is not delivering increases. The overall

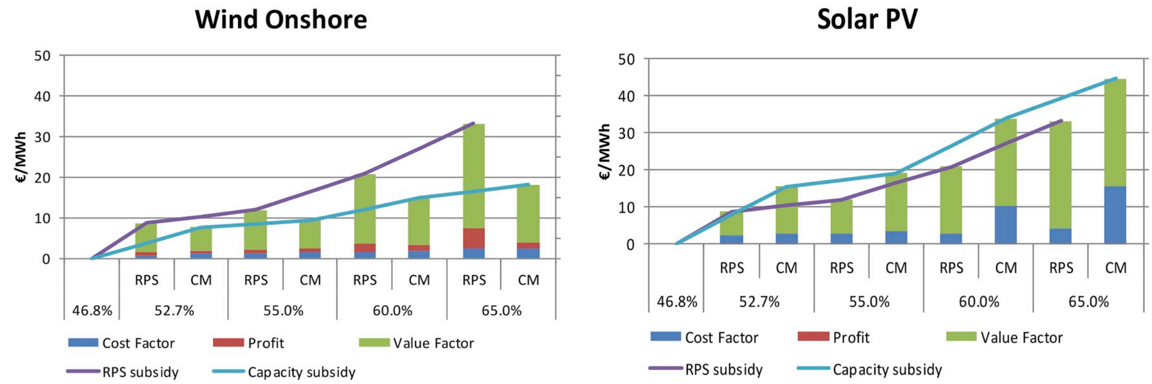

Fig. 5. The contribution of energy and capacity subsidies per unit output for onshore wind and solar-PV (to make up for rising renewable costs, provide scarcity rents, and compensate for reduced value in the energy market).

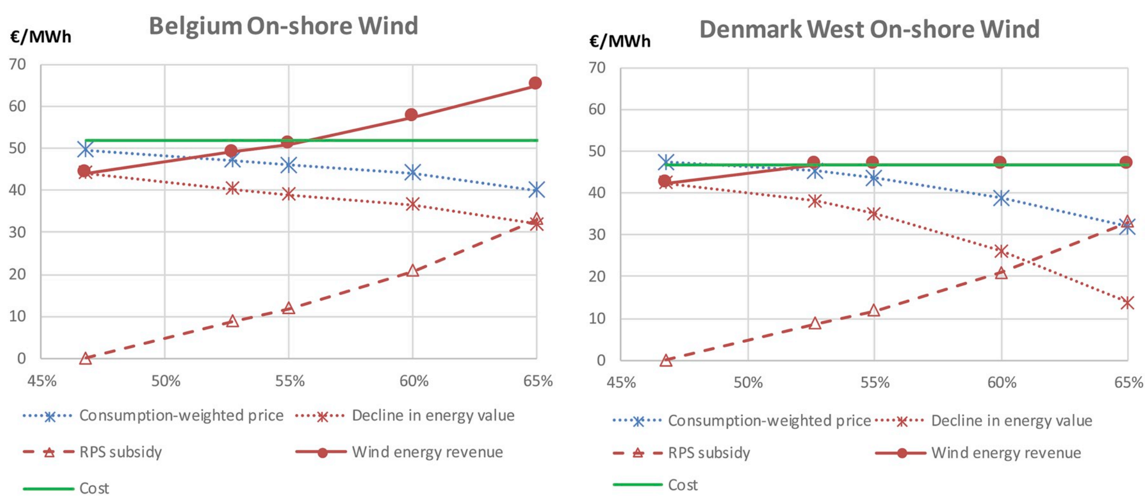

Fig. 6. Total market value and sources of revenues for Belgium onshore wind producers (where the full potential is eventually developed) vs Denmark-West (where the its potential resource is not fully developed) under the RPS subsidy. Market Energy Price is the consumption weighted bulk power price, while Energy Value is the average revenue received by wind.

wholesale prices we report are the appropriately weighted average across both cases, and also fall, but not by as much as the decrease in market value of renewables.

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. 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., in Denmark-West as well as other countries.

4.3. Distributional impacts of capacity vs energy mechanisms

4.3.1. Technology neutral 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 members in general aim for certain share of renewables in their generation (energy) mix; however, they also want to reduce costs through learning-by-doing. Although RPS-type energy subsidies are the most cost-effective way of achieving a renewable share target, at least in the short-term, the 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 (Fig. 7) while increasing the cost of the incremental renewables by about 7 €B/yr, or over 50% (Fig. 2). When aiming at the same target for renewable energy, capacity subsidies boost solar-PV installations (which 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 that policy has characteristics of both capacity and energy policies.

Fig. 8 shows how the wind and solar investments given in Fig. 7 are distributed within Europe under three policies achieving 65% renewable share. With an RPS, wind capacity investments are higher in windy locations such as northwest and west Europe. Under a capacity mechanism, some of the investments in wind capacity decrease in northwest Europe while solar PV investments increase elsewhere, in particular in south and eastern Europe. This has an impact on the cross-border congestion. As an index of this effect, we calculated congestion rents as an indicator of congestion between countries. The energy subsidy results in more congestion from northwest Europe to eastern Europe

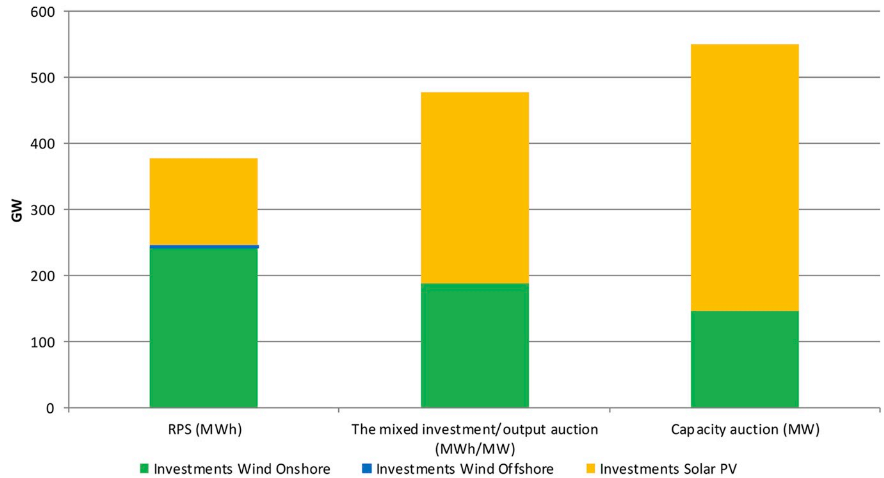

Fig. 7. Incremental investments compared to base case: wind and solar under energy and capacity-focused subsidies achieving 65% renewable share: Technology neutral case.

because of the need to transmit wind power from the windy locations in the northwest. Under that policy, for a renewable penetration of 65%, the average congestion rent per MWh of demand is 3.1 €/MWh, about 12% of the average cost. Under the larger amounts of solar investment resulting from the capacity subsidy, the flows and congestion from northwest Europe to eastern Europe decrease and the total congestion rent (load payments minus generator revenues) drops by 31%. The mixed input/output subsidy lies in between with a drop of total congestion rent by 18%.

4.3.2. *Technology-specific targets*

The large differences in types and locations 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, quantifying effects on cost, renewable MWh, and locational incentives. 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 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. 7). 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%). But this is over an order of magnitude smaller than the >3B€/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, right side of Fig. 2).

Turning to the locational implications (Fig. 9) of energy and capacity subsidies that achieve the same GW of wind and solar capacity, we see that capacity subsidy shifts 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. 7).

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

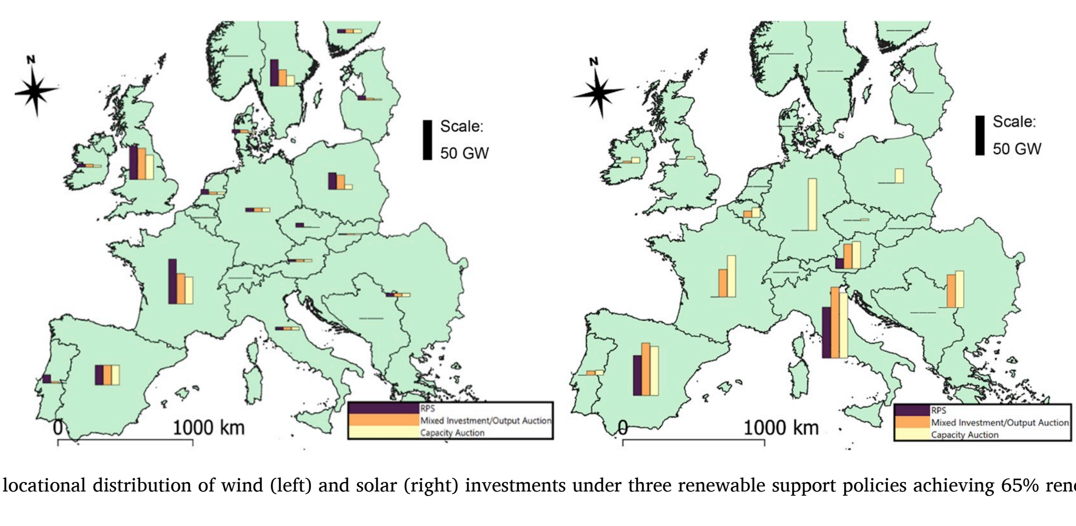

Fig. 8. The locational distribution of wind (left) and solar (right) investments under three renewable support policies achieving 65% renewable share.

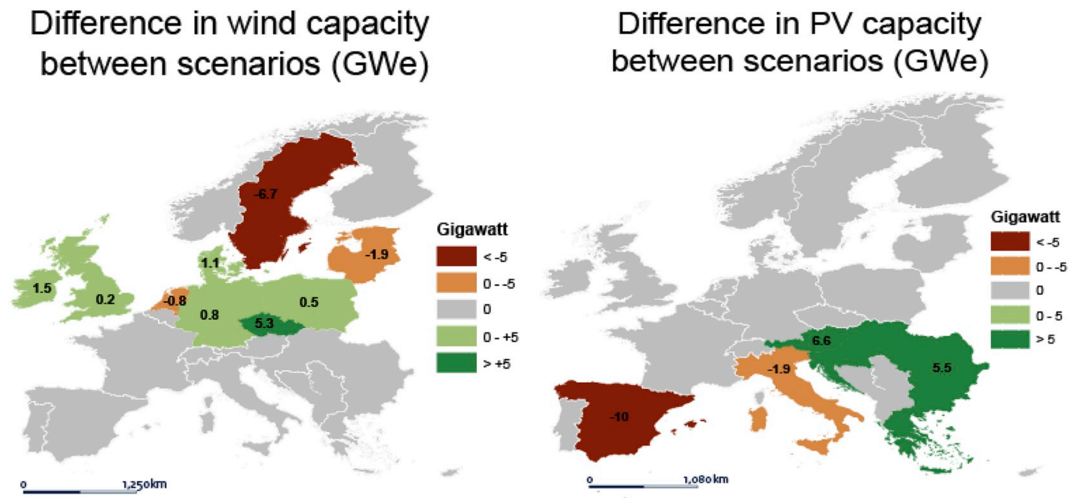

Fig. 9. The changes in installed wind capacity (left, out of 246 GW investments) and installed solar-PV capacity (right, out of 131 GW investment) when technology specific capacity subsidies are used to achieve the same GW investments as the RPS/energy subsidy with 65% renewable share target. (Note: shifts less than 0.5 GW in magnitude rounded to zero).

377 GW of investment without limiting the type of investment can save more than 3B€/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.

4.4. Electricity carbon emissions under capacity vs energy mechanisms

Alternative support schemes will affect the energy mix and therefore power sector CO_2 emissions in different ways, depending on the existing generation mixes in countries where renewables increase. With an RPS, we see a smaller reduction in emissions (relative to the base case) compared with the capacity-based subsidy for a given amount renewable energy share, especially at high renewable penetrations (Fig. 10). This occurs because, for a given renewable share, an RPS results in more investment in wind capacity in northwestern and western European countries that already have relatively low-carbon technologies (e.g., hydro, nuclear, gas-fired). For instance, in Sweden, RPS-stimulated wind replaces nuclear and hydro. Moreover, the RPS results in less solar-PV production in countries with significant coal generation, for example Germany, so there is more coal use there than under the capacity-based subsidy (Fig. 11). This difference in CO_2 impacts occurs both at the 15 €/tonne and the 42 €/tonne CO_2 price. Meanwhile, the mixed energy/capacity subsidy yields emissions that are slightly (0%–1%) higher than the capacity-based policy.

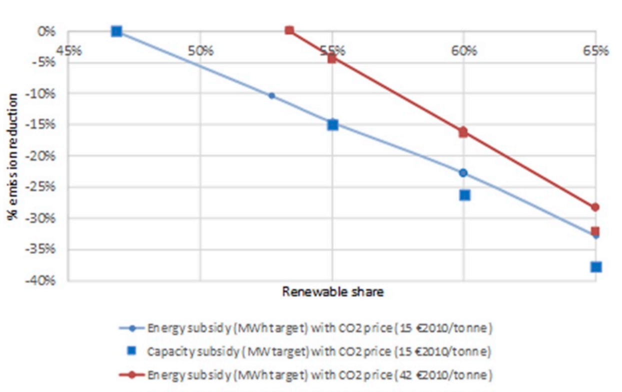

Fig. 10. Percentage emission reductions (relative to Baseline) under energy vs capacity mechanisms.

4.5. Comparison to inefficiencies of implementation of country-specific targets

An important question is: how significant are the differences between capacity- and energy-based policies compared to other choices in renewable policy design? One of these policy options is implementation of country-specific targets without allowing between-country trading of renewable energy credits. It is shown by other studies that achieving national targets without allowing trade 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 20.4B€/yr more expensive. Newbery et al. (2013) estimated an annual benefit of such trading of 15.4–30B€/yr over the period 2015–2030.

As shown in Fig. 12, 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 8.5B€/yr compared to the baseline scenario. These country targets are based on reported national plans complied by ENTSO-E, 2018. The COMPETES model estimates that this cost is about

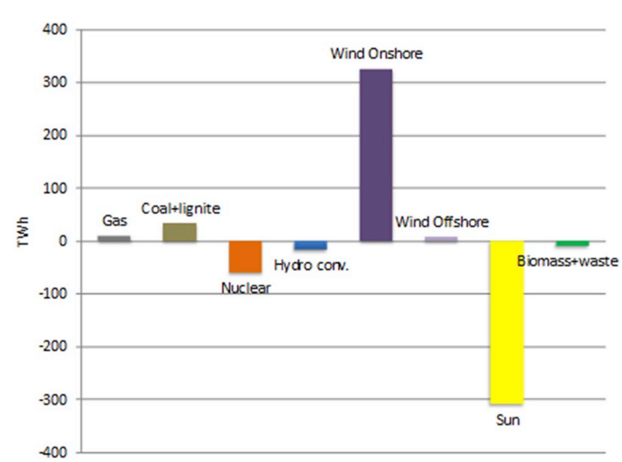

Fig. 11. Differences in EU-28 generation-mix from RPS mechanism compared to capacity mechanism at 15 €/tonne CO_2 price, both achieving 65% renewable share (from right hand solutions in blue in Fig. 10). (For interpretation of the references to colour in this figure legend, the reader is referred to the Web version of this article.)

seven times higher than the incremental cost of achieving the same renewable share by an EU-wide RPS (1.2B€/yr). Most of the cost increase of 7.3B€/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 (2.0B€/yr). In this case, an EU-wide capacity auction actually achieves a higher renewable share (54%) than the national targets. Of the 8.5–2.0 = 6.5B€/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.

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 PV (9% of total generation), onshore wind (19%), and offshore wind (7%) generation as achieved by the national targets, as in 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 4.6B€/yr. This is 3.4B€/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 = 7.3B€/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 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. This is 3.3 € B/yr higher relative to the least-cost means of achieving same total renewable capacity in EU (i.e., 2 € B/yr). When compared to the 6.5 B€/yr incremental cost of country specific targets, this indicates that the inefficiency is roughly evenly divided between wrong mix and wrong location of technologies.

In summary, the inefficiencies of prohibiting trade (as much as ~7 billion €/yr, Fig. 12) are twice as large or more as the inefficiency of using an RPS to achieve a capacity target, or vice versa (as much as ~3 billion €/yr, Fig. 2).

5. Conclusions and policy implications

Energy and climate policies in many countries include both different policy instruments and different policy objectives. For the electricity sector, the main policy instruments are subsidies for renewables, CO_2 taxes, and emission trading schemes. Policy goals include reducing CO_2 emissions, realizing specific shares of renewable energy, and reducing the costs of renewables through learning by doing.

Generally, policy makers do not clearly state which instrument is targeted at which policy objective. However, different policy instruments have different effects on the various policy objectives and there is a trade-off involved in terms of costs and policy effectiveness of different instruments. Moreover, the various policy instruments will also interact with each other, thereby affecting both the overall costs and effectiveness of the energy and climate policy package.

Our analysis illustrates the costs and effectiveness of different renewable energy policy instruments for the possible policy objectives at the EU level with a model with updated renewable cost data and details on the transmission grid, generation mix, renewable potentials, and load distributions for all European countries. This provides policy makers with insights concerning trade-offs between instruments and policy objectives and concerning the magnitude of the costs of using specific policy instruments to achieve certain policy objectives. Our research provides three main takeaways for policy design.

First, the choice between realizing a share of renewables or promoting learning by doing has clear implications for the policy instrument to be used. An energy subsidy scheme is more cost-effective in realizing renewable energy production than a capacity scheme. And vice versa, if learning by doing is the main policy objective, a capacity subsidy is more beneficial. A mixed investment/output subsidy falls in between these cases as it has characteristics of both capacity and energy policies. This result is consistent with previous theoretical analyses that argue that capacity-based subsidies are potentially more effective in unit cost reduction in the long-run through learning by doing (e.g., Andor and Voss, 2016). Our results confirm this argument with detailed market simulations in a realistic landscape focusing on the practical impacts on short-run technology adoption and costs. We do not quantify longer-run impacts on learning.

Learning-by-doing can be promoted using technology-specific targets. This might make more sense since the opportunities for cost reductions will differ among technologies in part because they are at different stages of development. However, our analysis indicates that adopting technology-specific targets will reduce the cost advantage of capacity-based policies by an order of magnitude, so that the choice between the policy instruments becomes less clear-cut in terms of cost-effectiveness.

The difference in cost-effectiveness between an energy subsidy, a capacity subsidy, and a mixed investment/output subsidy is also reduced when there is a high CO_2 price. The interaction between these policy instruments lowers the cost of a capacity subsidy more than the costs of an energy subsidy. Consequently, a capacity subsidy can be used both to promote learning-doing and realize a target share of renewable energy in a cost-effective way if carbon prices are higher than today.

The second main takeaway concerns emissions. In particular, an important rationale for stimulating renewables in electricity generation

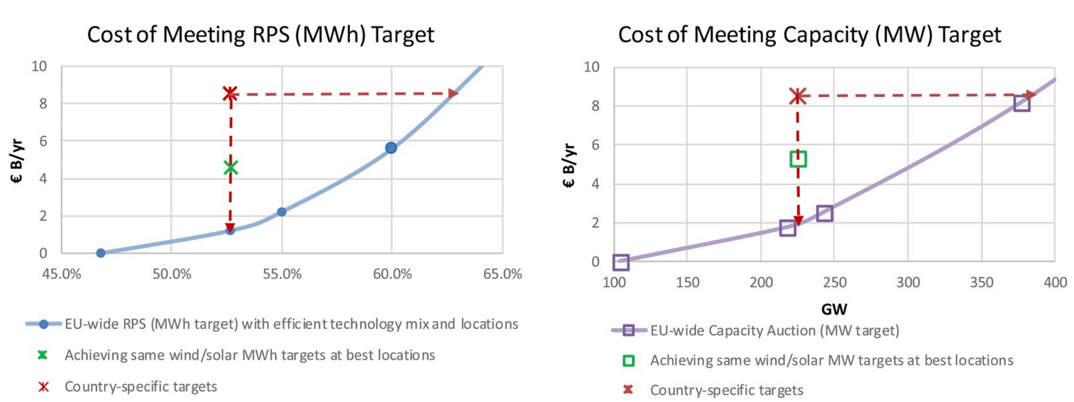

Fig. 12. The cost of inefficient technology-mix and locations resulting from country-specific targets.

is to reduce CO_2 emissions. Different support schemes will affect the energy mix and therefore CO_2 emissions in different ways, depending on the generation mix in the countries where the development of renewables will be stimulated. Given the types of renewables in different European countries and the existing generation mix, an energy-based support mechanism results in smaller emission reductions than a capacity-based support mechanism that achieves the same level of renewable energy. Therefore, in summary, a capacity-based mechanism has two advantages compared to an RPS for a given level of renewable energy production: its greater investments in capacity potentially contributes more to technology improvement through learning-by-doing, and it reduces CO_2 emissions more. These differences are more pronounced at higher renewable penetration levels. To the extent that decreases in power sector CO_2 emissions are compensated for by increases in emissions in other sectors due to trading under the EU Emissions Trading System, the CO_2 benefits of the capacity policy are reduced. However, the advantages of the capacity policy come at a higher cost, as a capacity-based scheme is more costly than an energy-based scheme.

The third policy takeaway is the new estimates that our analysis provides of the cost-effectiveness of a European objective for renewables instead of a country-by-country approach. If energy or capacity targets were to be achieved through country- and technology-specific targets without trading renewable credits, then the costs would be several times higher than the incremental cost of achieving the same renewable share by an EU-wide target. While this is a well-known result from earlier studies, we show that the magnitude of efficiency impacts of national targets are twice or more as large as the efficiency implications of capacity-versus energy-based renewable support policies. Thus, if policy makers are concerned with the efficiency impacts of a policy instrument, they should focus on trade first since the choice of capacity versus energy targets matter less. 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.

Finally, we have also examined the impact of renewable support schemes on the distribution of renewable investments and congestion within Europe as well as the electricity price impacts, and the fate of the subsidies. The lower amounts of wind capacity investments in northwest Europe together with the larger amounts of solar investment in eastern Europe under capacity subsidy result in less congestion in the northwest to east direction. As a result, the total congestion rent drops by 31% at a renewable penetration of 65%. This difference is large enough to be relevant to benefit-cost analyses of potential transmission reinforcements by ENTSO-E. Finally, under either policy, we show that 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 Denmark-West will fall by two-thirds. This loss of revenue must be made up by subsidies if renewable development is to occur.

Declaration of competing interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

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