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JEL Classification: H23 (environmental externalities), L94 (electricity industry), Q28 (renewables policy), Q48 (energy policy)

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David Newbery, Michael G. Pollitt, Robert A. Ritz, Wadim Strielkowski
Energy Policy Research Group (EPRG)[1]
Judge Business School & Faculty of Economics
Cambridge University, U.K.

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This paper presents a set of policy recommendations for the market design of a future European electricity system characterized by a dominant share of intermittent renewable energy supply (RES), in line with the stated targets of European governments. We discuss the market failures that need to be addressed to accommodate RES in liberalized electricity markets, review the evolution of the EU's RES policy mechanisms, and summarize the key market impacts of RES to date. We then set out economic principles for market design and use these to develop our policy recommendations. Our analysis covers the value of interconnection and market integration, electricity storage, the design of RES support mechanisms, distributed generation and network tariffs, the pricing of electricity and flexibility as well as long-term contracting and risk management.

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1. Introduction

In 2014 the European Council confirmed the EU's 2030 targets for tackling climate change as a reduction of at least 40% against 1990 greenhouse gas emissions and increasing the share of energy from renewable sources to 27%. It is currently putting in place the legislation to deliver this.

Given the difficulty of decarbonizing transport and heating, the electricity sector will continue to bear a significant burden arising from economy-wide decarbonization. Achieving this will require high shares of renewable energy supply (RES) in the electricity system, in light of the limited opportunities for expansion of hydro power and widespread resistance to nuclear power. Fortunately, rapid technological progress in wind and solar energy, combined with increased use of interconnection, existing hydro resources, new battery technologies and an increased role for the demand side (facilitated by smart meters) suggests that a high-RES electricity system is not only a necessary outcome of the 2030 policy targets but also a realistic future scenario.

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To date, Europe has made remarkable progress in creating liberalized and competitive wholesale markets for trading electricity within and across national boundaries. The liberalization process, beginning in the 1990s, was accompanied by large-scale private investment in gas-fired power generation, which cut costs, reduced CO_2 emissions and improved environmental quality. The creation of competitive wholesale markets with hourly or half-hourly varying prices was the central mechanism for matching supply and demand, and until the mid-2000s in some countries also for directing generation investment.

The advent of intermittent renewables with high upfront capital costs but very low short-run running costs has led to a reduced role for the market in guiding investment. Governments now dominate by setting the subsidy regimes and capacity mechanisms that determine new generation investment.[2] The share of renewables in EU-28 electricity production has increased remarkably over the last decade to reach 28% in 2015, driven by generous subsidies and priority dispatch connection terms. However, raising the renewables share to 50%+ by 2030 will be challenging without substantial modifications to the current "1st generation" market design.

In this paper, we review the evolution of liberalized electricity markets and EU renewables and climate policy to date. We note the unintended problems which have arisen under the current market design and existing RES subsidy schemes. We then outline key elements of a "2nd generation" high-RES market design, which provides better price signals, better incentives for RES investment and operation, and greater system flexibility.

We begin by advancing six principles of good electricity market design. These include: correcting as directly as possible the market failures in current market designs; allowing for cross-country variation in market design; using price signals and network tariffs to reflect the value of all electricity services; collecting network fixed costs in as efficient and equitable a way as possible; de-risking low-carbon investment; and retaining the flexibility to respond to new information on the attractiveness of different low-carbon technologies. We then provide a more detailed analysis of the key elements of a new market design and present a number of policy recommendations.

We find that there are still substantial short-term benefits of further European cross-border market integration (equal to around 2-3% of overall generation costs) and significant potential value in increased interconnection. Interconnectors exploit differences in wind and sun conditions across regions and so reduce the supply variability due to intermittency; higher RES penetration further raises the value of market integration. It should be a policy priority to ensure proper remuneration of the services provided by interconnectors so as to incentivize efficient private investment, including for more connection to markets with large hydro reserves such as Norway.

Next, we discuss the challenges around the widespread uptake of electrical energy storage. We observe that the potential of electric storage, including from electric vehicles (EVs), remains tiny compared to existing pumped and hydro storage. Battery storage looks likely to play two main future roles: deferring upgrades in transmission and distribution

[2] Capacity markets are now used in tighter markets in the face of low energy prices and reluctance to invest in the firm and flexible capacity (e.g., fossil fuel generation plants, storage) that are currently needed to meet reliability standards.

systems by shaving peak use, and improving the management of power flows on the electricity network by varying the charging rates of EVs. The surrounding incentives and business models that will allow batteries to capture this value still need to be clarified.

We then examine possible improvements to the design of renewable support mechanisms, which yield better signals around where to locate renewables across Europe. We suggest a move from current output-based (per MWh) feed-in-tariffs to support more based on capacity, for which procurement prices are determined by auctions. As the system becomes more capital-intensive (rather than fuel-intensive), such competitive RES auctions can reduce current market distortions and help further bring down the cost of capital.

We identify issues arising from the current pricing of transmission and distribution services. We suggest that network charges for distributed generation (DG), such as rooftop solar PV, need to be made more efficient. Current charging mechanisms have led to distortions and wealth transfers from poorer to richer households—and these are rising in magnitude and need to be considered alongside other policy objectives. We recommend that the apportionment of charges between fixed, off-peak and peak use of system charges needs to be changed to be more cost-reflective.

We then turn to improvements to the design of power and ancillary service markets. A system dominated by intermittent renewables enhances the need for more granular pricing of electricity over space and time. The scope for nodal pricing of electricity has increased in tandem, given recent improvements in computing power and smart metering. A move towards more granular electricity prices will help improve location decisions for generation investment, and enhance the value of greater system decentralization.

Finally, we discuss risk management and long-term contracting in a high-RES system. We suggest less reliance on politically-backed long-term indexed price contracts that have recently been used to support renewables and nuclear investment. The preferred design of capacity auctions should employ "reliability options" because these help retain efficient spot prices. Policy should support the deepening of markets for forward contracts and employ long-term procurements contracts only where necessary to reduce risk and the cost of capital.

While our arguments are applicable across different European countries, many of our specific examples are drawn from the Germany, Italy, Spain and the UK. We touch on other elements of market design only as by-products of this analysis, including demand-side response, related issues arising for retail electricity markets, and optimal support mechanisms for low-carbon RD&D.

The paper proceeds as follows. Section 2 reviews the economics of liberalized electricity markets and the EU's renewables and climate policies.[3] Section 3 gives an overview of the market impacts—good and bad—which renewables have had to date. Section 4 sets out principles for electricity market design in a high-RES world. Section 5 presents our analysis and recommendations for (i) interconnectors and market integration, (ii) electric energy storage, (iii) RES support mechanisms, (iv) distributed generation, (v) short-term pricing as well as (vi) long-term contracting and risk management. Section 6 offers broader concluding remarks on policy design for a high-RES future.

[3] For a useful book-length analysis of liberalized electricity markets and EU climate and energy policy, see respectively Stoft (2002) and Buchan and Keay (2015).

2. Liberalized electricity markets and EU renewables policy

2.1. Liberalized electricity markets and market failures

Though often conceived as a single homogenous product, electricity in fact involves a range of services so its wholesale value is made up of the energy value (kWh), the value of reliability (i.e., the ability to meet demand) provided by capacity (kW), and quality of service at a particular location, which is provided by a range of ancillary services (voltage stability, frequency, reactive power, etc.).

The key physical challenge is that supply must equal demand at all nodes of the system in real time, without resort to stockholding. On the supply side, renewables such as wind and solar PV come with smaller unit sizes but proportionally larger capital costs than traditional generation assets such as coal and gas; they also add the key challenges of dealing with intermittency and non-responsiveness to system condition (O'Sullivan et al., 2014). Electricity demand is volatile but also largely unresponsive to prices in the short run since most consumers do not see the costs of their electricity in anything close to real time.

Perhaps the most important market failure lies in environmental externalities, notably air pollution and carbon emissions (Borenstein, 2012). The deployment of renewables comes with substantial learning benefits (declining unit cost as the installed base grows) that spill over to other market participants. Without proper support, learning and R&D in such new technologies may therefore be insufficient from a social viewpoint (Jaffe et al., 2005).

Legislative packages since 1996 have opened the sector to vertical unbundling and competition. In liberalized markets, large players in the wholesale market may be able to exercise market power to drive up prices—especially when capacity is tight (Newbery, 1995). This is one motivation behind wholesale price caps, which limit market power in the short run. However, they in turn lead to the problem of "missing money" (Joskow, 2008): prices do not fully reflect scarcity in tight market conditions, reducing profitability and capacity investment over the longer haul. Similarly, the presence of "missing markets", notably forward prices over longer horizons for all products (capacity, energy and quality of service) impedes efficient risk management.[4]

This wide range of market and policy failures means that electricity cannot easily "self-organize" in the way that many other industries do (see, e.g., Kiesling, 2009). At a minimum, policymakers need to create an appropriate framework in which the private sector can deliver on climate targets at acceptable costs while still supplying reliable power over the short and long term.

2.2. EU climate and renewables policy

EU renewables policy is guided by three main objectives: (i) to secure energy supplies that ensure reliable provision; (ii) to create a competitive environment for energy providers to deliver affordable energy prices; and (iii) to support sustainability by lowering greenhouse gas emissions, pollution and fossil fuel dependence (European Commission, 2016).

[4] Even in Germany, the MS with the most liquid forward markets, virtually no forward prices exist beyond a 3-4 year horizon. See ECA (2015) for a recent overview of European forward markets.

The 2009 RES Directive (2009/28/EC) put forward a legally binding target for renewable energy sources to cover 20% of total EU energy consumption by 2020.[5] For many countries, electricity is likely to be the leading sector so the national RES targets imply significantly higher shares of renewable electricity. In the UK, for example, a 15% overall RES target might require a RES electricity (RES-E) share of 30-40%.

The importance of deep decarbonization of the electricity sector arises because of the difficulties in decarbonizing transport and heating—which are shared across much of Europe. Coupled with the limited scope for nuclear new build up to 2030, this suggests that high shares of renewables in the electricity system by 2030 are going to be critical for achieving climate targets. Based on a recent EU-28 study (European Commission, 2016b), the renewable electricity share will rise from 28% to 43% under current policies—but the 2030 climate target of a 40% GHG reduction nonetheless is missed. (Currently policies achieve a 35% emissions cut on 1990 levels; put differently, they fall around 290m tons short of the 2030 target, which would require an additional 14% of current fossil-fuel produced electricity to become zero carbon). This suggests that 55%+ RES-E is likely to be necessary to hit the target in many EU countries.

The 2015 *Energy Union Package* (European Commission, 2015), clarified and updated in the 2016 *Clean Energy Package*, proposes integrating RES-E through market-based schemes. It also envisages greater longer-term policy coherence through a stable investment framework that reduces regulatory risk for investors and achieves security of supply. There will be an EU-wide target of 27% of gross final energy from RES by 2030, supported by voluntary commitments and reporting—rather than mandatory national targets.

An important feature of EU policy is that it sets targets for both RES and carbon emissions reductions. The RES target is designed to encourage Member States to continue subsidizing RES above the value of the carbon saved to compensate for learning externalities that continue to drive down costs. However, since the RES target also reduces emissions, it decreases the carbon price in the EU ETS (for a given CO_2 cap), which in turn perversely favours more emissions-intensive generation—unless the cap is suitably adjusted at the same time. Böhringer et al. (2009) estimate that the costs of meeting the 2020 climate targets are substantially raised by inconsistencies between different targets, relative to a very modest welfare loss under a theoretical least-cost policy.

There are very different jurisdictional trade-offs within the "Energy Trilemma". Germany has achieved its RES objectives and maintained security of supply at considerable domestic cost and increased CO_2 emissions from its nuclear phase-out—together with large spillover benefits for the rest of the world. German consumers have paid €125 billion in higher electricity bills for RES support schemes in the years between the 2000 *Renewable Energy Act* (*EEG*) up to 2015; it has been estimated that, over the next 20 years, overall costs

[5] The first EU Directive (2001/77/EC) set a target of 12% of gross inland energy consumption from renewables for the EU-15 by 2010—with an expectation that 22% of electricity would be from RES. All MSs set national indicative targets for the consumption of electricity produced from RES; for electricity, heating and cooling, these allowed for differences in RES potential, wealth and starting points across MSs.

may exceed €400 billion (Andor et al., 2017).[6] By contrast, the UK has set ambitious binding environmental targets but has emphasized achieving them at reasonable cost, and hence committed subsidies more cautiously than other countries (Anaya and Pollitt, 2016)—although it is currently at risk of missing its 2020 RES target and breaching the Levy Control Framework that limits RES subsidies (Pollitt, 2017).[7]

3. Impacts of renewables on EU electricity markets to date

Current market designs have achieved substantial learning gains across renewable technologies. Solar PV costs fell to less than one-tenth of their 1992 value in the 20 years thereafter; costs continue to fall as deployment rises, with an estimated learning rate of 17-22% (i.e., for every doubling of the installed *capacity*, unit costs fall by 17-22% in real terms).[8] The learning rate for onshore wind has been estimated at 7% and for offshore wind at 9% (King et al. 2015, Rubin et al. 2015). While there is considerable uncertainty about the precise degree of learning (Nordhaus, 2014; Farmer and Lefond, 2016), it is clear that cost reductions have been very large.[9]

In the short run, the addition of zero marginal cost RES shifts the supply curve to the right, causing the wholesale price and capacity utilization rates of coal- and gas-fired plant to fall. These effects, together with the demand shocks arising from the financial crisis, have substantially lowered the market capitalization of major European utilities. On some days, notably in Germany, high RES has led to *negative* prices as system operators (SOs) have sought to protect the grid from overloading due to higher-than-expected renewable supply.[10] This is a perverse consequence of only paying subsidies to RES provided they are dispatched, coupled with priority dispatch; it is avoided in Ireland, which prohibits negative price bidding by RES.

The magnitude of the ensuing price declines was not widely foreseen, neither by policymakers nor many of the energy companies themselves—who continued to invest in base-load fossil fuel power plants in anticipation of high wholesale prices and high capacity

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[6] There is an intense political debate over supporting the development of renewable power technologies in Germany that goes back to the 1980s. Its 1990 feed-in-law created a market space which supported the growth of a political network empowering renewables and the rapid deployment of RES after the Renewable Energy Acts (EEG 2000 and 2014).

[7] The *Global Apollo Programme* (King et al., 2015) calls for a global effort to combat climate change by supporting low carbon technologies such as renewables, to be achieved by sharing the support burden more equitably among as large a coalition of countries as possible. If successful, this would enhance the attractiveness of such programmes to each country, as their efforts would collectively have a higher pay-off.

[8] The higher figure comes from ITRPV (2016). This is consistent with Rubin et al. (2015) for one-factor models that attribute all cost reductions to deployment, while two-factor models that separately identify R&D lower this figure to 12%

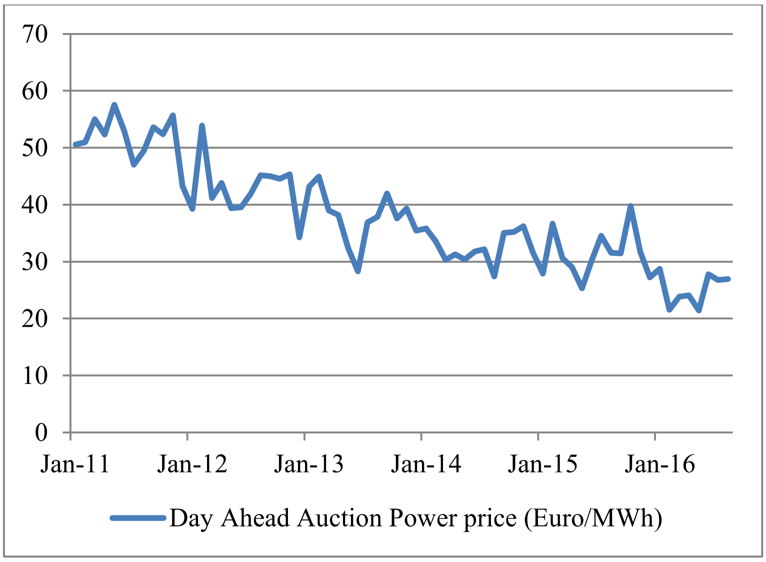
[9] Of course, how much of these cost reductions has been *caused* by EU policy, rather than actions of the rest of the world, is more difficult to estimate.

[10] The merit order effect is, in itself, not a market failure. It may simply be the efficient outcome of the workings of demand and supply in a competitive market where low marginal-cost technologies displace higher-cost rivals. However, when negative prices are a result of RES producers bidding to be dispatched to earn a subsidy, then it does become a market failure that distorts the wholesale price. See Würzburg et al. (2013) for an overview of studies of the merit-order effect in Germany.

utilization. Figure 1 illustrates the downward trend in Germany: over 5 years, wholesale prices have fallen by 50%. While other factors, such as falling fossil fuel and carbon prices also played a role, the estimates by Hirth (2016) suggest that almost half of the German electricity price decline can be attributed to the expansion of RES. These price reductions have essentially shifted rents from conventional electricity generators to consumers. Relatedly, major wholesale markets have also seen increased volatility of prices.

Over the longer run, this "merit order effect" can have other consequences. The downward pressure on wholesale prices undermines the investment incentives of fossil-fuel generators, which are in the medium term needed to provide firmness and flexibility to the system, thus potentially undermining security of supply (Praktiknjo and Erdmann, 2016). From the viewpoint of conventional generators, the "merit order effect" exacerbates the problem of missing money. More RES can also weaken the role of forward contracting in alleviating market power in wholesale electricity markets (Allaz and Vila, 1993)—and lead to higher prices in situations where the RES capacity factor is low due to strong intermittency (Ritz, 2016).

Figure 1: Wholesale power price in Germany (2011-2016 monthly average)



Source: Fraunhofer ISE

The impact of RES on market power is also mixed. In the Italian wholesale market (IPEX), market power was considerably weakened by RES competition during peak hours (over 2010 to 2013). Yet market power was exacerbated during some off-peak hours, in the absence of solar RES in particular zones, in which congestion yielded market splitting—and hence increased the ability of incumbent generators to raise prices (Bigerna et al., 2016). The situation may be worsened as more fossil-fuel plants close, further reducing capacity and competition in off-peak hours. As a result, market surveillance will need to evolve with RES penetration to distinguish between actual scarcity (which can be efficient) and abuse of market power.

High levels of intermittent renewables like wind and solar PV can create considerable problems for delivering reliable and secure electricity supply. The system requires firm replacement when they are not available (on windless nights), and it also requires inertia or other forms of frequency and voltage stabilization, that is, flexibility services to maintain quality of service. In Italy, for example, the rise of RES has resulted in an increase in critical load-following requirements for conventional plants, and with that a need for additional reserves and a risk of excessive intermittent priority-dispatch generation ("over-generation") in some hours, and a worsening of power quality (Clerici et al., 2015). Ancillary services are becoming increasingly scarce as conventional plant is displaced or exits because of inadequate revenue. System Operators and regulators are already increasingly seeking to ensure adequate flexibility services, e.g., on the island of Ireland through the DS3 program, and in GB through procuring additional fast frequency response.

The "integration costs" of intermittent solar and wind generation consist of all the economic costs they impose on the rest of the system: grid expansion, increased balancing services, and more flexible operation. At high RES penetration rates of 30-40%, system-level integration costs have been estimated at 25-35 €/MWh, including the substantial adverse impacts of lower and more variable capacity utilization on conventional generators (Hirth et al., 2015).[11] These estimates thus account for a large fraction of overall generation costs—and electricity prices.

In summary, the "1st generation market design" has accommodated RES shares to up to almost 30% of generation capacity, with a variety of impacts – some anticipated, others less so. Countries have adapted in different ways, depending on their generation mix and degree of interconnection to their neighbours. Yet the existing design is reaching the end of the road: it cannot adequately cope with the scale of Europe's COP21 climate commitments. Indeed, the EU's baseline projections suggest that current policies are not going to deliver the emissions reductions required (European Commission, 2016b).

What is needed is a market design that can support the delivery of the very high levels of renewables that will be required to meet the EU's climate goals. A key challenge lies in the uncertainty around future technologies and other market disruptors such as the rate of decline in distributed generation (DG) costs and consumer responses to smart metering.

4. General principles for electricity market design

This section sets out principles for improving electricity market design for a high-RES world. The economist's ideal market design is that of "complete markets" in which all products and services are efficiently priced by the marketplace (see Schweppe et al. 1988), to reflect their economic cost and value:

Time – electricity prices are determined at a very granular temporal level, e.g., second by second, now and for trade in the future, up to 10-30 years hence;

Space – prices vary at a granular spatial level – perhaps at each connection point in the network, reflecting how demand or costs differ across locations;

Carbon and other emissions – climate and air pollutant damages are priced at their social cost and thus incorporated into decision-making by companies.

[11] We note these integration costs are comprised of a mix of efficiency losses and transfers.

The EU's current Target Electricity Model is very incomplete in specifying the desirable changes; its market design fails on all of the above criteria: pricing is too coarse over time and space—and carbon emissions remain under-priced.[12]

The ideal is unattainable in practice but it provides a strong vision for a "2nd generation market design" to work towards. The desirability of more granular temporal and spatial prices applies even without reference to climate concerns as the need for more types and volumes of flexibility services increases. The EU's climate targets, if anything, strengthen the case for efficient market design given the need to price externalities as well as the case for minimizing overall system costs whilst achieving reliability.

The following principles are a high-level guide to shaping future policy. In practice, there are a variety of political and institutional constraints around market design. Important considerations include a widespread public preference for offshore wind over onshore installations (despite their higher costs) and the infeasibility of (new) nuclear generation in countries such as Germany. The principles explicitly allow for flexibility across different countries and in light of new information about technologies.

Principle 1: **Correct the market failures as close as possible to their source, relying on subsidiarity as much as possible.** Guided by the "principle of targeting" (Sandmo, 1975), market failures should be corrected at the national or EU-wide level. Climate change is inherently a global problem while RES targets are a way of equitably allocating the cost of RD&D across MSs to deliver learning benefits. Similarly, rules and standards for electricity trading and auction design benefit from an EU-wide approach. However, many details of market design can be left to MSs, subject to fair trading across borders.

Principle 2: **Allow for appropriate cross-country variation in market design across MSs rather than a one-size-fits-all solution.** Countries differ significantly in the quality and quantity of their resource endowments, the reserve capacity given existing generation assets, the stability of institutional and policy frameworks, the legacy interests protecting the *status quo*, and in the willingness of consumers to adjust their behaviour. Some countries will thus be able to push towards a better market design more strongly and/or quickly than others. Moreover, ensuring security of supply is inherently a local issue (albeit with ramifications across borders).

Principle 3: **Use price signals and regulated network tariffs to reflect the value of all electricity services and deliver the least system cost solution.** An efficient market design uses prices to signal the value of all electricity services provided (Schweppe et al., 1988). This has a long-run and a short-run dimension—ensuring the right location for investment (in renewables and other forms of generation) and an efficient dispatch once connected. This delivers the desired level of low-carbon electricity at least overall cost to consumers.

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[12] The most efficient policy would be an economy-wide carbon price set at the social cost of carbon—yet this does not appear feasible in the near term. In any case, a more ambitious future RES target should go hand-in-hand with a tightening of the ETS cap so as to preserve the carbon-pricing signal.

Principle 4: **Collect the difference between the regulated allowed revenue and efficient prices in the least distortionary way from final consumers.** This difference amounts to a levy to finance the natural monopoly akin to a tax. Good public finance principles imply that it should be targeted on final consumers rather than producers (such as generators or storage operators) and should be concentrated on inelastic demands (Diamond and Mirrlees, 1971). Since capacity demands are usually less elastic than energy demands, this generally favours capacity charges. As with taxation more generally, this is subject to fairness considerations.[13]

Principle 5: **Efficiently "de-risk" the financing of low-carbon investment as the electricity system becomes more capital-intensive.** A high-RES (and zero carbon) system is relatively more capital-intensive than the fossil-fuel system of the past. This enhances the importance of efficiently de-risking investment as far as possible within a stable regulatory framework that helps minimize the cost of capital. That involves balancing the allocation of risk to those best able to bear it (normally consumers) while retaining incentives to manage that risk (normally the owner of the plant).[14]

Principle 6: **Retain flexibility to respond to new information on the attractiveness of different low-carbon technologies**. Over time, new information will become available on the relative costs and benefits of different technologies that reduce emissions or enhance flexibility. Policy should create possibilities for such learning (e.g., via auctions) and experimentation, providing support for promising technologies where appropriate.

The analysis in the following section applies these principles to develop a set of policy recommendations for a future high-RES European electricity system.

5. Economic analysis of key market-design elements

Intermittent RES presents more significant challenges to balancing supply and demand than controllable generation. These challenges can be addressed in three ways: (1) demand and supply can be shifted over space (via interconnectors and transmission links) to provide local balance; (2) demand and supply can be shifted or over time (via storage); or (3) demand and supply can be balanced by invoking more flexible responses (e.g., through pricing).

This section presents economic analysis of six key mechanisms to address these challenges: interconnection and market integration, electricity storage, the design of RES support systems, distributed generation, efficient electricity pricing and long-term contracts.

[13] In general, the least distortionary way of collecting revenue is by individual lump-sum charges—but the information required makes these impractical. The case for charging final electricity consumers rather than collecting any shortfall through general taxation aligns with the benefit principle of taxation: beneficiaries should, to the extent that their benefit can be measured, make up any shortfall. Where the benefits are to the whole population (e.g., from mitigating climate change) there is a good case for financing their delivery from general taxation.

[14] The cost of risk increases as the square of the deviations from the average, so sharing risks across n identical participants reduces the *aggregate* cost of risk by a factor of n. Sharing electricity risks across millions of consumers for each of which it is a very small share of aggregate expenditure is thus much less costly than concentrating it on a company where it would be a high share of profit.

5.1. Benefits of cross-border integration & interconnection

The rise of intermittent RES generation further strengthens arguments for greater cross-border integration and raises the value of more interconnection within Europe. Interconnectors can deliver back-up power when intermittent RES are unavailable; by connecting areas with uncorrelated wind, they reduce the variability of that source of supply (due to intermittency) and dampen the volatility of power prices (Neuhoff et al., 2013). Sharing reserves across borders reduces the cost of ensuring reliability (DECC, 2013). Modern controllable DC interconnectors can also provide a number of flexibility services.

Ensuring that interconnectors are efficiently used and properly remunerated for all the services they can supply (as per Principle 3) both reduces the short-run cost of integrating renewables and increases the attractiveness of investing in additional interconnection (Newbery, 2016b). Better use of existing interconnectors and investment in new interconnector capacity increase the flexibility of the European system to exploit the natural advantages of the system as a whole (Newbery et al., 2016). These advantages include access to hydro reserves (such as those in Norway), large amounts of predictable solar power in Italy, Spain and Greece and the often negative correlation between wind speeds at locations up to one thousand miles apart (as weather fronts move across Europe) with the consequent ability to economize on back-up fossil fuel capacity. Real-time supply and demand balancing of *national* electricity systems with high RES shares is no longer sensible.

Denmark and Germany have already benefitted substantially from interconnection in their roles as leaders in RES deployment. For example, Denmark typically exports surplus night-time power to Norway; by reducing Norway's hydro use, this indirectly stores the surplus which can then be exported to Denmark in the day-time to meet any generation shortfalls. Much of its wind is exported in winter when co-generated district heating takes priority and delivers power to the grid.

Short-term benefits of cross-border integration

The benefits of market integration in the short-run derive from the more efficient use of the existing network, and specifically, of the interconnectors via market coupling. The price difference between adjacent price zones then reflects the value of capacity on that link, giving both a return to the link owner, and signaling where new interconnections might be profitable. Market coupling increases the use and value of interconnectors, also encouraging investment in new interconnectors over the longer haul.

Table 1 summarizes the EU-wide short-run benefits of market integration from fulfilling the Third Package (by using *existing* interconnections), as estimated by Newbery et al. (2016). The annual total of €3.9bn represents 2.5% of the 2012 value of total EU wholesale demand of €150 billion/yr. Table 1 breaks this total down into various sources, estimated usually from a sample of observations on individual interconnectors. The arbitrage benefits from day-ahead coupling are worth roughly one-quarter of the potential gains, with larger benefits from shared balancing resources and avoiding undesirable unscheduled flows. In a similar vein, Boffa et al. (2010) suggest that even relatively small improvements in interconnection can already bring about substantial benefits, and estimate annual gains of around €120mn from North-South market integration within the Italian electricity market.

Table 1: Potential short-run gains from EU-wide market integration

	ACER sample 2012			EU-28 estimate	
	€ million	NTC 2012	€'000/MWyr	€ million	Shares
Day-ahead coupling	300	22,000	13.6	1,010	26%
Intraday coupling		10,050	2.6 (MWh)	37	1%
Balancing	575	17,550	32.8	1,343	35%
Unscheduled flows	988	34,900	28.3	1,360	35%
Curtailment	19	26,075	0.7	130	3%
Total gains				3,880	100%

Note: The ACER sample is a subset of all interconnectors. The EU-28 estimate is scaled up using the values per MWyr derived from the sample. NTC is Net Transfer Capacity of the interconnectors, a measure of their usable size. The values for intra-day coupling are per MWh, curtailment is based on import and export flows together. Source: Newbery, Strbac and Viehoff (2016).

As intermittent RES generation increases, markets such as Norway and the Iberian Peninsula, are increasingly attractive for interconnection as their huge storage capacities (70TWh and 25TWh, respectively) allow them to act as a large batteries, evening out price fluctuations over days and weeks. Intermittent generation would otherwise require rapid changes in controllable output that would be reflected in very variable prices. Increasing interconnections to these markets would reduce this volatility but leave enough to create arbitrage opportunities and maintain the interconnector revenues needed for investment.

While increased interconnection brings substantial *overall* (net) benefits, these are not necessarily shared evenly across countries or regions (Spiecker et al., 2013), suggesting that the details of different MSs policies should differ (Principle 2). For example, while more efficient use of electricity will typically reduce overall carbon emissions, it may *raise* emissions at one end of the interconnector (Denny et al., 2011). A detailed cost-benefit analysis is therefore required to evaluate the desirability and efficiency of each interconnection.

Countries that are interconnected to the Continent through controllable DC links and are not part of the meshed Continental network have greater control over what happens in their markets without adversely impacting others and should thus be granted more flexibility, while those impacting neighbours may need more harmonization (Principle 2).

Longer-term interconnector benefits

The day-ahead arbitrage benefits can be estimated by looking at price differences across borders. ACER (2015, Figure 84) provides for a sample of 24 such links; for the top 15 interconnectors, this would be €68,000/MWyr. For a 1,000 MW link this gives revenue of €68 million/yr, capable of justifying substantial new investment. Moreover, these revenues represent only a fraction of the potential value of interconnections (around 25% in Table 1).

Newbery et al. (2016) estimate the benefits of integrating EU markets for a high-RES 2030 scenario. The potential benefits of sharing reserves, balancing, expanding interconnection where profitable, as well as allocating RES to the best resource locations, range from €13-40 billion per year for the EU as a whole. The wide range reflects uncertainty about future RES levels and costs as well as fuel and carbon prices. If only half the justified transmission is built, benefits fall by €4 billion/year; sharing reserves (rather than targeting self-sufficiency) raises benefits by €6 billion/year.

5.2. The medium-term potential of electric energy storage

While interconnection allows balancing over wider areas, storage offers the potential to balance over time. Indeed, existing pumped storage schemes were typically constructed to deal with inflexible supply, particularly nuclear, in the face of varying demand. Recent developments in battery technology, driven largely by laptop computers and mobile phones, has considerably lowered the cost of batteries, and the prospective demand for battery electric vehicles (EVs) offers hope that prices will continue to fall. This has led many to conclude that batteries will be a key element in addressing the growing problems of intermittent RES.

However, it is important to retain perspective, especially for the shorter term. Batteries are currently a *tiny* fraction of grid-scale energy storage overall, making up only 3 GWh or 0.1% of pumped storage. Even if their costs halved they remain extremely expensive. Optimistic forecasts for Tesla batteries in 2020 show their levelised running costs at $175/MWh, to which would be added the cost of the energy purchased (allowing for storage losses of 10%). This would require a very high value for the delivered energy to justify arbitrage. Battery storage, as such, is unlikely to be viable for time-shifting supply in current electricity markets (Staffell and Rustomji, 2016).

In practice, batteries are only justified for the other services they can offer—specifically, very fast frequency response and the ability to defer expensive network investments in certain places (Ruz and Pollitt, 2016). The main obstacles to their widespread economic use is that the fundamentals of electro-chemistry rule out dramatic breakthroughs in efficiency, while the cost of providing enough total storage capacity to buffer more than very short-term fluctuations (of less than an hour) is prohibitive—primarily because of the limited number of cycles of charge and discharge that a battery can experience before it degrades.

While mass-manufactured battery cells and packs may become significantly cheaper, grid-scale battery facilities will, likely, not fall as rapidly in cost. This is because of less technological progress in the other elements of grid-scale facility costs; for example, in distribution grid-scale lithium-battery storage, cell and pack costs amount to around 40% of overall facility costs (Sidhu et al., 2017). This suggests that dispatchable grid-scale batteries may not become as widespread as distributed behind-the-meter batteries (which will show up on the system in changed demand patterns).

Pumped Storage Plants (PSPs) represent the most established form of bulk electrical energy storage (EES) (Barbour et al., 2016). Newbery (2016c) estimates the total global PSP capacity at 2.9 TWh, of which 0.4 TWh for the EU. The merit of PSPs is their long life and low depreciation; their high capital cost and limited opportunities for capacity additions are serious limitations as their capital cost adds £40-£80/MWh to the cost of buying electricity given pumping losses of 25%. PSPs typically only earn a quarter of their revenue from arbitrage; the balance comes from flexibility services, for which they, like batteries, can be very valuable.

By comparison, hydro capacity was 979 GW worldwide in 2012, generating 3,288 TWh/year (or 16% of world electricity output), of which 173 GW is located in Europe and

144 GW in the EU together with Norway and Switzerland (EIA, 2016). Newbery (2016b) estimates its total hydro reserves at 2,144 TWh—equal to 2,700 times the global PSP capacity. Hydro can be used indirectly as storage by offsetting the intermittency in RES electricity production. Interconnecting EU markets to Norway (with its 70 TWh in dams) is the obvious route, subject to the corresponding cost-benefit analysis

The storage capacity of EVs can be estimated. If their share of the EU car fleet grows to 10% by 2025, there could be some 26 million EVs,[15] which, with 20 kWh/EV, would give 0.5 TWh—which is comparable to current PSP capacity (Newbery, 2016c). (Even at 100% EVs, this would yield "only" 5 TWh.) Moreover, while this may seem large by comparison with stand-alone batteries, only a part of it is (indirectly) accessible, in that timing of charges provides some demand shifting. However, the EV fleet may not be large enough to cost-effectively provide ancillary services until 2030 (Bishop et al., 2016).

The large-scale rollout of EVs will require incentives and/or controls over the time of charging since otherwise EV owners are likely to charge them at similar times (e.g. after work), which would put extra additional pressure on the electrical system. However, evidence suggests that EV owners are responsive to time-of-use charging so they can provide demand-side response (Newbery and Strbac, 2016). Other studies suggest that the business models around private EV participation in electricity markets will be challenging due to high payment expectations of vehicle owners for third-party access to their vehicles (Parsons et al., 2014).

As intermittency increases, the volume and value of EES will increase. However, EES is only one of several ways of providing flexibility—along with, e.g., interconnectors, flexible generation and demand side response (DSR)—and is often a very expensive, and thus unlikely to be a cost-minimizing solution (Principle 3). While superficially attractive, grid-scale battery storage remains too expensive to use beyond those projects where it has very high value-added, such as very fast frequency response and relieving network capacity (Pudjianto et al. 2014; Newbery, 2016c). By comparison, other forms of storage such as using PSPs and fossil fuel stocks remain relatively cheap.

That said, battery storage looks likely to play two main roles in the foreseeable future, which policy may support (Principle 6): first, batteries can defer upgrade investment in transmission and distribution systems by shaving peak use; second, varying charging rates of EVs may improve the management of power flows on the electricity network.

5.3. Designing more efficient RES support mechanisms

There have been many experiments with how to support RES while it has been more expensive than fossil generation (CEER, 2015). RES subsidies such as feed-in-tariffs (FiTs) that offer fixed prices for a period have successfully brought forth renewables in large quantities. However, in many cases, they have been very generous and pushed up system costs by distorting location decisions. Auctions offer a more attractive solution.

In addition to FiTs, some Member States have used a Premium FiT (PFiT, also known as Feed-In Premium or FIP), which pays a fixed premium to the current wholesale market

[15] There are projected to be 255 million cars in the EU by 2025; see http://www.theicct.org/sites/default/files/publications/ICCT_EU-pocketbook_2015.pdf

price, or a green certificate (Renewable Obligation Certificate, ROC) (Haas et al., 2011; CEER, 2015, Table 5).[16] The first type usually offers priority dispatch and places such obligations on the System Operator (SO), the latter two options usually place the marketing and balancing obligation on the RES generator. In 2013, FiTs accounted for about 58% of supported output, green certificates for 26% and PFiTs for 16%.[17] PFiTs are the EU's currently preferred option.

Auctions for RES support used to date have been very competitive, in line with Principle 6. For example, the results of the UK's auctions since 2014 suggest that these undercut the administrative prices offered by governments by a significant margin (Newbery, 2016a). This is supported by international experience in competitive tendering for solar energy, which has seen steep declines in procurement costs of both solar and wind installations (IEA, 2016). More use of auctions for pre-determined volumes of RES also has the advantage of controlling the overall amount of subsidy that governments commit to.

Auctions can and should be portioned into different technologies according to their relative maturity (for example, mature technologies such as onshore wind and solar PV in one auction and less mature technologies such as offshore wind in another). Clearing prices across these auctions will likely differ, and indeed this is what happened in the UK renewables support auction in February 2015.[18] They can be held regularly to encourage the supply chain; the capacity to be procured should adjust over time in line with learning about the cost evolution of different technologies. High-cost mature technologies will naturally be displaced by lower-cost alternatives, and less mature technologies should only be pursued while their prospects of becoming competitive justify the additional support.

We also suggest the extension of the use of auctions that are specifically aimed at promoting smaller scale RES projects. California has had a particularly successful experience with regular auctions (RAM) by individual distribution companies to procure 3-20 MW facilities around the distribution system. These auctions have included valuation of some of system integration costs and benefits in ranking the winning bidders in the auctions.[19]

If carbon prices move towards reflecting social costs, the remaining market failure associated with RES is the learning benefit, which arises from their design, manufacturing and installation (rather than the subsequent operation of the plant). Guided by Principle 1, this suggests that subsidies should be directed towards capacity rather than output, as has largely been the case across MSs to date.[20] An attractive variant used in China (Steinhilber, 2016) is to specify a FiT for a fixed number of MWh/MW capacity—e.g., 30,000 MWh/MW for a wind turbine, which is in effect a capacity support, as total lifetime subsidy does not depend on the output in any individual hour, which is therefore valued at the spot price.

[16] The value of a ROC is determined by the demand for and supply of these certificates, and is then added to the wholesale price. The demand is an obligation placed on retailers for a specified fraction of their sales, the supply is proportional to metered RES output.
[17] Figures based on CEER (2015, Annex 9).
[18] See NAO (2016) on the use of auctions by government to procure renewables.
[19] See Anaya and Pollitt (2015).
[20] If carbon remains underpriced and a MS is unwilling to impose a carbon price floor, then a possible "second-best" remedy is an additional subsidy to zero-carbon power, set at the average carbon intensity of fossil generation times the shortfall in the carbon price (below the social cost of carbon), which would be reduced) over time as the carbon-price shortfalls declines.

Future policy could therefore better target support on capacity (MWs) by offering an *auction-determined* payment per MWh for a fixed number of MWh/MW capacity (in addition to revenues from wholesale and other markets). This would de-risk the investment by making the payment stream predictable (Principle 5) and hence making it more suitable to be bond-financed. It would also encourage the best locations to be exploited first while not distorting the bids of renewable generators in the energy and ancillary services market. It would avoid the current situation where RES generators will bid negative prices in the wholesale market, up to the value of their lost per MWh subsidy.[21] As the share of RES rises on the system, this would be a way of ensuring that RES, once built, participated on equal and cost-reflective terms with conventional generation—in the spirit of Principle 3.

The wind and the sun vary over time and space and so will the cost per MWh from these sources. But to that cost must be added the transmission and balancing costs. Distant wind farms may have higher capacity factors but they incur considerably higher transmission costs—and it is that total cost that matters.[22] In the case of a FiT or PFiT, if the support price is set high enough to even encourage the least-favoured location, then it will over-reward those in favoured locations. This raises the cost of procuring a given amount of capacity investment (and RES learning benefits).

By contrast, if RES is supported per MWh/MW of capacity, rather than per MWh of output delivered, there is less inducement to locate in distant locations in response to a higher incentive per MWh. That has the benefit that it does not over-reward RES in favourable locations.[23] With locational pricing or zonal pricing with bidding zones based on structural network congestion, it also discourages excessive connection in constrained locations.[24] This would make better use of the existing network, and reduce the effect of current subsidies in exaggerating power flows when the network is congested. Assuming that a plant delivers at least the specified number of MWh, the only remaining (minor) distortion towards windier but less efficient locations is earning the subsidy more rapidly.

Understanding locational distortions due to feed-in-tariffs

A simple example illustrates how most existing RES support schemes lead to inefficient location decisions *even with nodal pricing*. Suppose that the nodal price in a distant windy location is €20/MWh (averaged over hours of wind generation) while it is €40/MWh near a major demand centre. The windy location has a capacity factor of 3,000 hrs/yr (i.e. produces 3,000 MWh/MW capacity) while the demand centre has a wind capacity factor of 2,000

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[21] Output payments make it worth bidding a negative price to be dispatched up to the amount of the premium (less any variable operating expenditure, OPEX), and this can distort the merit order, as it is costless to disconnect wind and PV, in contrast to disconnecting inflexible nuclear and fossil plants that are costly to restart.

[22] The value of power at any time and place does not depend on its source (fossil, nuclear or renewable), but the marginal cost of delivering the power to that place should reflect transmission constraints and losses (which would be assured by nodal pricing).

[23] While the discussion here relates to location within a country, there is a wider problem that current rules make it hard for any MS to locate RES in more favourable foreign locations and gain credit for meeting its target.

[24] A potential countervailing factor is the widespread public preference against wind installations that are located onshore, for example, in proximity to densely populated areas.

hrs/yr. So the value of the windy location is €60,000/MWyr and at the demand centre is €80,000/MWyr and so more valuable. If a wind investor receives a FiT of €80/MWh in both locations, then it would choose to locate in the windy place – where it produces more output but less value to society.

A PFiTs responds to local wholesale prices; it is less distorting than a FiT—but the premium element still creates a distortion. If wind is paid a PFiT, say with a premium of €40/MWh, then the windy farm earns €(20+40) x 3,000 = €180,000/MWyr and the demand-centred farm earns €(40+40) x 2,000 = €160,000/MWyr, so incentives still point to the wrong location. If the demand centre instead had 2,500 windy hours, the FiT would still favour the windy location. But the PFiT would now earn €60 x 2,500 = €150,000/MWyr in the windy location, less than the €160,000/MWyr at the centre, and so would locate in the right place.

5.4. Impacts of the move towards distributed generation

Distributed generation (DG) has been a major trend in the connection of RES in Europe. Governments have favoured small-scale renewables with more generous subsidies and this seems likely to continue. DG represents electric power generation within distribution networks or on the customer side of the network.[25] It is a leading example of the decentralization of the electricity markets.

DG consists of small-scale technologies often situated near homes and businesses where electricity is used, offering an alternative to large-scale centralized generation and potentially reducing line losses. It also offers electricity consumers the prospect of "self-sufficiency" which may be of intrinsic value to small (often household) consumers (partly since it provides tax-free returns on investment by reducing post-tax expenditure on energy). DG can be built more quickly than new central power systems, and can eliminate the cost of installing new transmission lines. Many forms of DG are cleaner than current conventional power, and should be able to provide ancillary services, and can contribute to security of supply if consumers switch to it during stress periods (Alanne and Saari, 2006; Cossent et al., 2011; Ruggiero et al., 2015).

However, DG has drawbacks. It can be technically challenging to efficiently integrate the increasing number of small generation units in an electricity system that up to now has been centralised, integrated and planned. A major problem to date has been the lack of visibility of DG to the authority charged with measuring capacity adequacy. DG, particularly solar PV, may cause voltage instability throughout the grid (Pepermans et al., 2005; Shah et al., 2012),[26] impacting power quality. Last but not least, the unit costs of small wind and solar PV are typically higher than for larger grid-scale installations.

DG can reduce losses and the need for system capacity upgrades, so the shift to DG over time could in some cases tend to reduce the size of the distribution system, thus also reducing overall system costs. But this effect does not look likely to be very material in most of Europe (Pollitt and Strielkowski, 2016).

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[25] In Anglo-American countries it is often called "embedded generation", in Europe and Asia "decentralized generation" or "distributed energy", while some prefer "small-scale generation".

[26] The "50.2 Hz" problem in Germany is a salutary example, see e.g. http://www.modernpowersystems.com/features/featuredealing-with-the-50.2-hz-problem/

DG with battery systems can lead to the possibility of grid-defection, reducing fixed network cost contributions from those customers and giving rise to a “utility death-spiral” (Athawale and Felder, 2016). This seems unlikely in Europe since most prosumers need access the network for “export” and prosumers still need “import” capability; having enough own battery storage to last through the depth of the winter is not currently an option, even in southern Europe.

Yet the possibility of large-scale network defection exists—and with it, there are risks to the viability of some poorly designed network business/regulatory models. System cost comparisons between on-grid and off-grid supply depend on fossil fuel prices, energy subsidy charging regimes (often recovered via electricity bills) and the way in which network fixed costs are recovered from consumers (see Pollitt, 2016). Some consumers might find it desirable and profitable to defect from the network, even though the true economic cost of remaining grid-connected is lower.

The combination of a household with PV, a battery and an EV might in the future offer a grid defection opportunity in sunny parts of Europe. While this will be appealing to some households and could enhance security of supply, it is unclear if it would be efficient from the viewpoint of the whole economy. If this does begin to happen, regulators would sensibly take steps to ensure that such households are not being effectively subsidised to disconnect or undercharged for options to reconnect to the grid—in line with Principle 3.

Charging mechanisms for DG and distortions from net metering

A considerable fraction of RES is of modest scale and locates on distribution networks, while roof-top PV is usually behind the meter of the household (although it may be separately metered). “Net metering” arises when the meter only measures gross consumption less the amount generated on the premises, usually without distinguishing times and hence different values for importing and exporting power. Distribution Network Operators (DNOs) are often under different ownership from the grid, and pay to connect to the grid, in turn recovering that cost from customers. This often leads to DNOs paying an embedded benefit to DG to the extent that it reduces the charges paid to the grid operator.

Most regulated networks use tariffs to recover their *average* costs, which can be much higher than marginal costs—particularly in a mature grid with low demand growth. Worse, if the grid has to invest heavily to deliver distant wind energy, and these costs are recovered across all DNOs, the difference between average and marginal cost can (and has in GB) become very large. Where the DNO pays an embedded benefit to DG for reducing power taken from the grid the excess of the average over marginal transmission cost gives a highly distortionary subsidy to generation connecting to distribution networks rather than transmission networks. It is therefore important for regulators (who are tasked with protecting consumer interests, often with specific duties to protect poor and vulnerable customers) to compute the efficient tariffs (moderated to take into account their equity effects) tariffs that impact location and operating decisions (Principle 3), and target the recovery of any shortfall on final consumers (Principle 4) in the least distorting way possible (e.g. by the size of their connection, or their specified maximum demand, or in peak winter hours).[27]

The efficient subsidy to confront DG would be the *marginal* avoided cost of grid reinforcement *less* the marginal cost of distribution reinforcement required; this might be negative, i.e., an additional subsidy. Applying this principle, households with PV would be paid the appropriate support for PV but pay for the full network costs of meeting their consumption. Such households will still use the network when the sun is not shining (and the peak is likely to be on dark winter evenings). Yet they usually pay the network charges per kWh, so under "net metering" (charges only on net electricity consumption, i.e., consumption less PV output) they avoid costs while enjoying the benefits of reliable access to power.

These existing charging mechanisms for DG have been leading to substantial wealth transfers between different customer groups in countries with high domestic RES penetration and high distribution system costs. Solar PV consumers have lower metered consumption due to their own production. This significantly reduces their share of the per kWh costs of the distribution system. As revenue cap regulation of the distribution charges requires the same revenue to be collected as demand has fallen, per-unit charges have risen and the distribution of their payment between different types of households has changed.

Inspired by the methodology developed by Simshauser (2016), we derive the differences in network charge contributions between solar and non-solar residential consumers in Northern England. A difference of £33.50/year or around 6% of the typical bill (if metered import was reduced by 1200 kWh due to having PV in the presence of a 2.792p/kWh distribution charge) is what the retail companies pay to the DNO for a non-PV household compared to the households with solar PV. This effect is magnified by the retail tariff (where the unit charge is 14p/kWh, more than twice the pure energy cost). Households with solar PV are therefore benefitting from the current tariff scheme although their solar power generation does not seem to affect their overall peak consumption behavior and hence use of the grid. This effect is further exacerbated as the charges to fund the PV (and other RES) subsidies are levied on net metered consumption

DG should bear the costs it imposes on the network in a fair and politically acceptable fashion. Recent studies have shown that large inequities can arise quite quickly in some jurisdictions, for example, in Simshauser's (2016) analysis of PV uptake in South Queensland. The existing system favours those with DG—likely richer consumers—who do not bear the efficient or fair share of the total system distribution and transmission costs. More generally, domestic PV subsidies often have been generous in absolute terms and disproportionately taken up by richer households while higher electricity prices affect poorer households relatively more strongly.[28]

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[27] This accords with the principles of good public finance that revenue-raising taxes should not distort production decisions, as set out by Diamond and Mirrlees (1971). It is moderated to the extent that if the Government is not willing to take full responsibility for addressing poverty, the regulator may be charged to protect vulnerable consumers with e.g. lifeline rates that scale back fixed charges for the first kWh/month.

[28] In the UK, for example, CEPA and PB (2011, p.11) found that expected returns to the PV Feed-in-Tariff were the highest among a broad range of asset classes (with 5-8% post-tax real returns) while DECC (2012, p.12) reported that UK households in the top income decile were 16 times more likely

Consequently the apportionment of charges between fixed, per kW peak and per kWh use of system charges needs to be changed to be more cost-reflective—as well as finding ways of exempting at least poorer households from financing RES that is largely taken up by richer households. These hidden subsidies are becoming more significant as the direct subsidy to RES has been coming down. Some jurisdictions outside Europe, notably Hawaii and Arizona, have already altered their distribution charging regimes to address this problem (by moving away from per kWh import charging).[29]

5.5. Efficient pricing for dispatch and investment

In a low-RES world, demand is fairly predictable and mid-merit fossil fuel plants can easily be turned up and down to meet real-time changes in demand or network constraints. This cheap controllability meant the value of high-resolution prices (e.g., 5 minutes or less) was limited. Prices could be set for relatively long periods (30 minutes or an hour) and the System Operator (SO) could adjust output (reserves) and/or re-dispatch plant within these time windows and across wide areas (regional price zones).

Today both the need and the scope for much more granular and differentiated price signals are already increasing. The supply from intermittent renewables, particularly solar PV, varies significantly in real time and is not controllable like conventional generation. Demand is becoming increasingly flexible and the costs of sending differentiated price signals are falling, for example, because of smart metering. Increases in computing power suggest that it is possible to more quickly resolve prices to exploit smaller time windows and more geographical dispersion (Greve et al., 2016).

Despite its potential advantages, arising especially via Principles 1 and 3, nodal pricing is currently neither practiced in the EU nor is it encouraged by the Target Electricity Model (TEM). Classic results of Schweppe et al. (1988) and Hogan (1992) show that nodal pricing can achieve higher social welfare than less granular pricing approaches. Current EU short-run electricity prices are insufficiently granular to properly value flexibility, balancing markets within the EU are not yet coupled, and ancillary services remain poorly priced in most markets. Nonetheless, nodal pricing should at least be compatible with the TEM.

The use of short-time interval locational pricing has already spread across US power markets, together with wider areas managed by Independent System Operators (ISOs), but remains underutilized across Europe. In the pioneering region of PJM (in the Eastern US), locational marginal prices (LMP) which reflect the marginal value of electricity at each node are recomputed by the System Operation (SO) every five minutes.

Indeed, nodal pricing to reflect the locational value of renewables would complement a more efficient European RES support design. Given that much RES is currently paid independent of location, the network is inefficiently saturated in high-resource (wind or PV) areas. With nodal pricing, excessive location would depress local power prices and thus signal the need to locate subsequent renewables elsewhere. The geographic dispersion of DG

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to have private PV on their roof than households in bottom income decile. Neuhoff et al. (2013) find that poor households allocate twice as much of their expenditure to power and show the resulting distributional effects of German renewables support policies.

[29] See Pollitt and Strielkowski (2016) on Arizona and Hawaii Public Utilities Commission (2015).

suggests increasing benefits could be realized by pricing which reflects local congestion constraints and line losses and avoids the need for expensive re-dispatch.

Large-scale modelling estimates by Neuhoff et al. (2013) suggest large welfare gains from a shift to nodal pricing and market integration in a future high-RES world (relative to a market design with nationally-determined prices). These gains arise from a combination of better use of the network, cost savings from more efficient dispatch, and lower overall electricity prices. More generally, sharper supply and demand signals would also allow better price arbitrage between nodes and across interconnectors, and better use of storage.

A shift to nodal pricing does carry the risk of reducing market liquidity and increasing market power but to the extent that more granular prices more accurately reflect the value and cost of power, they are valuable to the system. Markets with nodal pricing tend to have sophisticated in-house market monitoring functions (such as the independent market monitoring function associated with PJM). More generally, such a shift would require adaptation of market players and institutions. However, the existence of better separation of transmission from the rest of the electricity system than in the US and stronger national regulatory authorities suggests it is possible for Europe to rise to such a regulatory challenge (see Strbac et al., 2014).

Moreover, the current reliance on some ancillary services markets, such as for frequency response, could be reduced (in line with Principle 1)—given that these markets exist in the first place to maintain supply in the absence of fully granular prices. Ancillary services markets themselves can also move from bilateral contracting to more real-time market-priced products. This would facilitate competition in ancillary services provision between conventional generators and new sources of flexibility services such as batteries and interconnectors.

It is possible to mix better nodal and zonal pricing to reflect how local network conditions vary across MSs (Principle 2). Zonal pricing is a less granular form of pricing than the locational marginal price, with a single market price inside a region (typically a country or state). The trade-off is that nodal pricing achieves more efficient dispatch while more broadly configured zonal pricing gives more trading liquidity. For countries in which binding constraints in the transmission system are rare and nodal prices are relatively similar, zonal pricing may be preferable given its greater liquidity for traders. Other countries, which have more serious transmission constraints or are affected by large and variable transit flows, can pursue more fine-grained pricing (LMP) within their own networks.[30]

The TEM aims to create price zones that reflect transmission constraints rather than country boundaries, but to date many countries choose not to subdivide their country into zones. Britain is a clear example where this should have happened at the Scottish border but does not; Norway, in contrast, has a reasonable number of separate price zones. Even in the absence of nodal pricing, transmission system charges can still be made locationally differentiated. Yet many EU countries still levy grid charges on consumers with no charges

[30] Markets with central dispatch seem to manage LMP, while those with self-dispatch, like most power exchanges, argue for the liquidity of zonal pricing (in which case transmission charging needs to be suitably locational). In GB, some have argued that balancing charges should be nodal, so that at least generators face the right prices for marginal output decisions.

for generation, so there is no spatial variation and thus no or very weak locational guidance for new investment.

The standard US hedging instrument for volatile nodal prices is a Transmission Congestion Contract for a fixed number of MW. Its strike price is set at the current best estimate of the nodal cost of injecting power at a particular location. For renewables, the contracts would need to reflect output patterns and de-rated capacity. If the generator injects more than the contracted amount, it receives the LMP for the extra amount; if less, it pays the excess up to the LMP. This hedges against the varying LMP while incentivizing the generator to take the LMP as the relevant price for deciding how to offer output (Hadsell and Shawky, 2009). It would also provide more certainty about future transmission charges and clearer locational guidance.[31]

5.6. Long-term contracting and risk management

As a result of their durability, generation investments are exposed to a variety of risks. This includes innovation reducing the cost of competing technologies, changes to future fuel prices, carbon prices and also those to energy policy—such as wholesale price caps, carbon price floors, or RES subsidies that collapse wholesale prices. The energy sector has always had to deal with challenges of geopolitics but increased concern over climate change and sustainability has created new policy risks that are difficult to hedge. This means that equity investors in the energy sector are required to bear new risks, which raises the cost of financing the investments needed to deliver sustainability.

These distortions have resulted in individual MSs introducing a plethora of policies. One is the increasing use of capacity mechanisms to support otherwise excessively risky and potentially commercially unattractive fossil fuel generation to be available to provide the system with the required firmness and flexibility. Another is the use of long-term contracts (or purchase contracts) to support nuclear power generation. A general problem of this patchwork of policies is that its complexity favours better-informed actors in the private sector over the governments who design them.

Recent examples such as the planned UK nuclear plant at Hinkley Point C suggest that offering long-term price contracts may be high-cost solution compared to other alternatives, e.g. cost-sharing in the procurement with an auction-determined price to operate the plant once commissioned. Governments often find it difficult to determine and negotiate the favourable contract terms (Taylor, 2016). Excessively long contract durations (e.g. 15 years for capacity contracts in GB) appear to reflect a lack of political faith in short-term energy and ancillary services markets to provide a firm basis for security of supply.

An overarching goal of a "2nd generation market design" should be to achieve a simpler, better and more predictable policy environment that strengthens the ability of the electricity market to deliver supply security even with a high share of RES. Indeed, the mechanisms discussed above—more market integration, more granular price signals, more efficient RES support—would themselves likely reduce the reliance on politically-backed

[31] While it may seem rather complicated, the TSO already has to consider the impact of new connections on the need for reinforcement; this just makes explicit the calculations that need to be done in any case.

long-term contracts. While an inefficient policy casts doubt on its own durability, efficient policies ought to command more credibility, provided they achieve political and public support.

Higher levels of RES have revealed the "missing money" problems of the current market design for conventional plant need to provide reserves and flexibility services. Given the current extent of both "missing money" and "missing markets", the least-cost option for procuring such plant as the system becomes tight is a capacity auction (following on from Principles 3 and 6). While reliant on government judgment of the type and amount of capacity to be procured, this uses competitive market forces to determine the price of such capacity (to be paid to generators available to provide it during stress hours).

The European policy discussion on capacity mechanisms is still evolving. Within the class of capacity auctions, reliability options (Cramton and Stoft, 2008) may be preferable to the capacity mechanisms currently used in GB, Italy, Spain and other parts of Europe. Reliability options (ROs) have been recently proposed for the single market of the island of Ireland (Irish Republic and Northern Ireland). They specify a price cap set somewhat above the variable cost of the most expensive generator; RO holders pay back any excess of the market price above the cap, while consumers are protected by the cap. Their merit is that the wholesale price can still rise to high levels, signaling the efficient scarcity value for trading over interconnectors and activating demand response measures.[32]

Efficient risk allocation for RES

Similar to the rise in the importance of risk management for conventional generators following the reforms of the 1990s, RES will need to enhance its risk-management capabilities in a more market-based future world.

In addition to the output risk due to fluctuations in the wind or sun, there are two principal kinds of risk facing RES. The first is the balancing risk that arises because output is still uncertain when it is contracted for sale. Renewables becoming balance-responsible parties would require them to predict their availability at the time of contracting (year or month ahead) or submitting offers into EUPHEMIA day ahead or intra-day. Over a year, prediction errors might roughly average out and so RES is equally likely to be short or long in the balancing market. If prices are higher when the market is short then RES will likely under-contract and spill any surpluses into the balancing market (at a slight penalty overall). This risk, given its predictability over time should be contractible with third parties, usually with a larger generating utility.[33]

The second risk arises in support mechanisms, such as PFiTs and the capacity auctions suggested above, that link revenue to the wholesale price. These are likely to be positively correlated with overall economic activity and fuel prices. Yet retailers face no greater risk buying from RES than conventional generators, so should be willing to offer

[32] DG COMP has recently expressed a preference for ROs over capacity payments as they are thought to create the least disturbance to trading partners, as well as considerable hostility to the holding of strategic reserves except to address very short-run capacity shortages (European Commission, 2016a).

[33] This is supported by the estimates of Gowrisankaran et al. (2016) that the non-perfect forecastability of intermittency accounts for less than 5% of the overall social costs of solar PV (in Arizona, USA)—while intermittency itself accounts for more than 30% (in the absence of storage).

similar contracts to both. Indeed, large integrated utilities already offer long-term power purchase agreements (PPAs), which are essentially fixed-price contracts with a risk premium.

The remaining risk facing RES is its own output risk. Averaged over a run of years, this is likely to be modest (even if daily and monthly fluctuations are large) and only weakly correlated with the stock market—and so does not lead to a significantly higher required return from equity investors. In sum, efficiently managed, the remaining risks to RES may well be modest—but the point is that they need to be managed.

In the future, RES may thus face greater transaction costs arising from such increased risk management in a more market-based world.[34] The costs of trading 24-7, while continuously monitoring weather forecasts and optimizing positions, would be significant relative to the size of the average wind farm. This would benefit from aggregators taking on that task (Principle 5). In Spain, the system operator takes an active role in managing wind output; system operators would be well-placed to also help aggregate and manage risk.[35]

6. Concluding remarks

Rather than rehearsing the above arguments, we conclude by offering some broader reflections on the future high-RES world and policy design within it. A broader implication of our proposal to shift RES support to being based on capacity, is that the EU's RES targets themselves may also better be specified in terms of the capacity share of renewables (not their output share). This capacity share would have to be suitably de-rated, to ensure comparability across different types of RES generation—as well as a cost-efficient overall RES portfolio.

While increased interconnection brings substantial benefits to the high-RES system as a whole, the allocation of the costs and benefits of the interconnector between the two parties remains a challenge. Its beneficiaries are consumers in high-price regions and producers in low-price regions, together with the broad benefits of greater supply security, and lower system cost. Ensuring that interconnector owners are remunerated for *all* the services they provide would go some way to resolve this problem, provided other tariffs are set at efficient levels. Reallocating the shared costs of the interconnectors in proportion to those who benefit might also assist with a fairer allocation of the total benefit.

For grid-scale batteries, a major question is whether those batteries that make sense from a system viewpoint can find a viable business model. A battery provides multiple sources of value to the system (e.g., deferral of transmission and distribution upgrades, reserve capacity, frequency response services). This requires monetization of multiple revenue streams, which are currently variously regulated and market-based. Many of the sources of value of a grid-scale storage facility are local and subject to detailed power flow modeling; hence their valuation and subsequent contract design remains challenging across Europe. Viable business models may require a reconsideration of who can own and operate grid and distribution-scale batteries, given that current EU unbundling rules restrict the ability of network companies to own and operate such facilities. Improved network models

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[34] RES and conventional generation are increasingly becoming integrated under the same roof within an incumbent electricity company—which opens up additional risk-management considerations.
[35] See http://www.ree.es/en/press-office/infographs-and-maps/control-centre-of-renewable-energies-%28cecre%29

combined with real-time monitoring and the development of standard contracts offer the prospect of reduced transaction costs—but will likely require considerable investment and experimentation to realize their potential.

Distributed generation, in combination with batteries, may pose even more difficult payment allocation problems. Then richer customers with batteries will be able to actually reduce their use of the network, making it inevitable that either poorer customers pay more or tariffs will need reform to require higher fixed charges and time-varying energy charges closer to the wholesale level. Batteries with DG will clearly expose any arbitrage opportunities within the existing charging methodologies for both power and network use; as we have argued, it is important that these reflect value differences, not incidental cross-subsidies arising from poor tariff design.

Future emphasis could shift to mobilizing funds at the EU level to support RD&D of immature but promising technologies. Some estimates suggest that the financial support of major EU countries to RES deployment has exceeded that to R&D by a factor of over 100 (Zachmann et al., 2014, Figure 2) while the social returns to R&D have been estimated to be higher than to deployment returns (Jamasb and Koehler, 2007). This mobilization could perhaps be funded by MS contributions proportional to GDP or energy consumption.

A radically different electricity market design?

Over the long run, how to genuinely decentralize investment decisions around the quantity and type of generation to the private sector remains a key design problem for all electricity markets wishing to decarbonize. From 1990 to the mid 2000s, Europe successfully created a competitive wholesale market that privatized decision-making and risk management around new generation. Since then, governments have re-emerged as the major driving force behind the choice of the level and technology of investment.

A radically different future design may emerge via experimentation and the evolution of new technologies. A genuine market in low-carbon electricity may require a degree of financial and ownership integration between retailers and generators that is very different from the today's high degree of separation. It may also require very different contractual relationships between electricity consumers and retailers, which ensure the financing of long-term investments at reasonable cost and reflect the more distributed nature of generation. The ability and willingness of governments to let the private sector deliver such solutions will vary. This suggests the emergence of wider variation in the degree of government control of the electricity sector than was established by the single market project in the mid-2000s.

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