Market Design for Long-Distance Trade in Renewable Electricity

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ABSTRACT

While the 2009 EU Renewables Directive allows countries to purchase some of their obligation from another member state, no country has yet done so, preferring to invest locally even where load factors are very low. If countries specialised in renewables most suited to their own endowments and expanded international trade, we estimate that system costs in 2030 could be reduced by 5%, or €15 billion a year, after allowing for the costs of extra transmission capacity, peaking generation and balancing operations needed to maintain electrical feasibility.

Significant barriers must be overcome to unlock these savings. Countries that produce more renewable power should be compensated for the extra cost through tradable certificates, while those that buy from abroad will want to know that the power can be imported when needed. Financial Transmission Rights could offer companies investing abroad confidence that the power can be delivered to their consumers. They would hedge short-term fluctuations in prices and operate much more flexibly than the existing system of physical point-to-point rights on interconnectors. Using FTRs to generate revenue for transmission expansion could produce perverse incentives to under-invest and raise their prices, so revenues from FTRs should instead be offset against payments under the existing ENTSO-E compensation scheme for transit flows. FTRs could also facilitate cross-border participation in capacity markets, which are likely to be needed to reduce risks for the extra peaking plants required.

Keywords: Renewable Generator Integration, Transmission Investments, Financial Transmission Rights, Cross-Border Compensation

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1. INTRODUCTION

Europe has adopted ambitious targets for renewable energy: 20% of all its energy consumption in 2020, and 27% in 2030. Meeting these will imply a significant expansion in the amount of wind and solar generation across Europe. The output obtained from a given investment in capacity depends strongly on where that capacity is located, since wind speeds and solar insolation vary significantly across Europe. Given that both technologies are still relatively expensive, the advantages of deploying them mainly in areas with good potentials, in order to minimise the capital cost per unit of renewable output, ought to be clear.

If renewable output in many regions of Europe is thus dominated by either wind *or* solar capacity, it is likely to vary more over time than with a more diverse mix. This will exacerbate the well-known problems of intermittency, and steps must be taken to deal with this. One option is to

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build spare capacity to act as a back-up for times when the renewable generators are not running; an alternative is to use transmission links to other countries to get the benefits of diversity.

Europe is building a Single Electricity Market, which should facilitate international trade in renewable energy. The aims of this paper are to estimate the benefits of using international trade in renewable energy to allow more renewables to be deployed in areas with higher resources, and to assess the challenges involved. We use an engineering model of the European power system (WeSIM) to calculate the amounts of transmission capacity and peaking power stations needed to allow a secure, optimal, dispatch in two scenarios. One is based on a national deployment of wind and solar power, as in (Booz, 2013); the other has the same amounts of wind and solar output (in TWh over the year) but obtains them from less capacity, concentrated in areas with greater resource.

We find that it is possible to save 73 GW of wind capacity (16%) and 16 GW of solar capacity (8%) by deploying them in more suitable areas. This would bring a saving of €14.7 billion a year in 2030 (in 2012 prices): €18.9 billion gross savings offset by €4.2 billion additional costs to deal with greater intermittency. This is made up of €0.9 billion in extra fuel and operating costs, €0.3 billion in extra peaking capacity and €3 billion in additional transmission.

Despite the extra investment, the transmission lines between regions are frequently congested, even within countries, suggesting that market-splitting will be required inside countries alongside market coupling between them. Peaking generators will have very low average load factors, and if they depended on market prices to cover all their costs, their profits would be volatile, reacting to each year's weather. A cross-border capacity market might be a suitable way to reduce their risks and to share the burden of paying for these stations, although it might be hard to reconcile this kind of sharing with the natural desire to have "reliable" local generators available when system conditions are tight. We also find that while the overall savings from coordinating renewables are worth about 5% of the cost of generation and transmission, some countries are likely to lose, unless a carefully-designed renewable certificate trading scheme provides transfers to those building additional high-cost capacity.

If countries are to obtain a significant proportion of their renewable electricity from schemes outside their borders, they are likely to want confidence that this power can actually be consumed by the people paying for it. We show that a system of Financial Transmission Rights could offer this reassurance, and would be more flexible in practice than relying on the link-by-link physical rights that have demonstrated electricity trading in Europe to date.

The next section discusses the background to our work. Section 3 describes the model and its data, and section 4 presents the results. We discuss some of the implications for market design in section 5, and offer summary conclusions in section 6.

2. BACKGROUND

The principle of trade based on comparative advantage goes back to Ricardo, and applying it to either the electricity industry or to environmental problems is hardly a new idea. Countries have traded power across borders for decades, and Nord Pool has had a formal international wholesale market since 1996. Even before Nord Pool was established, the hydro-based systems in Norway and Sweden would tend to import power from Denmark and Germany in dry years and export it when they had plenty of water. While the availability of hydroelectricity varies from year to year, wind outputs vary from hour to hour. Denmark was the first European country to source a high proportion of its electricity from wind, and duly exported more electricity (or imported less) in hours with above-average wind output, compared to the monthly norm for that time of day. This allowed it to deal with the intermittency of wind output at a relatively modest cost (Green and Vasilakos, 2012).

The traditional approach to environmental regulation involved setting standards for every source of pollution and perhaps allowing them to vary if different sources faced different costs of clean-up; the newer approach of environmental markets can allow polluters to meet an overall cap on pollution in an efficient manner by trading. The US Acid Rain Program was an inspiration for the EU Emissions Trading Scheme (EU ETS), which has succeeded in keeping Europe's carbon emissions down to the level agreed by its governments. Unfortunately, the EU ETS has not been able to maintain a price at a sufficient level to encourage investment in low-carbon generation.[1] Achieving the EU's targets for renewable energy therefore requires direct intervention, mainly in the form of national feed-in tariffs or tradable green certificate schemes.

When the European Commission set national targets for renewable energy in 2009, it was aware that Member States differed in their renewable resources and the extent to which these had already been exploited. The starting point for these targets was therefore to *increase* the share of renewable energy in each country by the same amount, although those numbers were immediately adjusted to require richer countries to do more and the poorer ones to do less. The Directive also allowed a country with a demanding target, relative to its renewable resources, to develop joint projects with another country (inside or outside the EU) and share the renewable energy produced or simply to use a statistical transfer from another country that had over-achieved its target. These mechanisms are similar to the Clean Development Mechanism (CDM), established to allow companies and governments from industrialised countries to offset some of their carbon emissions by supporting projects in developing countries. As of March 2015, nearly 8,000 CDM projects with potential emissions reductions of 8 GT of carbon dioxide by 2020 had been registered (UNFCCC, 2015).

In contrast, almost all the proposals for cooperation under the EU Renewables Directive are still hypothetical (Klessmann et al. 2014). One reason for this is that most EU countries seem to prefer schemes within their borders which have a greater prospect of creating "green jobs" than those further afield;[2] getting voters to pay for an expensive power station in another EU country does not appeal to most politicians. Even if the principle can be agreed, Söderholm (2008) shows that a number of practical problems had to be solved to create the rare cross-border tradable green certificate market between Sweden and Norway (which is, of course, outside the EU but covered by many EU Internal Market rules).

The lack of practical progress has not deterred academics from studying the gains that might be achieved from greater coordination across Europe. Aune et al (2012) estimate that using an EU-wide certificate trading scheme would save 70% of the cost of implementing a 20% renewable energy target, measured in terms of economic welfare. They point out that while certificate trading could equalise the marginal cost of renewable production, the marginal value of electricity

1. In the first phase of the market (2005–7) this was due to the over-allocation of permits; from the autumn of 2008 onwards, it was due to economic recession reducing the level of business as usual emissions and therefore making it very easy to achieve targets that might have been demanding, had Europe continued to grow as predicted when those targets were set. It should also be said that if the targets for renewable generation are raised after emissions limits are set, and those limits are not adjusted to reflect this, the level of emissions allowed per MWh of conventional generation will be higher, allowing coal-fired stations to crowd out gas (Böhringer and Rosendahl, 2010). Europe set its emissions and renewables targets at the same time and should have been able to avoid this trap.

2. In fact, the number of jobs created by renewable generation, net of those that would have been required in a conventional alternative, is likely to be limited (Blyth et al, 2014).

consumption will vary (inefficiently) between countries if they have different national targets for the share of renewable energy. This is because a higher national target implies that the cost of a larger number of certificates have to be added to the price of each unit of electricity, and different targets will produce different prices, even if the marginal cost of power is the same. Unteutsch and Lindenberger (2014) calculate lower savings (41–45%) from coordination while reaching a 55% renewables target by 2030, using the more common metric of system costs (and ignoring the knock-on welfare effects from higher prices). This is worth between €57bn and €73bn over a ten-year period; Booz et al (2013) find savings of €15–30 billion *per year* by 2030.

The European Commission (2015) points out the importance of increasing interconnection. Its target is that every member state should have cross-border transmission equal to at least 10% of its installed generation capacity. Zachmann (2013) points out that the gains from increasing interconnection are particularly significant when countries with high shares of renewables can co-ordinate the back-up capacity needed, but also discusses the barriers to this coordination. Saguan and Meeus (2014) use a stylised model to predict that some national planners may have an incentive to build less transmission than would be optimal for Europe as a whole. Our main simulations assume that neither national self-interest nor local opposition to new lines prevents transmission from expanding optimally.

3. MODELLING AND DATA

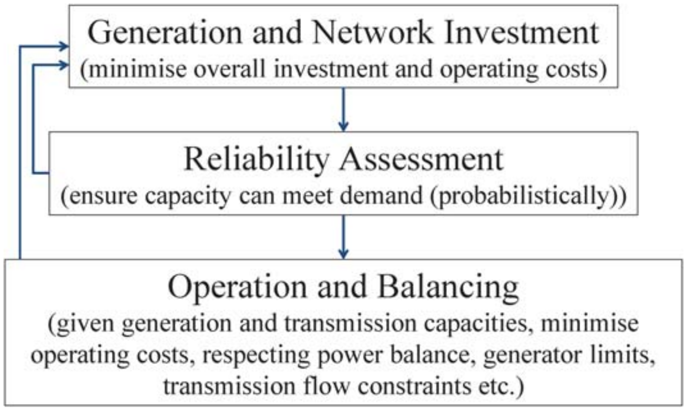
We combine three different models to simulate the impact of better coordinating the deployment of renewable generators across Europe. The main power system simulations are performed on WeSIM, a detailed model of the European power system that takes a scenario for the deployment of power stations across Europe and then builds transmission and peaking plant in an optimal way to ensure that the system can be dispatched to meet demand. The renewable output data are taken from two specialised models, for wind and solar outputs respectively. We model two scenarios, one based on the European Commission's Energy Roadmap 2050 in which most countries choose to deploy both wind and solar plants to meet renewable generation targets, whatever their resource, and a second which rebalances wind and solar capacity towards regions with better resources. Wind generators are therefore concentrated in countries around the Atlantic and the North Sea, and solar generators towards the south of Europe.

3.1 Whole-electricity System Investment Model (WeSIM)

WeSIM (formerly DSIM) is a detailed electricity systems model that co-optimises long-term investment and short-term operation decisions across generation, transmission and distribution systems. The model considers several time horizons: long-term investment, also optimising capacity margins to meet security of supply requirements; hourly dispatch of generation, storage and demand-side response; and real-time balancing of supply and demand on a second-by-second basis, including allocation of frequency response and reserve, and the impact of inertia effects. It also covers different assets in the electricity system: generation assets (from large-scale to distributed small-scale), transmission networks (national and interconnections), and local distribution networks operating at various voltage levels.

The objective function is to minimise the overall system investment and operating costs, across the time horizon of a snapshot year. The investment cost includes the (annualised) capital cost of new peaking generating and storage units, new interconnection capacity, and the reinforce-

Figure 1: Overview of the WeSIM model



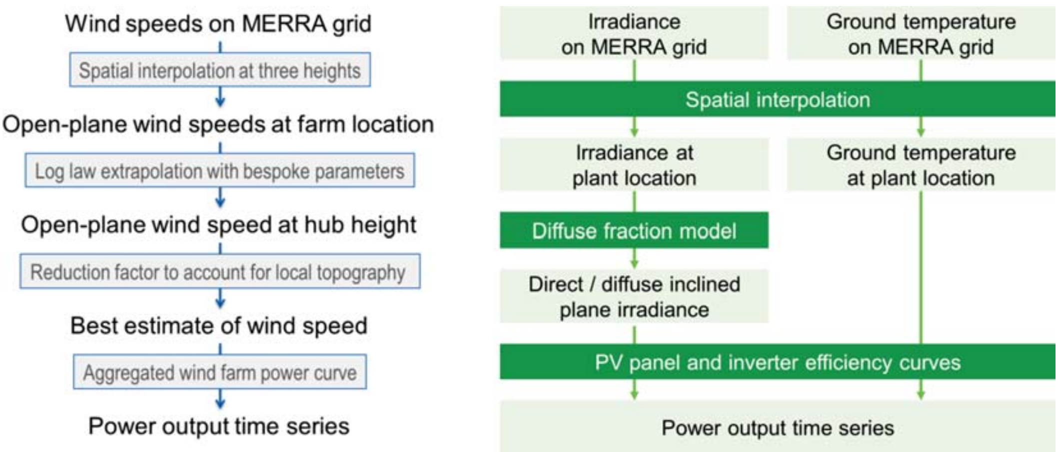
ment of transmission networks. System operating cost consists of the annual generation operating cost and the cost of energy not served (load-shedding).

Generators' operating costs consist of start-up costs, no-load cost per hour of operation and variable costs per MWh generated, and are determined by fuel and carbon prices and thermal efficiency. The cost minimisation is subject to a set of operating constraints which reflect the dynamic physical limits of system components and the need for secure operation. These include power balance, operating reserve and frequency response, generator-specific operating windows (minimum stable generation, ramping, up- and down-time), power flows on transmission and distribution lines, and security standards (through the loss of load expectation). Security constraints ensure that there is sufficient generating capacity in the system to supply the demand with a given level of security taking into account the long-term reliability of generating plants. The cost of providing response or reserve is not modelled explicitly; however the efficiency losses of generators running part-loaded due to response and reserve provision are modelled and therefore the cost of providing these ancillary services is taken into account.

WeSIM is formulated as a large-scale Mixed Integer Linear Programming optimisation problem and solved using FICO Xpress. The output of the model provides investment decisions in the network and peaking capacity, storage devices, hourly generation dispatch and allocation of response and reserve, demand response scheduling, investment and operating costs, and locational electricity market (energy, capacity, and ancillary service) prices for each region which are obtained from the Lagrangian multipliers of the respective constraints in the WeSIM formulation. Figure 1 gives an overview of the model; further technical detail can be found in Strbac *et al.* (2012) and Pudjianto *et al.* (2013, 2014).

Some European countries have well-known attitudes towards particular generation technologies. France has favoured nuclear power since the 1970s, whereas Germany is now phasing out its nuclear stations. It would be hard to reflect these differences within a fully optimising model of investment in generation, except via binding constraints that would make the model fully optimising in name only. WeSIM takes an alternative approach, which is to accept a scenario for generation capacities as an input and then build the optimal set of additional transmission lines and peaking plants to make that scenario work in practice. In this study, the model divides Europe into

Figure 2: Overview of the renewable resource models used to produce hourly power output time series for wind (left) and solar (right)



76 regions connected by 104 (actual or potential) transmission lines. It simulates 11 types of power station[3] on an hourly timescale.

3.2 Wind and Solar Output Models

The hourly profile of output from wind and solar farms was simulated using the *Virtual Wind Farm* and *Global Solar Energy Estimator* models respectively (Staffell and Green, 2014, 2015; Pfenninger and Keirstead, 2015). As summarised in Figure 2, these models take weather data from NASA and use physics-based models of wind turbines and solar panels to convert them to time series of power output. Further details on the methodology of each model and their validation can be found in the references above.

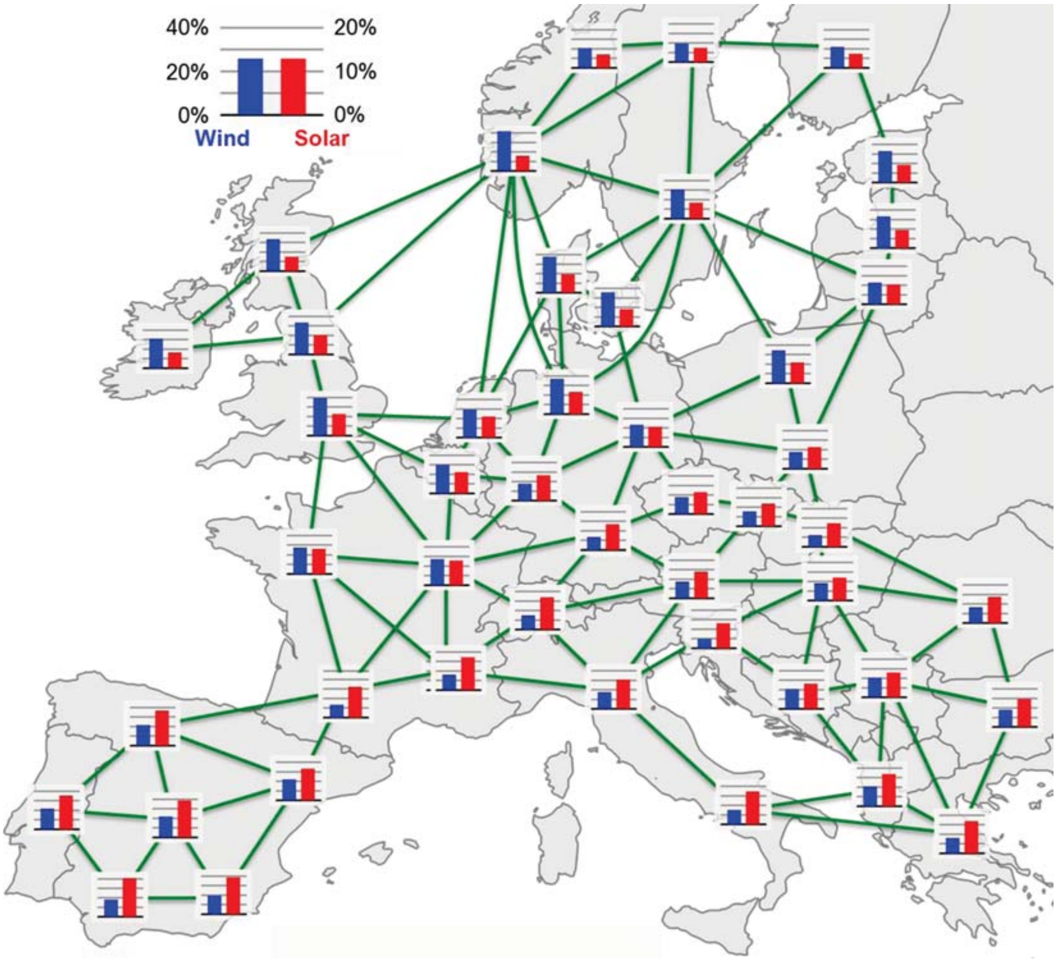
NASA's MERRA reanalysis (Rienecker, 2011) provides wind speeds and solar irradiance data at hourly resolution on a regular grid of ½° latitude and ⅔° longitude (approx. 55 by 44 km), giving around 2,900 onshore and 2,700 offshore locations across the extent of Europe.

There is no record of the location of every solar panel in Europe, so we assumed a uniform distribution of panels over space, with the capacity installed at each point proportional to the annual output raised to the fourth power, to reflect the general trend that installations are biased towards the southern latitudes within a given country. Time series for solar output were simulated for each grid point from 1995 to 2014 and were aggregated to national or regional level.

We used The Wind Power database (Pierrot, 2015) to give the location, height and installed turbine model for every wind farm that was existing or under construction as of January 2015, and for larger offshore farms that are in planning (predominantly in the North Sea and Baltic Sea). The wind speeds were adjusted within each country so that national average capacity factors for the existing fleets were aligned to historic statistics derived from EuroStat and ENTSO-E. This yielded capacity factors in the region of 35–42% for some regions of Britain, Denmark and Norway due

3. These are coal, gas, oil (peaking), nuclear, hydro with reservoir, hydro run of river, pumped storage hydro, biomass, geothermal, wind and PV.

Figure 3: The annual average capacity factor for wind and solar plants at each node in WeSIM, with lines showing the routes where transmission capacity exists or is added



to the high proportion of large offshore farms. Time series of output from each farm were simulated from 1995 to 2014, and aggregated together within each WeSIM region.

The average capacity factors for wind and solar are plotted in Figure 3. They are weakly anti-correlated (R = –0.49), and the simple averages across Europe (not weighted by capacity) were 25.0% for wind and 12.7% for solar, equivalent to 2,188 and 1,108 full-load running hours per year.

3.3 Cost, Demand and Plant data

We take our demand and cost data from Booz (2013), which is itself based on the High Renewables scenario in the European Commission's (2011) Energy Roadmap 2050. This has a system-wide peak demand of 662 GW and total electricity consumption (including losses) of 3834 TWh, 22% greater than in 2013. The investment costs for wind generators are equal to €2,413/kW,

Table 1: Generation costs in 2012 Euros

	Fixed Cost (€/kW-year)	Average Variable Cost (€/MWh)			Fixed Cost (€/kW-year)
Coal conventional	180	61.83		Wind	204
Gas Conventional	80	68.83		PV	258
Nuclear	371	7.53		CSP	276
Oil Peaking	35	103.14		Geothermal	361
Biomass	64	14.21		Hydro	213
				Storage	213

Table 2: Thermal and Hydro Generation Capacity (GW)

Country / group	Coal	Gas	Nuclear	Hydro	Biomass & Geothermal	Peaking
Nordic Countries[1]	2.5	9.2	13.0	54.2	16.5	2.1
UK & Ireland	2.5	7.4	6.8	7.0	10.1	0.2
France & Benelux	5.9	8.7	45.3	30.5	10.9	5.3
Spain and Portugal	1.4	13.7	3.0	29.3	10.2	2.3
Germany	13.0	8.9	0.0	13.5	11.3	1.2
Alpine Countries[2]	4.7	4.7	10.5	40.8	4.1	0.5
Poland, Baltic states	5.5	7.2	5.3	5.8	5.1	0.4
Italy	4.3	16.1	0.0	21.7	10.9	7.4
Balkan Countries[3]	7.9	3.0	9.0	29.6	5.0	0.5
Total	47.8	78.9	92.8	232.4	84.0	20.0

[1] Denmark, Finland, Norway, Sweden
[2] Austria, Czech Rep., Slovakia, Slovenia, Switzerland
[3] Bulgaria, Greece, Hungary, Romania, former Yugoslav states

which is annuitised to €204/kW-year. PV plants cost €2,873/kW, annuitised to €258/kW-year and peaking plants cost €441/kW or €35/kW-year. Plant costs are shown in Table 1: most renewable generators have no variable costs.

We model two scenarios for the distribution of generation across Europe. Our National scenario is based on the High Renewables scenario in European Commission (2011). This includes 556 GW of existing thermal and hydro generation (shown in Table 2), 475 GW of wind power and 189 GW of solar capacity (shown in Table 3). The wind capacity has an average load factor of 25%, generating 1039 TWh over the course of our modelled year. The solar panels have an average load factor of 13% and generate 209 TWh over the year.

Our second scenario assumes the same targets for wind and solar output (in TWh over the year) but distributes the stations differently. There is more wind capacity in regions with high wind

Table 3: The Distribution of Intermittent Renewable Generation Capacity (GW)

Country / group	Solar Capacity		Wind Capacity	
	National	Coordinated	National	Coordinated
Nordic Countries	3.4	0.2	26.3	65.8
UK & Ireland	8.4	0.1	87.8	151.8
France & Benelux	27.1	20.6	98.7	47.4
Spain and Portugal	31.6	59.1	78.3	28.1
Germany	48.7	21.8	119.1	80.0
Alpine Countries	6.9	0.6	9.2	3.3
Poland, Baltic states	7.7	0.0	8.7	1.2
Italy	40.1	58.4	26.9	14.9
Balkan Countries	14.6	12.1	19.9	9.8
Total	188.5	173.0	475.1	402.3

speeds, and less in calmer areas. Similarly, solar capacity is moved south towards countries with a high solar incidence. This allows us to obtain the same amount of energy from significantly less capacity—PV capacity falls by 8% and wind by 15%. Table 3 shows the distribution of capacity in the two scenarios. This Coordinated scenario has not been formally optimised, and so it is possible that further redistribution could bring additional benefits.

The regions which gain wind capacity in the Coordinated scenario typically have access to good offshore resources—around 80% of the capacity in Scandinavia and the British Isles, which see strong increases, is offshore, compared to 32–45% in Germany and France, where capacity declines modestly. The remaining regions have only onshore capacity, which declines significantly.

Our starting point for transmission is that 96,500 GW-km of transmission exist in each scenario; more is added by WeSIM if cost-effective or necessary to ensure demand is met. There are 15 potential corridors which have no capacity installed at the starting point. The cost of building or reinforcing overland transmission lines is route-specific, based on the terrain involved, and varies between €0.73 and €1.27 million per GW-km in the base case, with the data given in Pudjianto *et al.* (2014). Sub-sea lines are assumed to cost €1.8 million per GW-km.

Given the two distributions of renewable capacity, we model three pairs of scenarios. In the base case, the hourly demands are fixed, while in a second pair it is possible to move up to 10% of demand by up to 24 hours, using a combination of energy storage and demand response. Our third scenario examines the sensitivity of our results to the cost of building transmission, doubling the cost per MW-km on all routes. This could reflect higher investment costs or act as a proxy for the difficulty in overcoming political opposition to new lines.[4]

4. RESULTS

It should not be surprising that the cost of renewable generation is lower in the Coordinated scenario than in the National scenario; the two have been constructed to give the same level of

4. Lest this seem overstated, it is worth pointing out that if political opposition forces a company to build an underground line, this will cost ten times as much as an overhead line. Our base case numbers already include some allowance for this.

Table 4: Additional Peaking Capacity (GW)

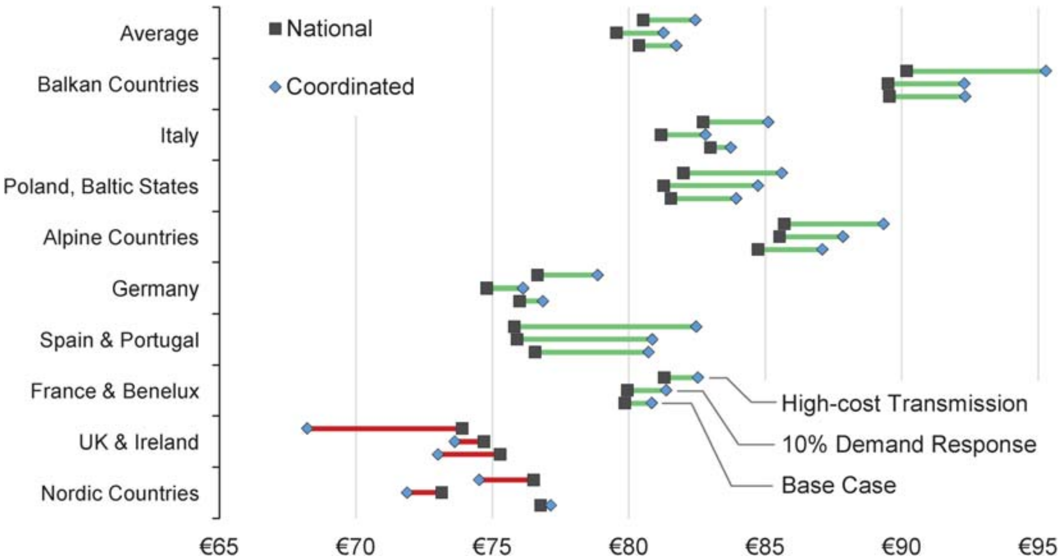
Country / group	Base Case		10% Demand Response		High-cost Transmission	
	National	Coord.	National	Coord.	National	Coord.
Nordic Countries	0.7	5.3	0.5	4.5	2.7	6.6
UK & Ireland	28.1	38.8	14.7	24.7	30.1	38.3
France & Benelux	45.9	30.4	33.1	23.9	57.4	44.7
Spain and Portugal	15.0	19.6	3.9	5.3	16.7	22.9
Germany	4.8	4.5	2.2	2.5	7.1	4.8
Alpine Countries	2.9	3.5	0.0	0.3	3.2	4.1
Poland, Baltic states	2.7	6.0	0.4	1.4	4.4	6.2
Italy	10.0	12.2	0.0	0.0	18.7	19.7
Balkan Countries	13.8	12.6	1.5	4.7	14.4	15.2
Total	124.0	132.9	56.2	67.3	154.5	162.4

renewable output but coordination requires significantly less capacity. The cost of the overall electricity system, however, depends on the pattern of renewable output over space and time. Spreading renewable generators across Europe makes their output more diverse and reduces the cost of dealing with intermittency; some of this diversity is lost in the Coordinated scenario. WeSIM copes with this by building additional transmission and peaking generators, while the output pattern of existing stations also changes. Table 4 shows that a large amount of additional peaking capacity is required in all six scenarios, and that this increases slightly (by 9-11GW) in the Coordinated scenario. Demand response and energy storage save much of this additional capacity (66–68 GW) but involve investment and operating costs of their own (not explicitly modelled here, but studied extensively in Strbac *et al.* (2012)). If transmission is more expensive (or difficult) and less is built, countries must be more self-sufficient and add more peaking capacity.

Many studies of the impact of renewables find strong effects on average prices, usually because they hold constant the level of conventional capacity. WeSIM adjusts the total level of capacity in response to the deployment of renewable stations, even though the amount of non-peaking plant is assumed to be constant, and this means that changing the distribution of renewable capacity might not affect average prices. Similarly, while increasing levels of demand response (and storage) might be expected to reduce peak (and hence average) prices, in some regions this is more than offset by the fall in peaking capacity installed. In practice, however, we find that most countries have higher time-weighted average prices in the Coordinated scenario, as shown in Figure 4. Denmark, Ireland and Great Britain have lower prices in all three variants of the Coordinated scenario, and Belgium, Norway and Sweden in one or two, all of which accompany a strong increase in wind capacity relative to the National scenario. The spread of national average prices, measured by the standard deviation across country time-weighted averages, is higher in the Coordinated scenarios. Making transmission capacity more expensive increases the differences between the Coordinated and the National scenario for most countries.

Many previous studies find that raising the amount of renewable generation in a country also increases the standard deviation of its prices. The total amount of renewable generation is constant across our scenarios and so we cannot test this hypothesis directly, but find no clear pattern

Figure 4: Time-weighted average prices, unweighted averages across regions (€/MWh)



between changes in the distribution of renewable output and the standard deviations of prices within countries. Demand response, however, does lead to a noticeable reduction in price volatility (around 40%), while more expensive transmission increases it by around 50%.

By concentrating renewables into specific areas, the Coordinated scenario does see a stronger merit order effect, whereby renewables depress wholesale prices with their output, and thus earn less than other generators (Sensfuß, 2008). Per kWh of output, wind receives 89% of the time-weighted price in the National scenario, falling to 85% in the Coordinated scenario. The strongest effect is seen in Ireland, where wind receives 75% and 70% respectively. The effect is less profound for solar, which earns 93% in the National and 90% in the Coordinated scenario; with the strongest effect being in southern Italy where PV receives 90%, declining to 86%. With more expensive transmission the merit order effect is stronger in all cases, but the additional penalty from coordination is no greater. Wind receives 82% of the time-weighted price in the National scenario, falling to 78% in the Coordinated scenario; while solar receives 83%, falling to 80%.

The number of zero- or negative-price hours is relatively unchanged with coordination, reducing in countries that would be allocated less wind capacity (particularly Portugal and Spain), and increasing in those that gain it (GB, Ireland and Denmark). Averaged over all nodes, there are 116 hours with zero prices in the National scenario, and 101 hours in the Coordinated scenario without demand response. The greater share of renewables in some regions (which would make negative prices more likely) is offset by additional transmission capacity. The presence of 10% responsive demand reduces the number of hours with zero prices by 26%, while doubling the cost of transmission increases it by 50%.

The total value of output from wind generators is €67.0bn in the National scenario, which falls 6% to €62.7bn in the Coordinated scenario. The value of solar output is almost unchanged between the scenarios at €14.3bn; possibly because solar capacity is less strongly concentrated than wind in the Coordinated scenario. Coordinated policies see the share of wind capacity held in the three largest nodes rise from 27% to 42%; whereas the share of solar in the top three nodes only rises from 32% to 37%.

Table 5: Statistics on electricity transmission across Europe

	Base Case		10% Demand Response		High-cost Transmission	
	National	Coord.	National	Coord.	National	Coord.
International flows (TWh)	810.2	1162.1	828.8	1169.1	849.5	1161.0
Mean line utilisation (%)	42%	47%	47%	54%	53%	55%
Mean proportion of congested hours	21%	27%	26%	34%	44%	44%
Transmission surplus (€ bn.)	3.67	5.83	3.17	5.31	5.20	8.65
Extra capacity built (GW-km)	37,173	58,091	32,510	49,305	25,638	41,853
Intra-country flows (TWh)	709.4	1087.9	719.0	1128.9	724.2	1103.5
Mean line utilisation (%)	30%	35%	33%	39%	35%	42%
Mean proportion of congested hours	11%	13%	12%	16%	24%	26%
Transmission surplus (€ bn.)	1.97	3.19	1.58	2.90	2.51	4.50
Extra capacity built (GW-km)	23,370	42,886	16,897	36,716	13,760	30,779

Despite this reduction in value, placing renewables where they work best has a profound effect on the amount of subsidy required; taken to be the gap between the revenue from energy sales from wind and solar (normalised per kW) and their annuitised cost. The average yield for wind rises from €138 to €154 per kW per year by coordinating policies, and for solar rises from €81 to €91 per kW per year. Compared to their assumed costs of €204 and €258 per kW-year respectively,[5] this reduces the total required subsidy from €33.0 to €20.9bn for wind, and from €34.0 to €28.8bn for solar—a combined saving of €12.1 billion, or €39 per household per year.

International trade in electricity rises significantly once investment in renewable generation is coordinated, as power flows can offset the reduction in diversity. Table 5 shows that cross-border trade rises by just over 40% and intra-national flows by over half in the base case. The flows are slightly greater in the presence of demand response, presumably offsetting the lower levels of peaking capacity available to manage intermittency. To allow this trade, €3.3 billion (annuitised) is spent on additional transmission in the National scenario, and €6.2 billion when renewables are coordinated; these figures decrease by about 10% with demand response. If we double the cost of new transmission lines (as a proxy for the cost of overcoming opposition to them, in extreme cases by building the lines underground), the amount of new capacity built falls by about one-third; the amount spent rises to €4.2 billion in the National scenario, and €8.8 billion in the Coordinated scenario. Despite the lower capacity, flows on both internal and international lines are actually higher in the National scenario than in either of the other cases. This is because of a rise in loop

5. It should be noted that for compatibility with previous works, these are 2012 cost numbers from (Booz, 2013). If more recent (and lower) cost numbers were used, the absolute amount of subsidy required would decrease. By construction, this would affect the gains from coordination by the same absolute amount within each pair of scenarios.

Table 6: Total cost of energy under each scenario by country grouping (€m)

Country / group	Base Case		10% Demand Response		High-cost Transmission	
	National	Coord.	National	Coord.	National	Coord.
Nordic Countries	22,864	22,077	23,175	22,144	23,890	23,439
UK & Ireland	34,623	36,357	33,567	35,338	35,999	39,380
France & Benelux	61,896	57,920	60,999	57,194	62,979	58,937
Spain and Portugal	40,547	41,221	40,045	40,577	41,415	42,206
Germany	61,252	51,814	60,581	51,069	62,425	52,864
Alpine Countries	19,789	17,966	19,918	18,115	20,181	18,522
Poland, Baltic states	15,840	14,212	15,433	13,817	16,090	14,609
Italy	38,733	40,763	38,195	40,068	39,184	41,369
Balkan Countries	26,173	24,688	25,755	24,314	26,853	25,605
Total	321,717	307,019	317,668	302,636	329,017	316,931

flows—with less transmission capacity available on the direct route between a region with a shortage of power and one with a surplus, the flows have to follow alternative routes that happen to have spare capacity at the right time. The regions on these transit paths thus see a rise in both imports and exports. There is also an increase of 9 TWh in the amount of wind constrained off because of transmission constraints. The flows in the Coordinated scenario are similar to those in the other cases, but still imply higher capacity utilisation.

The revenue that transmission operators earn from arbitrage between nodes increases by 60%, from €5.6bn in the National to €9.0bn in the Coordinated scenario in the base case. In both base case scenarios, 35% of this revenue goes to intra-country lines and 65% to cross-border lines. The international lines are more heavily used and are congested about twice as often as internal lines. Transmission revenues are slightly lower with demand side response, and higher when transmission is more expensive—the surpluses rise to €7.7bn in the National scenario and €13.1bn in the Coordinated one.

Table 6 presents the total system cost, defined for each country grouping as the annuitised costs of generation and transmission assets, the variable costs of production and of net imports (valued at local market prices), less half the surplus from transmission (which shares the gains from trade when prices differ at the two ends of a line).[6]

Coordination yields an EU-wide saving of €14.7bn per year, or €15bn if there is 10% demand-side response (which saves a further €4.3bn to €4.1bn). With more expensive transmission, the saving falls to €12.1 bn. These savings are not evenly spread among member states; Germany gains €9.4bn (15%) from coordination (in the base case) whereas the British Isles and Italy spend an additional €1.7 and €2.0bn respectively (5%). Furthermore, the savings are not homogenous within regions. For example, Denmark spends an extra 12%, Norway and Sweden save 2–4%, and

6. This is equivalent to using a split-savings rule, which sets the price for cross-border flows equal to the average of the prices at each end of the line.

Finland saves 15% through coordination, yielding a regional saving of 3%. The general trend is that countries with high wind or solar resource see more renewable capacity installed and thus incur higher costs under coordination. The costs presented in Table 6 deduct the market value of (net) electricity exports, but our assumed costs for wind and solar capacity are greater than the market value of the power they will produce. In other words, building renewable capacity and selling the power at market prices would be a loss-making activity.

It should be pointed out that as the costs of wind and solar generation are falling over time, future costs could well be lower than those assumed here, which implies that the savings from coordination would also be lower. If we assume a 20% reduction in the cost of wind power and a 50% reduction for solar PV, the annuitised cost of renewable capacity in the National scenarios would fall from €145.7bn to €126.8bn. The cost in the Coordinated scenarios would also be lower, falling from €102bn to €88.1bn, implying a saving of €13.9bn a year from coordination (before adjusting for other changes), compared to €18.9bn at our assumed prices. Coordination would still clearly be worthwhile, since operating and transmission costs only rise by €4bn to €7bn a year, but the net gains are smaller.

5. IMPLICATIONS FOR MARKET DESIGN

The coordination described above is unlikely to be politically feasible, however large the overall gains, if some countries would face significant losses. Countries that specifically buy renewable energy in order to reduce the cost of meeting their targets should expect to pay more than the market price for conventional energy. We find that a premium of between €9–15/MWh for wind energy and €100–115/MWh for PV would minimise the number of countries that lose from coordinated policies or the sum of their losses.[7] Even with this compensation, four or five countries would appear to lose from coordination. The premium needed for solar power is much higher than for wind, since the gap between the cost of solar power in the model and the prices at which it is exported is far higher than for wind energy. With the lower costs described at the end of the previous section, the loss-minimising premia fall to around €3/MWh for wind energy and €10/MWh for solar power.

With the costs we model, the premia required for PV and for wind are very different, and a single price would either deliver inadequate support for PV or excessive rents for wind farms. If countries simply had to acquire a given amount of "renewable electricity", then they would naturally be tempted to find wind farms rather than PV schemes to support. If the supply of wind farms in good locations is inadequate, countries might be tempted to develop their own poor-quality resources rather than to pay the costs of supporting PV power elsewhere, however good its relative resource quality. A banding design, which gives more certificates per MWh of PV power than for wind power, would be the best way to mitigate this problem—although choosing the relative number of certificates would inevitably be the subject of much lobbying. In the longer term, this problem may disappear if the costs of PV panels continue to fall until the point that solar electricity in good locations needs no more support than wind power.

Discussions about EU countries using international trade to meet their renewable targets often assume that they have to be physically able to import the electricity involved, even though the Clean Development Mechanism has no requirement to import a product. Green certificates that

7. The premia needed to minimise the sum of absolute losses differ from those that minimise the sum of losses as a percentage of each country's energy costs, and also lead to a slightly different group of losers.

were completely divorced from the delivery of electricity would be simpler to administer, but it might be argued that a certain proportion of the electricity actually consumed in each country must come from renewable sources. It is of course impossible to determine the exact source of the electrons consumed by any given consumer at a particular time, but it should be possible to allocate each unit of output to a single country. If this were done on an hour-by-hour basis, it would also be possible to require that the country buying renewable output also had sufficient transmission capacity to physically import it. This would be important if consumer-voters wanted to be sure that they were getting the "benefit" of the renewable power that they had paid for.[8] The traditional approach to securing capacity for imported power is to buy it along a "contract path", but this ignores the nature of uncontrollable electricity flows in a meshed transmission system. Physical transmission rights have been used on many European interconnectors but create poor incentives: a holder with market power in generation may wish to withhold the rights in order to restrict competition. The rules governing physical rights differ from the laws of physics in that flows in opposing directions cannot be netted off, making it likely that capacity would be under-utilised if power flows could only be scheduled by the holders of physical rights.

It would be far better to create Financial Transmission Rights (Hogan, 1992) that hedge price differences between two points without allowing the holder to distort the physical dispatch of power. FTRs have successfully been used in several US power markets for nearly two decades. If transmission owners receive the price difference between two points on the network when power is sent across a congested line, then this makes them the natural counter-parties for the FTRs—they exchange a risky flow of payments dependent on actual power flows and prices for an up-front payment. They can issue as many FTRs as they like (since the contracts are purely financial) but will only enjoy the benefit of the hedge as long as the net power flows implied by the entire set of FTRs is feasible. This should ensure that if a country only bought renewable power that was backed by an FTR, that power could actually be consumed in the country. Since FTRs that imply flows in different directions along a line can be netted off against each other, it is possible to issue more FTRs than unidirectional physical rights, which must be limited to the capacity of each line. A renewable project with an FTR need not worry if the price in its own region is low, since payments under the FTR will compensate for this.[9] This would allow electricity companies in one region to invest in renewable projects abroad, and know that their customers will be able to consume that electricity.

The revenues from FTRs (inter- and intra-national) are more than sufficient to pay for the cost of additional transmission capacity, but would in general have been even higher, had the additional capacity not been built. This can produce perverse incentives, particularly given the difficulties involved in securing planning consent to build new lines. The incentives might be improved if transmission companies also receive payments for transit flows under the ENTSO-E compensation scheme—the greater their capacity, the higher the flows and thus the compensation are likely to be. If the revenues from FTRs were actually deducted from these compensation payments, the scheme would then be revenue-neutral to actual price differences. This should remove the incentive to under-invest, although there may be other interactions which deserve further study.

8. The ability to import power hour-by-hour may be less important from the point of view of the underlying aims of renewable support: aiding technology development, cutting carbon emissions and even reducing dependence on imported fossil fuels, which all depend on the amount of capacity deployed or on generation over a longer period of time.

9. The cost of buying an FTR from a low-price to a high-price region, which therefore involves large payments, will reflect the expected value of those payments, however.

The expansion of renewable capacity requires a large amount of peaking capacity to back it up, and even more in the Coordinated scenario. We find that most of these stations have very low load factors, around 1% on average. While the theory of energy-only markets suggests that the optimal number of stations should be able to recover their costs, Joskow (2008) gives a number of reasons why this may not happen in practice, and the actual running times and revenues could vary significantly from year to year, depending on the weather. This is likely to imply a rather high cost of capital, at the very least. Capacity markets, or other payment schemes, can provide a hedge against the volatility of annual incomes and reduce peaking generators' cost of capital.

Imports can be critical in meeting demand at times of low renewable output within a country's borders; does this imply that capacity markets should be trans-national? This might give consumers (and politicians) more confidence that capacity on the other side of an interconnector would in fact be available when required, and also shares the burden of paying for it more widely. At the same time, organising a trans-national capacity market would be a complex task, and countries would have a natural tendency to want output from "their" generators to be used within their borders when system conditions were tight. Sharing peaking capacity could also involve the operational decision to share spinning reserves, but this would require some transmission capacity to be held back from energy transfers so that imports could increase rapidly when the need arose.

The current EU Target Model for electricity markets requires separate prices on each side of a major transmission constraint. Most European countries operate with a single price zone covering the entire country, and folk wisdom justifies this on the grounds that national transmission systems are stronger than interconnectors between countries. Table 5 shows that in our future scenarios, while the capacity utilisation for intra-country lines is lower than for interconnectors (on average), they are congested about as often. This suggests that many countries should prepare for zonal pricing within their borders; nodal pricing can give more accurate signals but is not suggested by the Target Model.

6. CONCLUSIONS

We have shown that Europe could save a significant amount of money—around €15bn a year—by better coordinating the deployment of renewable energy. This is about 5% of the annual cost of generation and transmission; if that seems small, it is in fact a similar amount to the welfare gains that Newbery and Pollitt (1997) estimated as a result of the privatisation and restructuring of the British Central Electricity Generating Board. In the absence of other policy interventions, however, it would create significant losses for some countries, and it seems unlikely that any transfer scheme based on standard prices for wind power and for solar power could entirely avoid creating some losers.

A bigger obstacle may be that most governments have preferred to subsidise renewables in their own countries, partly because of "green jobs" but also because they want to be sure that their consumers can actually access the electricity generated. A system of Financial Transmission Rights could provide this access. The rights can only be issued if the overall pattern of flows they imply is feasible (hence ensuring that consumers can access the power) and they also insure against price fluctuations between the source and consuming region.

The revenues from FTRs can help to pay for the additional transmission capacity that will be needed if Europe is to concentrate renewable generation in the most productive areas. However, relying on FTR revenues alone can give transmission companies perverse incentives to under-invest (even though the extra spending needed on transmission is much less than the cost saving in generation). It would be better to finance the transmission investment from the existing ENTSO-E scheme for compensating transit flows, but adjusting the payments under that scheme to net off the revenues each transmission company receives from selling FTRs. FTRs could also provide the framework through which generators in one country participate in another's capacity market: it is likely that these markets will be needed to reduce the risks faced by peaking generators. Allowing cross-border participation, but only if backed by an FTR, could make those markets more efficient. Many details remain to be worked out, not least the rules needed to ensure that the same capacity is not being simultaneously relied upon and expected to deliver in two separate markets. Using FTRs to facilitate the placing of renewable generators in the most productive areas could unlock large savings; the challenges are to agree the detailed rules and change the inward-looking behaviour that is currently raising Europe's electricity costs.

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