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.

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Executive Summary

While the 2009 EU Renewables Directive allows countries to purchase some of their obligation from another member state, no country has yet done so. Instead, the UK is investing in solar power and Italy in wind generation, despite pitifully low load factors. This paper considers the cost of this inefficient allocation, and mechanisms to allow a better policy that puts renewable generators where the best resources are.

We use a detailed engineering-economic model of the European power system, WeSIM, which finds the optimal amount of transmission capacity and peaking plant to make scenarios for renewable and conventional generation operationally feasible at least cost. In other words, it takes as given the differing attitudes of, say, France and Germany to nuclear power, but optimises the operation of those plants and the capacity of the transmission system to minimise the cost of delivering a secure supply of energy to consumers. We have high-quality renewable output simulations from specialised wind and solar models, which we use to consider the consequences of changing the distribution of renewable capacity across Europe. The model has 76 regions with 104 (actual or potential) transmission lines between them, and is simulated on an hourly timescale for a year of operation.

Our National scenario assumes 475 GW of wind power with an average load factor of 25% and 189 GW of solar PV with an average load factor of 13%. A Coordinated scenario obtains the same annual energy outputs from 402 GW of wind and 173 GW of solar PV, saving 15% and 8% of their capacity respectively. This cuts the cost of renewable generation by €19 billion a year in 2012 prices, although the wholesale prices calculated by the model do not reflect this. These prices are driven by the different amounts of peaking capacity added to ensure demand can normally be met, which caps the highest prices within each region at similar levels in each scenario, anchoring the average market price. The savings would instead be seen in the form of reduced subsidies that are paid by consumers on top of wholesale market prices.

To make either scenario feasible, additional transmission capacity is needed both within and between countries, but the Coordinated deployment of renewables requires an annuitised cost of €3 billion more than the National scenario. Concentrating renewable generators into a few regions means fluctuations in the weather lead to much greater changes in output than when they are spread more evenly across Europe, and transmission flows rise to offset these. The greater transmission capacity is more heavily utilised, but the proportion of hours in which lines are congested actually falls slightly. When the lines *are* congested, however, the price differences are greater in the Coordinated scenario.

These price differences (and congested lines) would expose companies importing renewable power to significant risks. A system of Financial Transmission Rights can hedge these risks by paying the difference in wholesale prices between an importing region and an exporting one. Depending on the market design in force, this either allows the company to pay transmission charges for moving power between regions based on nodal price differences, or to sell power at the generator's location and buy it back in the consumers' region, with any difference offset by an FTR payment. Large numbers of FTRs in different directions can be issued as long as the overall net flows are feasible, allowing for a greater volume of trade than with physical contracts for specific interconnectors, which are limited in volume to the capacity of the line in each direction.

We find that a large amount of peaking capacity will be required to offset fluctuations in renewable output, but that it will typically have a load factor of only 1%. Its energy market revenues will vary from year to year, implying significant risks and a relatively high cost of capital. Capacity markets could provide an alternative income stream to reduce those risks and hence the cost of capital. Cross-border participation in these markets is likely to be beneficial as long as system operators can be confident that the power could actually be delivered, which might be signalled by requiring the generator to hold an FTR for all the capacity it is selling.

Overall, the costs of extra transmission capacity (€3 billion a year), peaking generation capacity (€0.3 billion a year) and fuel and operating costs (€0.9 billion a year) offset less than a quarter of the savings in renewable generation costs, giving a net saving of €15 billion a year. That is about 5% of the projected cost of generation and transmission in Europe in 2030, and finding market mechanisms to unlock those savings is an important project.