A Green European Electricity Market: The role of cross-border trade

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In 2050, electricity demand in Europe is likely to be significantly higher than today with electrification of heat and transport, while the level of intermittent generation will also be much higher. The cost of meeting these challenges may be reduced through international cooperation, so that trade flows smooth out national imbalances between demand and generation. We use the Energy Transfer Reference Case (ETRC) model to discuss the size of the problem and the scale of transmission that might be required.

We also ask whether current market mechanisms can give the right incentives to generators, transmission companies and consumers in a world where many generators have very low marginal costs.

Introduction

The European Union has started on the path to decarbonisation, and many EU Member States have committed themselves to achieving a low-carbon energy system by 2050. One leading approach for doing this can be summed up as to decarbonise electricity generation and then to electrify heat and transport demands. This will be a challenge, given that significantly more final energy is currently used in heat and in transport than in the form of electricity. If there was no improvement in the efficiency with which delivered energy is transformed into heat and motion, the annual demand for electricity could increase by a factor of three or four.

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Providing this power from low-carbon sources would be a challenge, even if it could easily be produced exactly when and where it is needed. In practice, however, many renewable generators are intermittent and are best located where the resource they exploit (wind or sun) is strongest. Large-scale electricity storage is prohibitively expensive at present, except in hydro reservoirs, although research is taking place to reduce the cost of this. Another solution, available with current technology, is to move power from areas with a surplus to those with a shortage: this will require significant amounts of extra transmission capacity.

The aim of this paper is to examine how much transmission capacity is required to sensibly meet Europe's future demands for energy services, drawing on an open-source model, the Energy Transfer Reference Case (ETRC). ETRC starts with estimates of the energy services required in 2050 – heating degree days, million Euros of industrial production, person-kilometres and so on. The modeller then selects the proportion of each energy service to be met with a particular technology (vehicles might be fuelled by electricity, hydrogen or biofuels, for example). This allows daily demand profiles for electricity to be created, taking into account behavioural choices (how much vehicle charging is "smart").

Given these demand profiles, the modeller has to specify how they are to be met, creating portfolios of power stations in each of nine European regions, together with two in North Africa, potential sources of solar power. The output from wind and solar generators in each region depends on weather conditions and we have drawn on NASA's MERRA database to estimate hourly load factors for a portfolio of plants across each region. The transmission capacity between each region is also a key input to the model.

The output from controllable generators is optimised by the model, using a transmission-constrained merit order stack approach. That is, the demand across Europe is met from the stations with the lowest variable costs, as far as possible. If demand in one region is high, relative to the local low-cost generation capacity, this could result in imports that exceeded the capacity of the transmission lines, and so more output is needed from generators in that region. The hourly price in each region is set to equal the marginal cost of generation there. A region that is unable to export as much power as the Europe-wide demand would imply, given transmission constraints, will have lower prices as a signal to reduce its output. In most regions, hydro power is simply dispatched with a peak-shaving algorithm that releases water at the times of highest local demand. The large storage reservoirs in the Alps and the Nordic countries are dispatched alongside thermal power stations, with a shadow water value calculated to represent their opportunity cost of generation and ensure that they do not release more water than they have available over the year.

ETRC therefore calculates outputs, prices, costs and profits for generators and transmission owners across Europe. We use the model to calculate the cost of meeting energy demands in 2050 under the IEA's 2 degrees and 4 degrees scenarios, and to estimate the value of adding transmission capacity to facilitate a low-carbon power system. We concentrate in particular on the value of additional capacity between the Nordic countries and the UK, given that the latter is likely to develop a large amount of intermittent wind generation and the former have a large amount of storage hydro that could offset this intermittency. Norway and Sweden already provide this service to Denmark (Green and Vasilakos, 2012); do they have the capacity to help the UK as well?

We find that with sufficient transmission capacity, the European electricity system should be able to cope with volatile demands and intermittent production from renewable generators. Indeed, there is a risk that the price-smoothing effect of hydro generation could be transmitted throughout Europe, making it very difficult for conventional generators to recover their costs in an energy-only market.

Methods and Data

ETRC is an open-source model of the European energy system in 2050, built in excel and running VBA macros. A website is under development, which will contain the model and a full description including instructions to run it. The model is currently specified for nine multi-country regions within Europe and two in North Africa, listed in Table 1 and shown in Figure 1.

Figure 1: The regions within ETRC

Table 1: Regions within ETRC

Region	Countries	Region	Countries
British Isles	Ireland, UK	**Baltic**	Estonia, Latvia, Lithuania, Poland
France & Benelux	Belgium, France, Luxembourg, Netherlands	**Italy**	Italy
Iberia	Portugal, Spain	**Balkans**	Hungary, Romania, Moldova, Croatia, Bosnia, Serbia, Albania, Macedonia, Bulgaria, Greece
Nordic	Denmark, Finland, Norway, Sweden	**NW Africa**	Morocco, Algeria, Tunisia
Alps	Austria, Czech Republic, Slovak Republic, Slovenia, Switzerland	**NE Africa**	Libya, Egypt

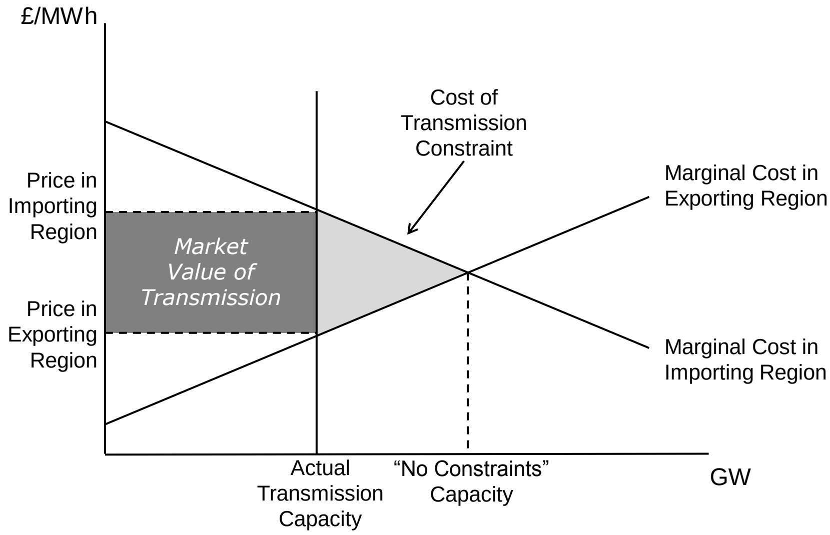
The first stage of the model requires the researcher to specify the drivers of demands for energy services, such as population, GDP and transport needs. It is also necessary to give the split between energy vectors for each energy service, and the level of efficiency improvements expected. This module will then calculate the final energy demands required to provide those energy services, and estimate hourly profiles for electricity demand. In a future development, the model will also calculate the daily profile for final gas demand; these can be combined with the demand for gas for electricity generation to give the overall demand for gas in each area.

The second stage requires the researcher to specify the amount of each major kind of generation capacity within each region. The transmission capacity on inter-region boundaries is also needed. The output from wind and solar plants is calculated using load factors from the virtual wind farm model (Staffell and Green, 2014) and the virtual solar model (Pfenninger and Staffell, 2014) developed at Imperial College. The output from hydro plants in most regions is allocated across hours with a peak-shaving algorithm to smooth the residual demand (net of wind, solar and this hydro output) as far as possible. Hydro output from two regions, the Nordic countries and the Alps, is not allocated in this way but as part of the main generation model, the third process in ETRC.

ETRC's generation model uses a merit order stack approach with transmission constraints to calculate the output from each technology in each region in every hour of the year. This minimises the cost of generation, and the marginal cost of the marginal technology is used as the price of power in each hour. The marginal cost of hydro generators in the Nordic countries and the Alps are equal to the shadow value of their water; this endogenously determines their place in the merit order to ensure that all of the available water (and no more) is used during the year's operation.

The model has a market-coupling algorithm which ensures that if part of the transmission capacity between two regions is unused, those regions will have the same marginal cost and hence market price. If the demands and capacities are such that the desired transmission flow exceeds the available transmission capacity, then the price of power will be higher in the importing area and lower in the area that is exporting power. This price difference represents the (variable) profit per unit that the owner of a "merchant interconnector" would make in that hour and is also equal to its social value. We also calculate the cost of transmission constraints as the difference between the total cost of generation, should there be no limits on transmission capacity, and the actual cost. These concepts are illustrated in Figure 2.

Figure 2: The value of transmission and cost of constraints



The energy services demands underlying the modelling reported here are based on the IEA 2 Degrees Scenario (IEA, 2012) which gives a least-cost vision of limiting global temperature rise to 2°C with an 80% certainty. Energy-related emissions are reduced by 50–60% by 2050 through decoupling energy demand from economic growth, extensive energy efficiency measures, and broad electrification of heat and transport (combined with hydrogen and biofuels).

The generation scenarios are derived from the ECF Roadmap 2050 (ECF, 2010) and IRENE40 project (hppt://www.irene-40.eu), considering the cost-optimal technology mix required to give an 80% emissions reduction from the electricity sector. This assumes large expansions of renewables (350 GW of wind and 490 GW of solar across Europe, ~60% renewable penetration), carbon capture and storage (fitted to 40% of the 470 GW fossil plant), and a small expansion of nuclear to 160 GW.

We use three underlying scenarios to calculate the value of transmission capacity in Europe. All share the same level and distribution of generation capacity, but they differ in the amount of inter-region transmission capacity.

- Scenario 1 has a total of 36 GW of cross-region capacity in its base case, assuming no growth over 2010 levels;
- Scenario 2 has 75 GW, based on ECF's scenario for 40% renewable penetration; and,
- Scenario 3 has 145 GW, based on ECF's 80% renewable scenario.

We also test the implications of increasing the amount of capacity between the Nordic countries and the British Isles within each scenario. The levels of generation capacity in Europe and in North Africa, and the variable cost for each type of thermal station, are shown in Table 2.

Table 2: Generation capacity in GW (common to all scenarios)

Type	**Variable Cost (£/MWh)**	**Capacity (GW)**	
		Europe	**North Africa**
Nuclear	9.77	157.4	0.0
Coal	48.73	99.2	1.1
Lignite	52.46	33.6	0.0
Gas CCGT	92.90	309.5	95.3
Gas OCGT	164.23	31.7	35.0
Gas Boiler	146.76	19.7	0.0
Oil	253.17	16.4	6.0
Biomass	68.87	42.2	8.6
Waste	68.87	22.1	0.0

Type	**Capacity (GW)**	
	Europe	**North Africa**
Geothermal	13.6	0.0
Hydro	219.4	8.5
Pumped Storage	102.1	0.9
Wind	353.7	76.7
Solar	485.3	159.0
Marine	6.6	0.0

Results and Discussion

As transmission capacity is added, it should become possible to make better use of the cheapest generation available. Table 3, below, shows this happening: the amount of generation from coal plant (most of which is fitted with carbon capture and storage) rises while that from gas falls. Gas has a higher variable cost than coal (assuming both are fitted with CCS) with the fuel and carbon prices we assume.

Some of the largest impacts are apparently seen in North Africa, which is able to reduce both its gas generation and the amount of renewable power that has to be spilled once the transmission links to Europe are strengthened. In practice, our scenarios probably place an excessive amount of renewable capacity in North Africa, unless the links to Europe are indeed strengthened, and even the high-capacity scenario 3 may be inadequate for the volume of renewable capacity there.

Table 3: Generation output (TWh)

	Scenario 1 36 GW transmission		Scenario 2 75 GW transmission		Scenario 3 145 GW transmission	
	Europe	**N Africa**	**Europe**	**N Africa**	**Europe**	**N Africa**
Nuclear	1102	0	1102	0	1103	0
Coal & Lignite	855	6	864	6	900	6
Waste & Biomass	368	44	378	47	384	49
Gas	869	705	909	646	896	607
Oil	0	13	0	7	0	5
Hydro	733	28	739	28	743	28
Wind	652	95	652	95	652	95
Solar	555	313	555	313	555	313
Spilled renewables	-5	-32	-2	-21	0	-15
Total	**5,130**	**1,173**	**5,196**	**1,121**	**5,233**	**1,088**

In contrast, the amount of renewable power that has to be spilled in Europe is relatively low. This could be because we assume that hydro capacity is allocated in a way that tries to minimise the impact of fluctuations in renewable output; however, we also assume that there are no transmission constraints within our regions. Given that these regions cross many national boundaries, and that there are some binding transmission constraints between windy and less windy regions even within countries (Sweden and the UK are both examples of this), ignoring these sub-regional constraints means that we will be understating the amount of energy that needs to be spilled. It should also be noted that some studies predicting that large amounts of renewable energy will be spilled are based on much higher levels of renewable capacity than we have assumed.

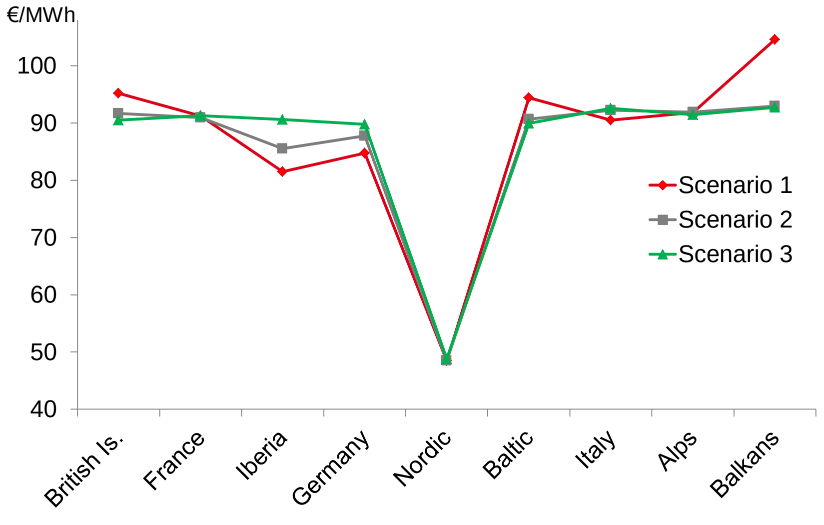
Table 4: The Value of Transmission (billion €)

	Scenario 1	**Scenario 2**	**Scenario 3**
Cost of generation	€253.3 bn.	€240.8 bn.	€234.3 bn.
Cost of transmission assets	€17 bn.	€50 bn.	€100 bn.

Table 4 shows the annual variable cost of generation in our three scenarios, and the estimated capital cost of the cross-region interconnectors. Starting with the lowest level of interconnection, €33 billion of investment brings annual cost savings of the order of €13 billion, a very high rate of return. The additional gains from a more developed grid are naturally decreasing, but at €6.5 billion a year for an investment of €50 billion, still offer an attractive return. Note that we have not considered the capital cost of generation, but this does not change between our scenarios.

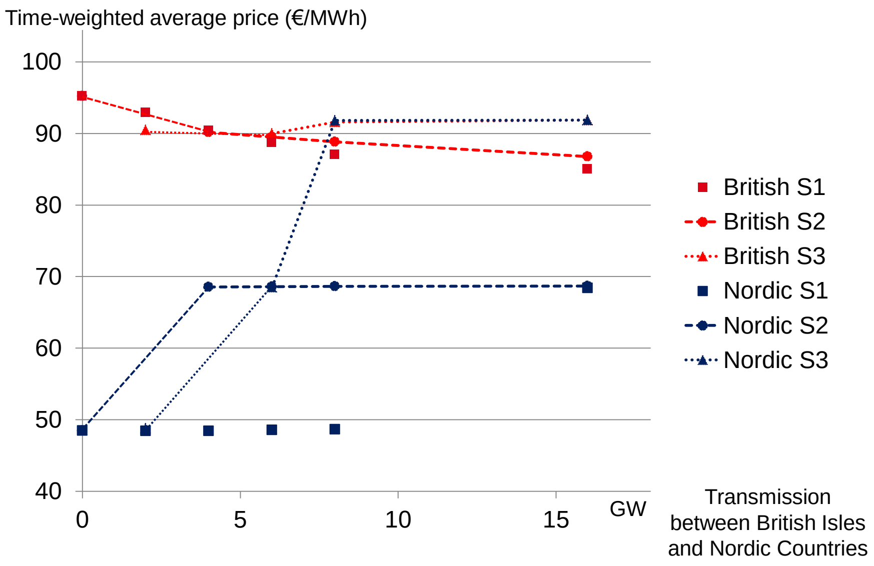
Figure 3 shows the time-weighted average prices in each European region. The lowest price is seen in the hydro-dominated Nordic region, and this is hardly changed by the level of transmission capacity across our three scenarios, implying that transmission constraints between the region and the rest of Europe remain binding for much of the time. We will shortly investigate the impact of building additional interconnector capacity between the British Isles and the Nordic region. The other regions within Europe have similar prices, but there is more dispersion in scenario 1, with little transmission, than when the inter-European links are strengthened. In particular, the Iberian Peninsula has its wholesale spot prices reduced by solar power from North Africa when the links to France are weak; as those links are strengthened, the spot prices tend to equalise. The Balkans and the British Isles, relatively isolated in the low transmission scenario, see higher prices that fall once their connections improve.

Figure 3: Time-weighted average prices



To further explore the implications of expanding transmission capacity, we consider the specific example of lines across the North Sea between the British Isles and the Nordic region. In each scenario, we expand the capacity in stages from zero (or the 2 GW which is already assumed in scenario 3) to 16 GW. The results are shown in Figure 4.

Figure 4: The effect of British-Nordic transmission

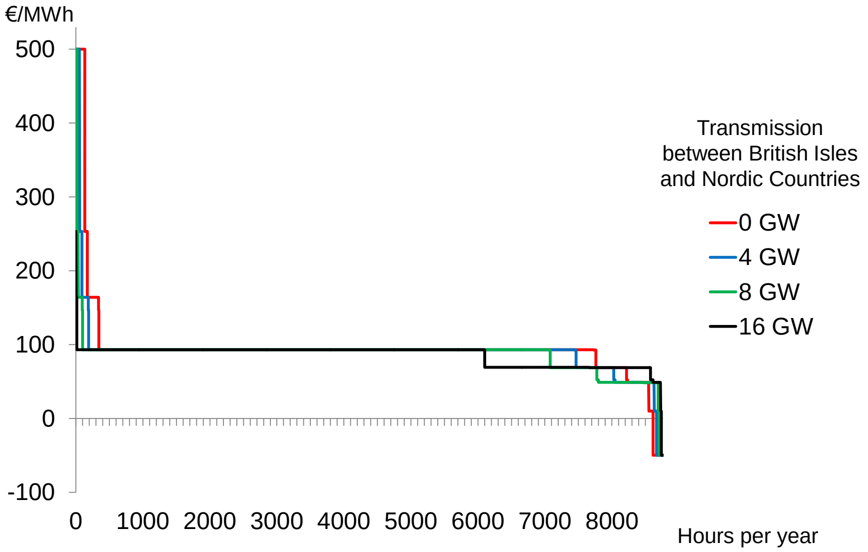


The starting prices are almost identical in Scenario 1 and in Scenario 2, with the price in the British Isles almost double that of the Nordic region. The British price declines gradually as transmission capacity is added, whereas the Nordic price jumps sharply as more of the available water can be exported and its shadow value therefore rises. Once enough capacity has been added to the grid of Scenario 3, the Nordic region has become so well-connected that its average price rises to a higher level than the British Isles had before the transmission capacity was added; the price in the British Isles has also risen.

The sharp rises in Nordic prices, coupled with the ranges of transmission capacity over which they are unchanged, is in part due to the way in which we model hydro. All the hydro capacity in the Nordic region is divided into just two tranches, with shadow water values just above and just below the variable cost of one of the few types of conventional capacity. Those water values are chosen to ensure that the available water is just used up during the year. A more detailed hydro model would reflect the fact that some reservoirs have greater storage capacity than others, relative to their power generation capacity. This means that they would have a range of shadow water values and the changes in Figure 4 might be less abrupt.

The relatively small number of capacity types is also responsible for the long flat segments that can be seen in Figure 5, which gives the price-duration curve for the British Isles. If a region is unable to meet demand in full from its own generation plus imports, the price rises to €500/MWh to compensate some consumers for reducing their loads. If the output of wind and solar plants, plus the must-run element of nuclear power, exceeds the local demand plus exports, then a system operator will have to spill some renewable energy. Under the current market rules of most EU countries, those generators would require compensation equal to the subsidy that they have to forego by not generating, which we set at €50/MWh.

Figure 5: Price-duration curves for the British Isles (S2)



When there is no direct transmission capacity between the British Isles and the Nordic region, there are 132 hours when the price reaches its maximum, and 145 in which it is necessary to spill some renewable power. As the transmission capacity increases, both of these numbers fall. With 16 GW of transmission, it is never necessary to reduce load, and there are only 22 hours with excess generation that cannot be exported. Figure 5 is not a precise prediction of the pattern of prices in 2050, of course, but gives some indication of what might happen, and allows us to draw some policy implications, in the next section.

Conclusions and Policy Implications

In common with most other studies, we find that a low-carbon electricity system in Europe in 2050 will be able to make efficient use of much more transmission capacity than currently exists – the total level of interconnection could rise three- or even six-fold before the additional cost of transmission outweighs the value of generation cost savings. The cost of transmission is relatively small compared to that of generation, and so raising the money needed from regulated charges need not be a significant problem. Recouping this cost from the profit on merchant lines, however, could be a challenge when a small increase in transmission capacity proves able to change the equilibrium prices in the markets at each end by significant amounts, bringing them much closer together. This would be a particular concern for early entrants, knowing that additional capacity could greatly reduce their revenues. Australia experienced this problem when two interconnectors were built at almost the same time; Murraylink, originally planned as a merchant line, had to be transformed into a regulated scheme (Littlechild, 2012). At the very least, this risk would raise the cost of capital for a merchant interconnector, reducing the potential advantage of a "competitive" over a "regulated" solution.

One frequently-heard worry about the electricity markets of the future is that they will be characterised by extreme prices, with either shortages or surpluses of power. We find that if there is sufficient transmission capacity, the number of hours with very high or very low prices will be small. Indeed, there is a risk that the number of high-priced hours would be insufficient to remunerate peaking capacity through an energy-only market. The relatively flat price curves seen in Nord Pool have been sufficient to remunerate hydro stations or those able to run on base load, but offer little prospect for peaking stations to recover their fixed costs. The Swedish transmission company has had to pay separately for reserve capacity, and a number of European countries are introducing, or considering, capacity markets or payments. The results here suggest that these measures are a wise precaution.

One alternative to providing extra peaking capacity is to encourage demand response, giving consumers incentives to reduce demand at times when this would help the power system. It should be noted that ETRC allows the user to specify when electric vehicles are charged, and our scenarios are based on one-third of vehicles following a "smart charging" algorithm which shifts their demand to the lowest-(net) demand periods overnight. The remaining vehicles are split evenly between those charged during the day at the owners' workplaces, and those charged each evening on returning home. This may be a pessimistic split, and the appropriate incentives could see a greater proportion of the fleet charging at the best times for the grid. Even with only one-third of vehicles following smart charging, however, the difference between peak and off-peak prices is often relatively small, and may not provide enough of an incentive to adopt smart charging patterns, particularly if the driver is uncertain when their vehicle will next be needed. Other forms of demand response may also suffer from the lack of a sufficiently strong incentive.

Energy storage is the third way of accommodating inflexible nuclear and intermittent renewables in a low-carbon energy system. Even more than demand response, it depends on price differentials to become economic – the gap between peak and off-peak prices must be high enough to ensure that the storage owner not only makes up for the energy inevitably lost when charging and discharging the device, but also covers its capital cost. Given that those costs are highly uncertain at present, it is too early to say whether the price patterns we predict in this paper will be compatible with the success of storage technologies, particularly as they can also provide reserve and ease network constraints, earning other revenue streams as they do so.

ETRC is a deliberately simplified model of the electricity system; this is a trade-off against its ability to consider the whole range of energy service demands and to capture the great variation in renewable outputs across Europe. It may be that other modellers could take the demand and renewable profiles generated in this model and would find that adding transmission capacity alone would be insufficient to manage a low-carbon electricity system, given the many challenges involved in balancing the grid. As ETRC is an open-source model, we hope that its outputs will be of use to, and used in, many other studies which focus in more detail on parts of the European energy system.

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