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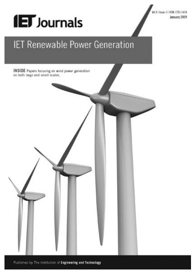

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Transmission network loading in Europe with high shares of renewables

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Abstract: The need for long-distance power transfers in the electricity system is being driven by both deeper market integration and the increasing share of renewables in generation. The best renewables resources are often located far from load centres, while variable renewables, such as wind and solar, benefit from smoothing effects when aggregated over large areas. However, the increased usage of transmission infrastructure raises the question of how the associated costs should be distributed. The authors present here the application of an existing algorithm called marginal participation (MP) which can be used to allocate the power flowing through each network asset (lines and transformers) to particular network users. They consider two new methods to extend the MP algorithm to high voltage direct current lines that operate parallel to alternating current networks. They then apply the allocation algorithm to a future scenario with high renewables penetration in Europe in 2050, developed as part of the Smooth PV project. They see a significant increase in network usage, including a rise in the proportion of cross-border flows. The increase in network usage is driven disproportionately by offshore wind, because of its geographical concentration away from load centres.

1 Introduction

The European power system is undergoing a significant transformation. On the one hand market liberalisation is encouraging cross-border electricity transfers as international competition increases; on the other hand the rise of weather-dependent renewable energy is providing frequent situations of excess local generation and opportunities for export.

The old system, in which power was mostly generated and distributed on a national basis, is therefore being superceded by a more international system, but the mechanisms to allocate the new costs arising from long-distance and trans-national power transfers are not yet in place. In Europe for example, there are regulations to compensate transmission system operators (TSOs) for infrastructure costs and losses incurred by cross-border flows [1], but the algorithms used to allocate costs to particular countries are based only on net transit flows (hence do not see local grid power flows at all) and the total compensation fund (currently €100 million) underrepresents the relevant costs [2]. The regulatory body ACER is currently in consultation to replace the compensation system after 2014.

There is no canonical way to allocate the flow of electricity to particular generators and loads. Of the many methods that have been used in the past, some of which are reviewed here, we settle on the marginal participation (MP) algorithm. MP suits our needs because it is based on a full load flow calculation, it can allocate flows very precisely to particular nodes and it can also take account of beneficial power transfers that reduce loading in the network.

In this paper we use the MP algorithm to consider the contribution of particular generation technologies to power flows. In this way we can quantify which renewables, for example photovoltaics (PV), or onshore or offshore wind, put the most strain on network infrastructure. We also consider the question of how high voltage direct current (HVDC) lines can be integrated into the same analysis.

The motivation for this work was to analyse results arising from the Smooth PV project [3], in which scenarios with high penetration of renewables in Europe were modelled up to the year 2050. In this project the electricity market model of the Energy Economics Insititute (EWI) in Cologne was coupled to Energynautics' high voltage European network model. Transmission infrastructure and generation investments were then jointly optimised up to 2050 under the prescription that CO_2 emissions strongly decrease.

There was a dramatic increase in network usage and inter-regional transfers as more renewables were integrated over the years modelled in the optimisation. In this paper we use the MP allocation algorithm to analyse which technologies drove this increase in network usage in this future scenario, how far renewably-generated electricity was typically transported and how much and where the cross-border flows increased.

2 MP algorithms

2.1 Introduction to allocation algorithms

The purpose of allocation algorithms is to determine which generators and loads are contributing to the flow of electricity on network assets such as transmission lines and transformers. In a meshed network such as the high voltage European grid there is no unique way to make this assignment of power flows, but there exist several different algorithms of varying complexity and physicality which can provide an allocation. We review a selection of these algorithms below.

In Fig. 1 a fictitious example of such an allocation is given, inspired by the oft-cited concern that wind power generated in northern Germany and destined for southern Germany often makes its way via loop flows through the networks of Germany's neighbours, overloading network assets there. Each MW of active power flowing through the transmission line is allocation to a particular node within the network (here we have assumed that the flow is divided 50–50% between generators and loads). Although the line is located in Poland, 70% of the flow consists of a power transfer between a German generating node (DE1) and a German load (DE2). In this example we have further subdivided the generation into the particular generation technologies feeding in at the high voltage substations.

2.2 Other allocation algorithms

In this paper we focus on the allocation algorithm called 'MP', but before we explain why we have chosen this algorithm, we review some of the other widely-used algorithms for allocating transmission system usage. Desirable properties for an allocation algorithm include fairness (so that those who benefit most from the network contribute most towards its cost), stability (so that small changes to the nodal power balances cause only small changes to the allocation), adherence to the physical principles of load flow, simplicity and the ability to identify power transfers which reduce loading in the network (it is a pre-requisite of European Commission Regulation 838/2010 [1] that such beneficial contributions are taken into account). Other reviews and comparisons of transmission allocation methods can be found in [2, 4–6].

The most basic allocation methods ignore the flows in the network entirely and assign the transmission costs based only

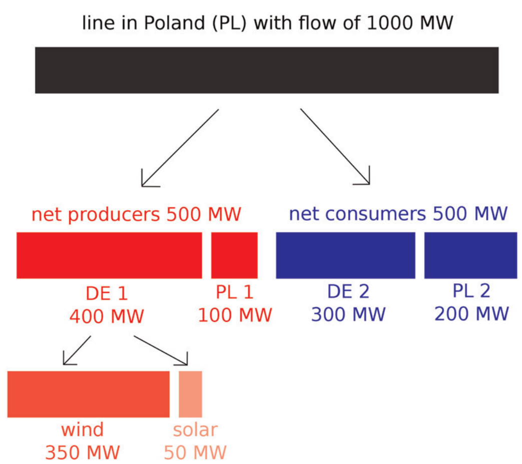

Fig. 1 *Fictitious example of the allocation of an active power flow of 1000 MW in a transmission line in Poland near the border with Germany to network nodes in Germany (DE1 and DE2) and Poland (PL1 and PL2)*

Flow is split 50–50% between generators and loads, which are dominated by German nodes in the network. The allocation can be further split up into the different generation technologies at each node

on the power balances in the network. For example, the 'Postage Stamp' method [5] assigns the transmission usage of each user according to the proportional of the user's power injected/withdrawn compared with the total power injected/withdrawn in the system. These methods do not meet our needs because they do not attempt to assign the flows caused on individual lines to individual nodes.

Some methods, such as 'average participation' take the power flows resulting from a load flow calculation and then decompose the flows based on a tracing methodology [7, 8]. In average participation one follows paths in the acyclic directed graph of flows from sources (nodes with only outgoing flows) to sinks (nodes with only incoming flows), assuming that the incoming flows at each node divide equally among the outgoing flows at the node. The different paths between sources and sinks passing through each branch provide the subdivision of its power flow between the different users. This methodology assumes that power flows such as water splitting at a junction rather than as electrons flowing according to impedances, and therefore lacks a physical correspondence to the load flow. As a consequence, it lacks the ability to detect beneficial power transfers that reduce loading in the network, since it does not allow the superposition of opposing flows.

Another method which does take account of beneficial flows is called 'with and without transits' (WWT). WWT is currently used in Europe to assign the costs of transmission losses because of cross-border flows [1]. The method works by comparing the flows through a country's network with the flows if all power transits between third parties across the country are removed. In practice this means that the cross-border lines at the country's boundary are replaced by dummy generators, whose power is then adjusted so that they only provide the net export or net import necessary to meet the country's overall power balance. The difference between the power flow on a line before and after is then allocated to the transit flows. This method has the disadvantage that it can only distinguish between domestic and foreign usages of a country's network, therefore it is not suitable for assigning individual flows to individual nodes.

The 'Aumann–Shapley' method [9] uses game theory techniques for the allocation that allow agents to optimise their network usage in turn as they join the network. It allocates the costs of branches to the agents based on the results of the optimisation. Although this method is economically efficient and physical (it uses the linearised load flow equations), the optimisation at each step is too computationally intensive for our purposes here.

2.3 Marginal participation

MP [10] is an allocation algorithm which works by linearising the network equations for power flow in an AC network and using this linearisation to measure the sensitivity of each branch's active power flow to changes in the power balances of the nodes. The marginal sensitivities to each node can then be multiplied by the nodal power imbalances and linearly superimposed to reproduce the full bulk flow (this is equivalent to a 'DC' load flow for an AC network).

This algorithm has all the properties we require: it provides an allocation of the flow on each branch to each node in proportion to the node's usage of the branch, it is stable, it is based on a load flow calculation, it is relatively simple and it can take account of beneficial power transfers within the network (since individual nodes can contribute both

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positively and negatively to the magnitude of a branch's power flow).

To describe the algorithm in more detail, it is useful to introduce the Power Transfer Distribution Factor (PTDF) matrix to describe the linearisation, so that the active power flows p_a on the branches $a \in A = \{1, \ldots |A|\}$ are related to the nodal power balances p_i for $i \in I = \{1, \ldots |I|\}$ by multiplication with PTDF matrix elements PTDF_{ai}

$$p_a = \sum_{i \in I} \mathrm{PTDF}_{ai} \, p_i \tag{1}$$

The nodal power balance p_i at node i is defined by subtracting the load ℓ_i from the total generation dispatch d_i at the node, $p_i = d_i - \ell_i$. For simplicity we assume for this discussion that all nodes are connected in a single synchronous zone.

The matrix elements $-1 \leq \mathrm{PTDF}_{ai} \leq 1$ can be calculated either 'experimentally' or directly from the impedances in the network [11]. The 'experimental' method involves measuring the power flow in a basis situation, picking a slack bus, then going through each node in the network and injecting 1 MW at the slack bus and withdrawing 1 MW at each node in turn. The change in power flow on each branch a for each choice of node i gives the sensitivity PTDF_{ai}.

Already the PTDF sensitivity elements do the job we require, by telling us that the power imbalance p_i at node i contributes $\mathrm{PTDF}_{ai}\, p_i$ to the flow p_a along line a. However, the result is highly dependent on the choice of slack bus. This has not stopped this method from being used in some countries, where the slack node has been chosen as a large load centre [12].

There are several ways to remove this dependency on the slack bus. One option is to distribute the slack across all the generators in the network, according to how much active power they dispatch [13]. Another approach, which we will consider here, involves assuming that the flow on each line can be divided between the net producers and the net consumers in the network according to some fixed ratio, for example 50–50%. We now explain how this is done.

The freedom to choose the slack node is reflected in the non-unique definition of the PTDF_{ai}. Because there are no losses in the network, the power balances of the nodes must sum to zero $\sum_{i \in I} p_i = 0$. Using this, we can add to each row of the matrix PTDF_{ai} a constant k_a

$$\mathrm{PTDF}_{ai} \rightarrow \mathrm{PTDF}_{ai} + k_a \tag{2}$$

without altering the calculated power flow p_a on branch a. This can be checked by feeding (2) back into (1).

The k_a can now be chosen for each line according to how we want to allocate the flows.

2.4 Different MP algorithms

2.4.1 Standard MP: 50–50% split between net consumers and producers: For the standard MP implementation we choose k_a so that if we sort the nodes into net consumers $C \subset I$ (with net power balance p_i negative) and net producers $R \subset I$ (with net power balance p_i positive) the flow on each line p_a is allocated in half between them

$$\frac{p_a}{2} = \sum_{i \in C} (\mathrm{PTDF}_{ai} + k_a) p_i = \sum_{i \in R} (\mathrm{PTDF}_{ai} + k_a) p_i \tag{3}$$

From this equation we can calculate k_a for each line

$$\begin{aligned} k_a &= \frac{(p_a/2) - \sum_{i \in C} \mathrm{PTDF}_{ai} \, p_i}{\sum_{i \in C} p_i} \\ &= \frac{(p_a/2) - \sum_{i \in R} \mathrm{PTDF}_{ai} \, p_i}{\sum_{i \in R} p_i} \end{aligned} \tag{4}$$

For each node the flow on line a because of node i is simply $(\mathrm{PTDF}_{ai} + k_a)p_i$. The choice of k_a ensures that when we sum the contribution from net consumers, we will obtain $p_a/2$ and exactly the same when we sum the contribution from net producers.

Note that the allocation and the constants k_a depends on the distribution of power over the nodes for a particular snapshot, and is only valid for this single load flow.

When MP is used for inter-TSO compensation, cross-border flows are those which are caused on a network branch by a node in a different country. Using MP with the 50–50% split, cross-border flows in Europe currently amount to around 20% of all flows; the remaining 80% are domestic in origin (extrapolating from [2]).

2.4.2 Allocation only to net generation: If one is only interested in the effect of the generation mix on the network loading, the full flow can be assigned to the net producers (i.e. a 0–100% split between net consumers and net generators). The k_a are then chosen so that

$$p_a = \sum_{i \in R} (\mathrm{PTDF}_{ai} + k_a) p_i \tag{5}$$

which results in the following formula for the k_a

$$k_a = \frac{p_a - \sum_{i \in R} \mathrm{PTDF}_{ai} \, p_i}{\sum_{i \in R} p_i} \tag{6}$$

To obtain the effect of each generation technology (e.g. wind/PV/gas/coal) at each aggregated node, we can further refine the allocation by subdividing the contribution of each net generating node in proportion to the current dispatch of technologies (cf. Fig. 1). If the generation dispatch d_i at node i is the sum of the dispatch $d_{i,\,g}$ for each generation technology g, $d_i = \sum_{g \in G} d_{i,g}$, then the allocation for line a for each technology g at node i would be proportional to that technology's share of the absolute generation dispatch [Storage has been excluded from this analysis, because its negative dispatch can create singularities in the denominator of (7).]

$$\frac{d_{i,g}}{\sum_g d_{i,g}} (\mathrm{PTDF}_{ai} + k_a) p_i \tag{7}$$

Since we are interested in this paper in network loading resulting from changes to the generation fleet because of the integration of renewables, we will focus on this second algorithm using net generation in what follows.

2.5 Incorporating HVDC lines

In this section we consider how to incorporate HVDC lines into the MP allocation algorithm.

Until now most HVDC lines have been built to connect non-synchronous AC zones and connect power systems across large bodies of water. Increasingly they are also being considered within synchronous zones. The advantages they offer include: lower losses for long-distance power transport; no need for reactive power compensation along the lines; and, because they provide point-to-point controllable power transfers, loop flows through indirect routes common in AC networks can be avoided. This last point is relevant for example in Germany, where the power from high wind feed-in in the North is not transported directly to the loads in the South, but spreads out on the way into the neighbouring countries such as Poland, the Czech Republic, the Netherlands and Belgium. In Germany's Network Development Plan [14] three north-south HVDC corridors are currently under consideration. Further into the future, it may be possible to build a meshed DC 'overlay' network that supplements the AC network by providing continent-wide power transport, cf. Fig. 2.

It is not straightforward to incorporate HVDC lines into the MP flow allocation algorithm, because the PTDFs are derived for AC networks only. PTDFs essentially encode how the power passively flows through the impedances, once the nodal power imbalances have been set. While MP can also be applied to a purely DC network (by linearising the DC load flow equations which encode the passive power flow because of the resistances in the DC network), it does not translate naturally to mixed AC–DC systems, since the power flow between the AC and DC networks is controllable and therefore does not change in response to marginal changes in load or generation. The issue is not just that the HVDC lines alter the flow in the AC network, as identified in [15], but that we also want to be able to allocate the flows in the HVDC lines themselves to particular market actors. Since the main loads and generators are still connected to the AC network, it is not always clear which actors are making use of the DC network.

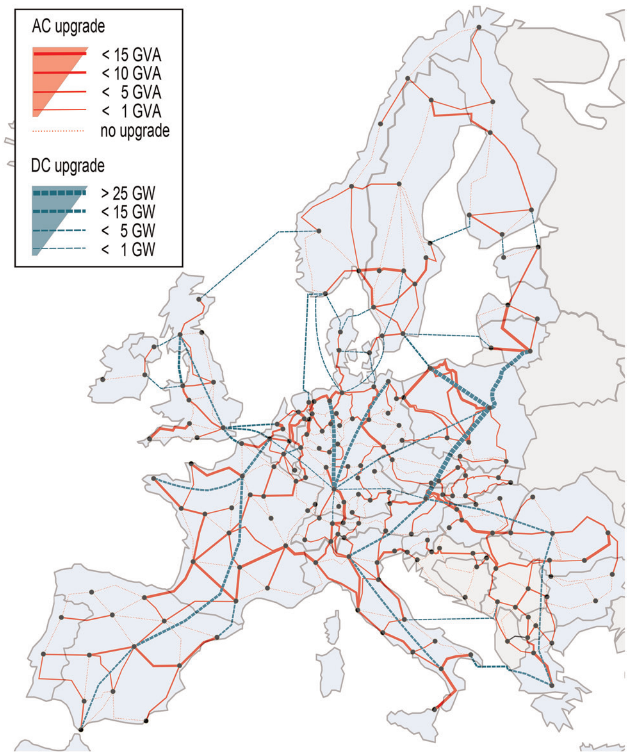

Fig. 2 *Network expansion projects in the optimal scenario built out between 2020 and 2050*

Red solid lines are AC upgrades and green dashed lines are DC extensions

One method in the literature to incorporate HVDC lines in the MP method involves measuring the changes to the MP allocation in the AC network as HVDC lines are sequentially disconnected from it [16]. By comparing the total MP cost allocated to each node in the AC network before and after the disconnection of the HVDC line, the costs of the HVDC line can be allocated proportionally to the benefit each node receives from the line. One problem with this method is that by forcing the HVDC power flows into the (now overloaded) AC network for the allocation, it becomes distorted by the parallel loop flows in the AC network which HVDC lines are designed to avoid. While this may be acceptable for small HVDC systems, it becomes particularly problematic for larger systems such as the overlay HVDC network considered in the next section.

We have two new suggestions for how to allocate the usage of the HVDC network to particular assets in the AC network

1. The first method is to let the DC network inherit its allocation proportionally from the allocation of the AC lines connected to it. If the DC node is drawing power from the AC network, then the node acts like a generator in the DC network and inherits the allocation to AC generators from the AC lines supplying it. If the DC node is feeding power into the AC network, then the node acts like a load in the DC network and inherits the allocation to AC loads from the AC lines it supplies. This method gives an accurate picture of which AC loads and generators are using the DC network but has the disadvantage of complexity, particularly for meshed DC grids.
2. Alternatively, when the DC line is between two well-defined regions encompassing several nodes (such as countries or federal states), one can simply divide the allocation of the DC flow 50–50% between the two regions. Within the region from which the flow originates, the allocation is divided among all net generating nodes according to their power; within the region to which the power goes, it is divided among all net consumers in the region. This has the disadvantages that it cannot see the usage of the HVDC line by third parties outside the two regions and that it does not necessarily provide an accurate allocation within the region. On the other hand, it is simple and by reducing the allocation to the two regions where the HVDC line ends, this would probably reflect how investments in building the line are made and how the power flows are contracted between the two regions.

In this paper we have avoided method (1) because of its computational complexity, although it represents the most accurate allocation. The allocation for international HVDC lines between countries is done following suggestion (2), according to the two regions which the lines connect, because of its simplicity and the similarity of its allocation to how the flow on the line would most likely be contracted by the two regions it connects.

3 Scenario for high shares of renewables in Europe

3.1 *Results from the Smooth PV project*

In the Smooth PV project [3] long-term investments in generation and transmission in Europe were jointly optimised for social welfare over the next forty years under the condition that CO_2 emissions are drastically reduced. We present here a brief summary of the results of the

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Table 1 Selection of investment costs used in the optimisation

Asset	Unit	2011	2020	2030	2050
AC overhead line	€/MVAkm		445		
DC overhead line	€/MWkm		400		
DC submarine	€/MWkm		1100		
DC converter pair	€/MW		150000		
combined cycle gas turbine	€/kW		1250		
open cycle gas turbine	€/kW		700		
compressed air storage	€/kW		850		
PV ground	€/kW	1532	1167	842	661
PV roof	€/kW	1702	1297	935	734
wind onshore	€/kW	1250	1200	1150	1050
wind offshore	€/kW	3100	2200	1900	1700

simulations; for more details and the full assumptions behind the optimisation see [17]. Then we analyse the increase in transmission system usage seen in the scenario.

To simulate the power flows in the European transmission network, Energynautics' detailed model of the high voltage grid was used. This model was developed with DIgSILENT's power system calculation tool PowerFactory and covers all ENTSO-E members. It consists of over 200 nodes, representing generation and load centres within Europe, 450 high voltage AC (HVAC) lines, and all the high voltage DC (HVDC) lines within the ENTSO-E area. The model covers the four main points in time simulated in the optimisation: 2011, based on the current network; 2020, including all mid-term planning projects from ENTSO-E's Ten Year Network Development Plan [18]; for 2030 and 2050 the network extensions were calculated during the optimisation. For the 2030 and 2050 networks the optimisation was also given the option to build out an HVDC overlay grid which connected the major load and renewable generation centres in each market region (see Fig. 2). To incorporate the network model in a linear optimisation calculation, the load flow equations for the AC network were linearised in the standard way known as a 'DC' load flow; international HVDC lines were independently dispatched by the optimiser.

To compute the investment optimisation, the network model was coupled to the linear electricity market model developed at the Energy Economics Institute (EWI) in Cologne [19]. Generation and network infrastructure expansion were jointly optimised for social welfare based on a 90% CO_2 reduction in the electricity sector by the year 2050 compared with 1990 (which corresponds to an indicative target given by the EU council [20]). The objective of the optimisation is to reduce total system costs. These costs are accumulated over the simulation years and discounted (at a rate of 5%) and include investment costs, fixed operation and maintenance costs, variable production costs and costs because of ramping thermal power plants. The investment horizon was extended to 2070 to avoid investment distortions in the final simulation year 2050.

The most important investment cost assumptions are listed in Table 1. Although the cost of conventional plant such as gas remains constant over the simulation years, considerable cost reductions are assumed for offshore wind and PV in particular. A full list of fixed and variable costs can be found in [17]. The costs are based on an extensive literature review carried out in the framework of the Smooth PV project [3]. All assets have a fixed lifetime, after which they are retired (ranging from 25 years for solar panels and wind turbines to 100 years for hydroelectric plants); the ages of existing plant are based on the Platts WEPP Database [21] and EWI's own research.

Demand levels are taken from ENTSO-E for 2011 and extrapolated according to region-specific GDP growth. The total demand in the ENTSO-E area rises from 3525 TWh/a in 2011 to 4833 TWh/a in 2050; see [17] for a country-by-country breakdown of the demand growth.

The dispatch of generation was calculated for the years 2011, 2020, 2030 and 2050 using eight typical days per year on an hourly basis, representing variations in electricity demand as well as in weather-dependent solar and wind resources during a full year. Only eight days were simulated in order to keep the computation times manageable. The typical day profiles were constructed such that the statistical features of the original demand, solar and wind data [22] (mean values, seasonalities, gradients and spatial correlations) were maintained for each combination of the following three situations: summer/winter; workday/weekend; high/low infeed from wind and solar. In this way the availability profiles represent the geographical variation of renewable resources across the continent and also cover extreme events that particularly stress the power system,

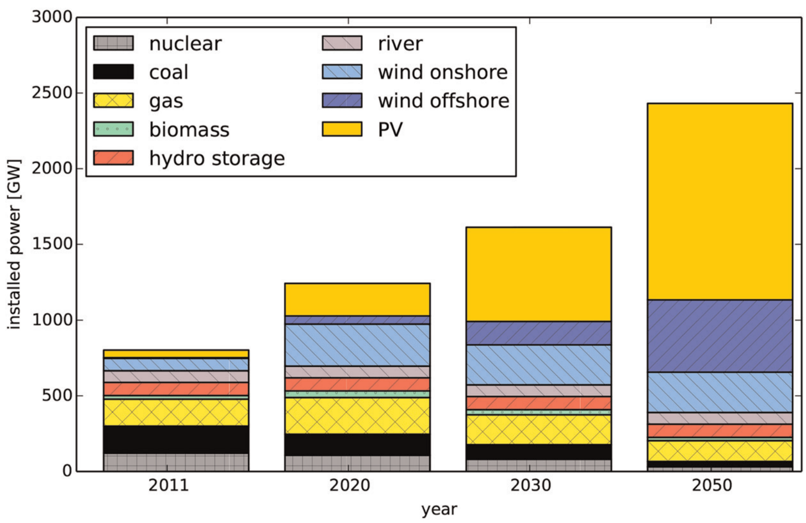

Fig. 3 *Installed capacity in Europe in the simulated years per technology*

such as periods of low wind and high demand. For a detailed description of the methodology that was developed to derive the typical days, the reader is referred to [23].

Curtailment of all variable renewable power sources was allowed. The dispatch of storage and the ramping of conventional power plants is chronological between the hours of each simulation year. Minimum part-load levels are respected for all power plants.

The network capacities were optimised jointly with the generation infrastructure. Since the impedances in the network change as it is upgraded, the load flow equations, which depend non-linearly on the impedances, were updated after each optimisation run in an iterative process that converged after a small number of steps. The full methodology is presented in [17, 24].

As a result of the cost-optimal optimisation, both capacities of renewables and of the transmission system were expanded. In 2020, before the network expansion but taking into account mid-term TYNDP projects, there was a total of 1040 GVA AC line capacity and 25 GW DC line capacity. By 2050 the optimised expansion added 953.5 GVA AC and 211.3 GW DC, more than doubling the total network capacity. See Fig. 2 for the geographical distribution of new lines.

The installed capacities and generated energies per technology for the entire ENTSO-E area are displayed in Figs. 3 and 4. Onshore wind reaches the model's potentials by 2030 already with 264 GW, which increases only to 266 GW in 2050. Since all potential sites are exhausted, onshore wind is relatively evenly distributed across the continent. On the other hand offshore wind becomes cheaper over time and has larger potentials, leading to capacity of 155 GW in 2030 and 478 GW in 2050. Unlike onshore wind, offshore capacity is geographically concentrated, particularly in northern Europe, with for example 38 GW off Germany's North Sea coast, 20 GW on the Baltic side and an enormous 51 GW in Poland.

For PV significant price reductions (see Table 1) drive PV capacity to 621 GW in 2030 and 1297 GW in 2050. By 2050 capacities are relatively evenly spread across Europe. At the best sites in southern Europe potentials are exhausted in 2050 and there is even 9 GW installed in Norway, where resources are poor. Storage excluding pumped hydro, which is not displayed in the graphics, rises to 115 GW in 2030 and 414 GW in 2050.

Next we turn to the generated energy in Fig. 4. Although wind power represents 26% of installed capacity, its production share amounts to 40%. In contrast, solar power takes a 45% share in total capacity but only 32% in total production, thanks to its lower full load hours. Curtailment, which is allowed in the model, was 0.4, 2.7 and 6.4% for PV, onshore and offshore wind.

The accumulated discounted total system costs until 2050 amounted to €2833 billion. Of this total, €671 billion corresponded to variable production costs, €771 billion to fixed operation and maintenance costs, €1386 billion to investment costs and €5 billion to the costs because of ramping thermal power plants. Of the investment costs, €1342 billion came from generating plant, while the rest (3.2%) came from upgrades to the transmission system. 23% of the transmission system costs went towards HVDC infrastructure and 77% to HVAC.

3.2 Transmission network loading in the future scenario

Regarding the transmission network loading, a useful measure is to add up for each line the power flowing through it at a given time multiplied by the line's length (measured in units of MWkm). This gives an indication of how much power is being transported over long distances in the model. As can been seen from Fig. 5 there is a substantial increase in long-distance power transmission between 2011 and 2050, particularly for DC lines.

It is important to note that this increase in transported power arises not because individual lines are being loaded higher as a fraction of their thermal limits (this loading factor remains reasonably constant for AC lines at an average of around 25%), but because more capacity is needed and built out.

To understand what is driving the expansion of the network and the corresponding increase in network loading, we turn now to the Mariginal Participation allocation algorithms.

3.3 Technology-specific allocation with MP

In this section we apply the MP algorithm developed in Section 2 to the results of the Smooth PV project presented above. We want to quantify how much of the network

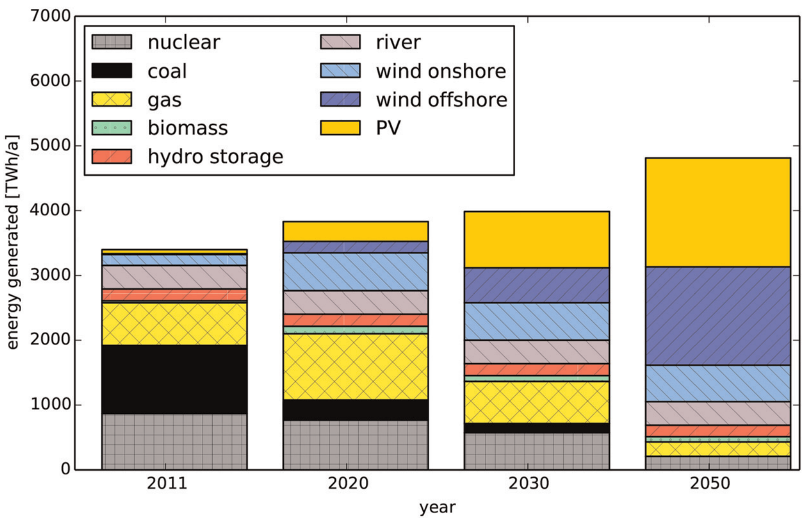

Fig. 4 *Energy generated in Europe in the simulated years per technology*

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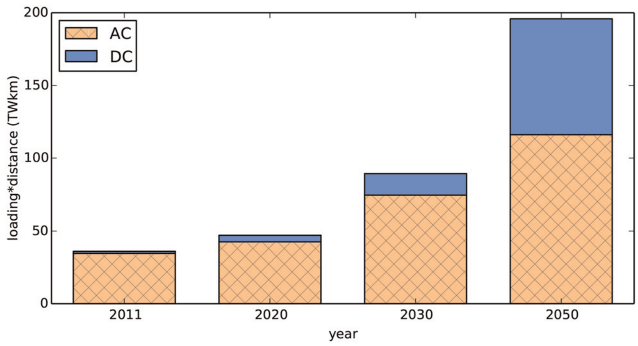

Fig. 5 *Network loading in Europe over the simulated years, measured as a sum of the loading in MW of each line multiplied with its length, averaged over the snapshots*

loading is being caused by which nodes and in particular by which generation technologies. We focus on generation rather than the load, because it is the generation fleet which changes when we force a reduction in CO_2 emissions.

Using the MP allocation method for net generation from Section 2.4.2, we obtain an allocation of the flow along each line in the model to each node where there is net generation, and furthermore to each generation technology at that net generation node.

If we now sum up the contributions from the particular technologies over all the lines, we can see what is driving the network loading. In Fig. 6 both the generation dispatch and the network loading from different technologies is plotted over the eight simulated typical days. Both conventional sources and hydro have an underrepresented contribution to the network loading, since they often act to help reduce network imbalances. PV has a similarly modest contribution to the network loading, since PV is relatively evenly distributed across the network (by 2050 it is assumed to be so cheap that large amounts are installed even in northerly countries). Wind, and in particular offshore wind, has a massive over-representation in the network loading. In the windy hours offshore wind dominates, contributing in one dispatch snapshot to 59% of total generation but 78% of the network loading. This is not surprising, since offshore wind is generated along the coastlines of Europe, which does not necessarily correspond to where the load centres are.

A different way to look at this information is to divide the network loading in MWkm by the dispatch in MW to obtain what is effectively the distance travelled by each MW generated by each technology source. This is plotted in Fig. 7 for each of the simulated years. All generation technologies show a tendency to be transported further over time, as the mismatch between the geographical distribution of generation and load in the model increases. Offshore wind shows a particularly strong increase, travelling twice the distance of PV by 2050.

Since MP allocates the line flows on a per-node basis, we can refine our analysis geographically and see in which areas the generation supply is causing high loading. For example, for the snapshot at the end of the seventh day, where offshore wind makes up 78% of the total network loading, the loading is mostly driven by the northern European countries where the majority of offshore wind is installed. Network stress in Poland is particularly acute, accounting for 40% of the total loading because of offshore wind and contributing nearly three times as much as the next highest countries Germany and the Netherlands. The reason is that Poland's offshore installed capacity of 51 GW, resulting in a dispatch of 35 GW, is concentrated on the only coastal Polish node in the aggregated network model. This also explains why so much of the AC and DC network is expanded around this node (see the network diagram in Fig. 2); it is nearly all to accommodate offshore wind here. For PV and onshore wind the generation is more evenly spread around the network hence causes fewer local stresses.

This shows the advantage of using flow allocation algorithms, such as MP: particular network expansions

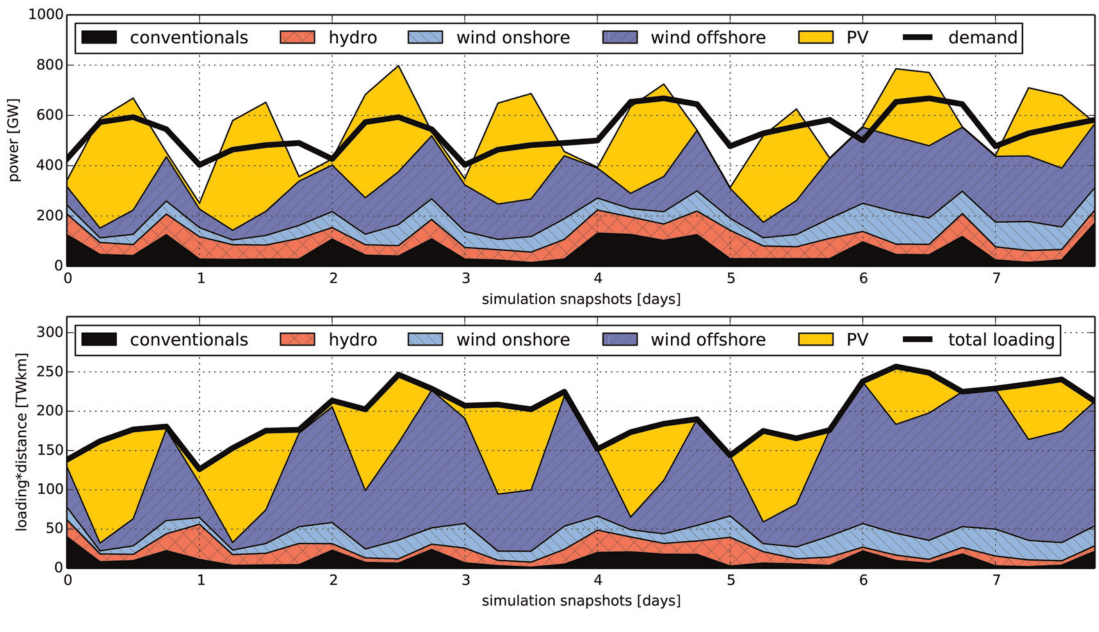

Fig. 6 *In the top graph is the dispatch of generation over the eight simulated days in Europe, with four simulated hours per day*

Difference between the total generation and the total demand is covered by storage technologies, which shift the energy in time. In the bottom graph we have the division of total network loading into the different technologies causing the loading, allocated according to the MP algorithm. It can be seen clearly that offshore wind has a disproportionately large contribution to loading compared with its generation power

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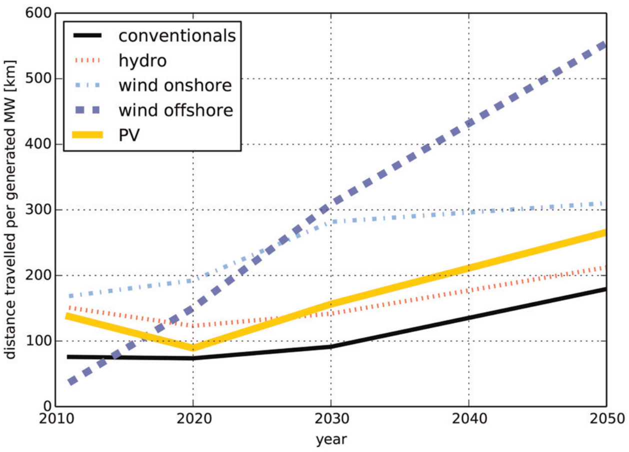

Fig. 7 *Average distance travelled by each MW from each generation source as it develops over the simulated years*

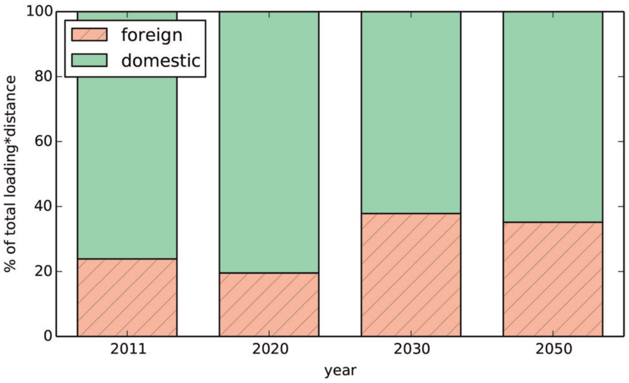

Fig. 8 *Proportion of network loading of assets arising from within the same country and from foreign sources across the whole European network*

By this measure, the share of foreign flows more than doubles between 2020 and 2050

determined by the investment optimisation can be traced back to the contribution of particular nodes and indeed particular generation technologies there.

3.4 Cross-border flows with MP

We now analyse the cross-border flows in the model using the standard MP method outlined in Section 2.4.1, which splits the flow on each line 50–50% between net power consumers and producers. We use the 50–50% method because we are now equally interested in where the generated power is consumed, since this will determine whether the resulting power flows are international or not.

A power flow is counted as 'domestic' if the node causing it is in the same country as the line; otherwise it is 'foreign'. Foreign flows are not just transfers between two countries, but also transit flows that pass through third countries on their way to their destination.

In Fig. 8 the proportion of foreign to domestic flows in the entire European network are plotted for the four simulated years. Between 2011 and 2050 the share of foreign flows rises from 24% in 2011 and 35% in 2050, but this rise is not monotonic. The share of foreign flows drops from 24% in 2011 to 20% in 2020, which is caused by a big rise in generation by flexible gas power plants, replacing the old coal and nuclear fleet (see Fig. 4).

The second exception is the small drop in cross-border flows from 38% in 2030 to 35% in 2050. This drop is a result of the big expansion of the HVDC network in 2050 (see Fig. 5). Because HVDC lines provide point-to-point power transfers, they remove parallel loop flows from the AC network. Loop flows are a big source of transit flows, whereby power flows through third countries on its way from generator to consumer.

We can quantify the effect of the HVDC network by changing the way we allocate the flows in the HVDC lines to nodes in the network. Following the discussion in Section 2.5, we chose to use method (2) to allocate flows on international HVDC lines, whereby the flows were allocated to the two countries connected by the lines. If however we simply remove the HVDC lines within synchronous zones from the model and force the flows into the (now overloaded) AC network, we see instead a rise of foreign flows from 38% in 2030 to 42% to 2050. This shows us that without the HVDC lines, we would be seeing significantly more transit flows.

It is a common complaint of countries towards the centre of the meshed European network that they are particularly badly hit by transit flows in their networks. In Fig. 9 the domestic-foreign split per country in 2050 is plotted. Central countries, such as Switzerland (CH), Slovenia (SI) and Slovakia (SK) are particularly badly hit, with some foreign fractions close to 100%. The reason it is so high in some countries is because MP is also sensitive to power transfers that 'reduce' network loading. For example, in some dispatch snapshots for Slovenia the foreign-domestic split is 110% to −10% because the domestic flows are in the opposite direction to the international flows and hence have a beneficial effect (cf. Fig. 10 and the discussion in [2]). Portugal, although it is at the edge of the European grid, also has a relatively high share of cross-border flows

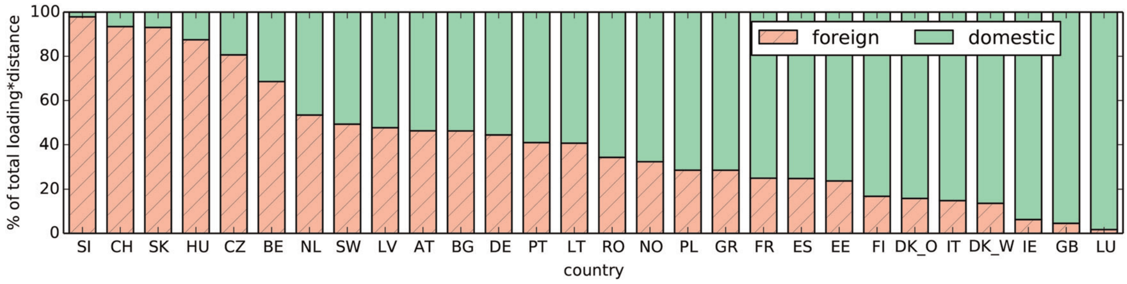

Fig. 9 *Proportion of foreign and domestic flows in each country averaged over the year 2050*

Standard ENTSO-E abbreviations for the countries are used. Note that although all countries are presented equally here, the total loading would vary considerably between countries

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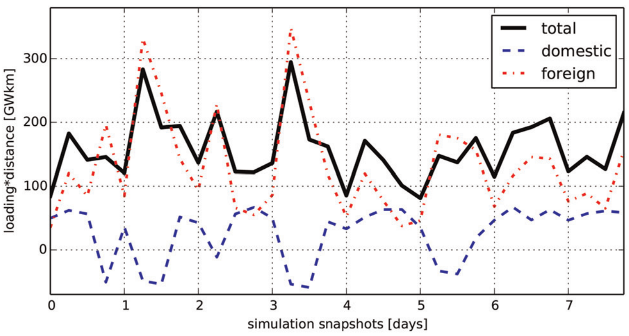

Fig. 10 *Network loading in Slovenia in 2020 over the simulated days*

Contribution from foreign cross-border flows is high. However domestic transfers can flow in the opposite direction and help reduce total loading

because of exchanges of power, mostly large imports, with Spain.

4 Conclusions

In this paper we have applied a technique called MP, commonly used in inter-TSO compensation mechanisms, to study power flows arising in a scenario with high levels of renewables developed in the Smooth PV project [3]. We have used the technique to look at the influence of particular generation technologies on the network loading and we have developed ways of incorporating HVDC lines in the flow allocation, including those that sit within synchronous zones.

The allocation techniques allowed us to identify which generation technologies installed in which places drove the large network expansion calculated in the scenario up to 2050. Offshore wind played the biggest role, as infrastructure was built to transfer power from Europe's coastlines where offshore wind resources are concentrated. PV and onshore wind were less significant drivers of network expansion, since they were more evenly distributed across the continent.

There was a marked rise in cross-border power flows within Europe as renewable generation increased over the simulated years. This was partly alleviated by the overlay HVDC network, which reduced parallel loop flows in the AC network.

As renewables' share of Europe's electricity generation rises over the coming decades, this study indicates that it will drive both network expansion and higher cross-border flows. The need to allocate the associated transmission costs fairly will necessitate more sophisticated compensation mechanisms than those currently in use in Europe [1]. Of the many allocation algorithms available, MP has several attractive features, including simplicity, a clear allocation of flows to users, physicality and the ability to take account of beneficial power transfers within the network.

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