New Task Allocation in a Context of Growing Amounts of Intermittent Renewables – Suppliers as 'Residual Portfolio'-Managers

By Eva Hauser, Uwe Leprich, Martin Luxenburger

Renewable electricity production in Germany in 2011 closely approached the 20%-mark with nearly 122 TWh produced while Germany's gross electricity generation reached about 612 TWh. Germany thus doubled its renewable production since 2004. While the amount of hydroelectricity and electricity stemming from the use of organic household waste remains stable with about 25 TWh since 2004, it is mainly the 'new' renewables like wind, photovoltaic and biomass that contribute to the growing share of electricity production. Their development has largely and successfully been incentivized by the German Renewables Act (the "EEG").

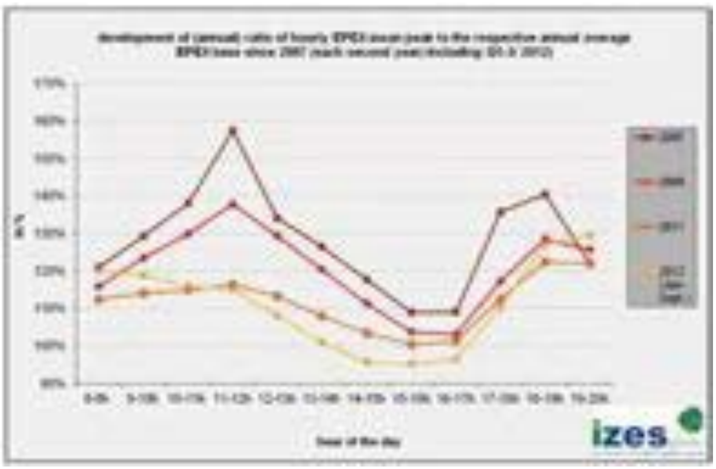
Like all other EU member states, Germany aims at constituting a new energetic infrastructure in order to decarbonise the energy system and to minimize the dependency on non-renewable fossils or nuclear energy sources and to reduce the external effects of these conventional energies. Consequently, the German legislator set a precise goal concerning renewable energy supply for the decades to come. With the new EEG 2012, this goal is set by at least 35% of the total electricity supply in 2020 and is set to increase consequently up until at least 80% in 2050.

But this rapid growth leads to many new challenges. Most spectators would guess they are of a technical kind, but there are also many economic and institutional challenges to be faced as well. One of them is the question of how to allocate the renewable electricity in the markets or – finally - among end users. While this question actually may seem to be a specific German one, it may soon concern more EU member states whose share of renewables is growing or who simply take part in the interconnected electricity exchanges.

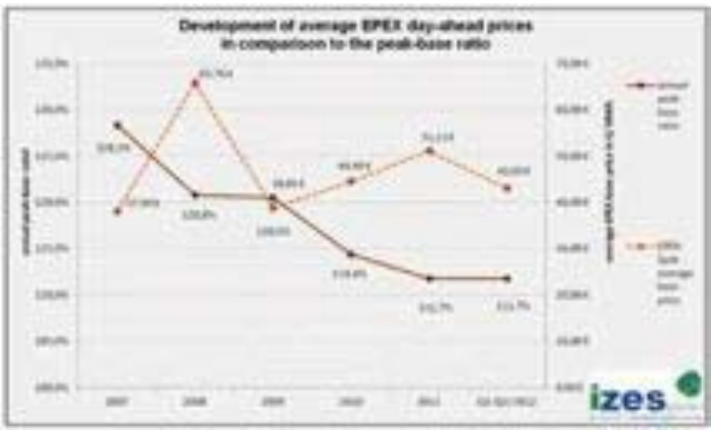
Since the beginning of 2010, the German TSOs are obliged to sell the production of the EEG-producers exclusively on the German-Austrian day-ahead spot-market of the common French-German-Austrian electricity exchange, the EPEX. With about 65.5 GW of installed renewable capacity at the end of 2011 (consisting of 29.1 GW wind generators and 24,8 GW PV), renewable power amounted to a total production of nearly 122 TWh while the German-Austrian EPEX day-ahead volume reached about 225 TWh. Thus, renewables represented more than 50% of the EPEX day ahead volume in 2011. The increasing amount of renewables sold unlimited on the spot-market thus lead to declining spot-market prices via the right-hand-shift of the German merit order. According to the respective peak load which varies between 40 and maximum 80 GW with a mean load of 65 GW, renewable feed-in becomes continuously more price setting. This development – the so-called “merit-order-effect of renewable energies” leads to falling spot market prices in general.

But the different kinds of renewables do not all present the same effects on the electricity (spot) market prices: While some renewables can –at least technically - be regulated by their operators, wind energy is intermittent, but does not follow a specific daytime pattern. Principally photovoltaic presents a specific pattern due to its synchronicity with daylight. Wind, hydro or biomass do generate a kind of ‘overall’ merit-order-effect which contributes to generally lowering the electricity spot market prices.

Photovoltaic energy strongly influences spot market prices during the actual peak price phases in electricity markets (from 8 a.m. to 8 p.m. on the French-Austrian-German EPEX). This is illustrated in graph 1. Consequently, the ratio of the hourly average peak prices to the respective annual base prices decreases continually since 2007. This can be seen in graph 2. While the average base prices vary (but generally tend to slightly fall due to the renewables-induced merit-order-effect), the peak base ratio fell from about 128% in 2007 to an actually rather stable value of 111%. The daily profile of the electricity spot market prices has thus generally been levelised, approaching base values. Furthermore, a new kind of profile seems to emerge: While the



←Graph 1.



←Graph 2.

former daily maximum prices occurred at noon and a second interval with high prices occurred in the early evening hours, the daily maximum intervals now lie during the morning and the evening hours. The mid-day peak has been cut and the (average) afternoon prices even lie beyond the annual average base prices. In sum, there is no longer a continuous peak interval from 8 a.m. to 8 p.m., but some quite short peak phases in the morning and the evening and one may even talk about an "off-peak phase" quite close to the middle of the day, i.e. in the early afternoon.

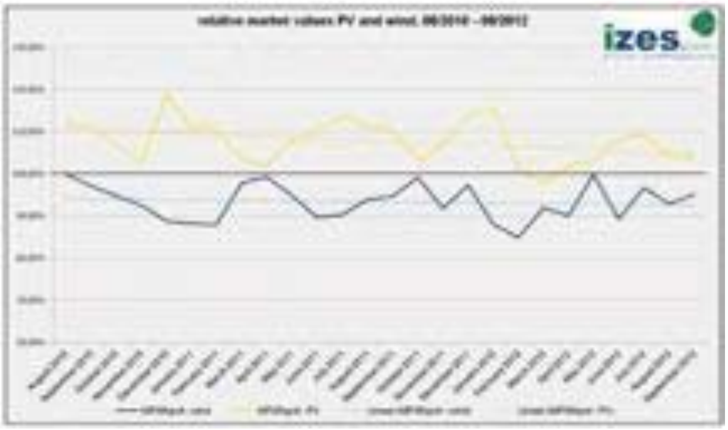
These emerging daily price profiles show up an important characteristic of intermittent electricity production: Their 'market value' (defined as the ratio of earnings obtained in the electricity spot market to the average price in the spot market) seems not to permit a full recovery of investment and capital costs of these energy sources. This can be seen in Graph 3. The 'market value' of photovoltaic energy decreases with growing shares of PV installed in Germany[2] and approaches the value of the average base price. Wind energy hardly passes the market value of more than 100% of the average German-Austrian EPEX price, but tends to slightly decrease as well. This means that intermittent renewables - whose main cost arise from investment and capital cost, but who do have no significant marginal cost – suffer from an intrinsic 'non-marketability'. Their own merit-order-effect prevents first of all themselves from profitable business prospects. If the investment in intermittent renewables is to be refinanced and their expansion to be fostered, this cannot be granted by revenues from spot markets[3] and probably neither from future markets who tend to show up the same price levels.

Therefore, the concept of 'market integration' and many of its implications need to be reviewed. Many of its advocates claim for example that their 'market integration' would be able to steer synchronously the quantity of renewables built or to be built and the 'feed-in behaviour' of these power plants. In subjecting intermittent renewables to the development of spot market prices, this would mean to adapt them to the 'needs of the market'. But regarding the shaded prospects of marketability of intermittent renewables, market integration cannot be seen as an instrument which will lead to the system integration of renewables. If Germany as well as all other EU member states wishes to pursue their renewables' and climate protection objectives, other means have to be found to foster the expansion of renewable capacities to be installed.

It is rather an electricity system transformation these states should aim to implement. This new electricity system will consist of three main technical parts: its core part will be constituted by intermittent renewables (wind, photovoltaic and most of the run of the river power plants who are exempt from marginal cost) being backed up by power plants (or grid devices) performing must-run functions necessary to guarantee system stability and the different flexibility options whose function it is to provide the residual energy. There is a strong probability that these

1: Cumulated feed-in data for photovoltaic energy in Germany are published since August 2010 when the total installed capacity reached about 14,7 GW peak. By the end of September 2012, it reached about 31 GW peak.

2: A recently published study from the German energy company MVV comes to the same results. They authors calculated market revenues for wind energy with different levels of CO2 emission certificate prices, with a spread reaching up to 285€2011/ t CO2 in 2050. Even this high price scenario would not guarantee the investment in new wind power plants to be recovered. Cf. Kopp, O./ Eßer-Frey, A./ Engelhorn, T. 2012: Können sich erneuerbare Energien langfristig auf wettbewerblich organisierten Strommärkten refinanzieren?, in Zeitschrift für Energiewirtschaft, DOI 10.1007/s12398-012-0088-y, published online on 27th of July 2012



↑ Graph 3.

↑ Graph 4.

different components will rely on different financing mechanisms. Intermittent renewables will need specific mechanisms who take into account their absence of marginal cost while the other plants will be financed by a mix of sales revenues or revenues from performing the different must run functions (including providing balancing energy) and some revenues issued from future possible capability mechanisms. This is illustrated in Graph 4.

As discussed above, this necessary system transformation needs new mechanisms capable to allocate renewable feed-in electricity if the allocation cannot sufficiently be fulfilled by today's market mechanisms which are principally based on revenues stemming from marginal cost. The actual system merges renewable electricity into the EPEX sales volumes thus taking their 'green' character, but permitting to sell them (regardless of their non-marketability via spot market revenues) at the market clearing price. The electricity purchasing companies therefore do not have to take care of this distinction between 'green' or 'grey' electricity and their principal differences.

This new system architecture –with intermittent renewables as its core – has two further principal characteristics: There is a high need of flexibility to be provided by those power plants which do not depend on a natural energy supply – i.e. the flexibility options – and this need for flexibility should shape the future market rules. These rules should reward those power plants who are able to react conforming to the intermittent renewable energy supply as close to real time as possible.

This need for flexibility and new market rules accompanying them led the authors to try to develop a new EEG-allocation scheme that is intended to incentivize flexibility and make best use of the core competences of the different actors of the electricity system. This new scheme will be presented briefly in the following lines.

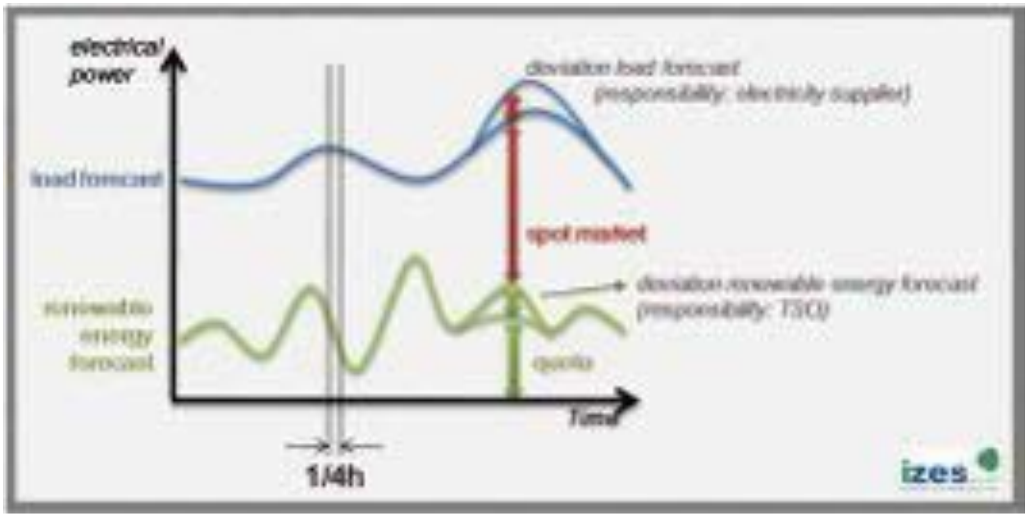
Principally, this new scheme lays the responsibility for the handling of the interaction between intermittent renewables, non-intermittent renewables and conventional power producers on two different 'shoulders': the TSOs and in particular the electricity suppliers. This scheme is illustrated in GRAPH 5.

The TSOs still keep the balancing responsibility and their role as trustees for the financial management of the EEG-account. They would become responsible for the 'physical' part of an EEG power allocation ratio, but on a very short-time basis, i.e. preferably a quarter-of-an-hour. This could take place via a permanent data exchange processes between the Distribution System Operators (=DSO), the TSOs and the suppliers concerning both forecasts of renewable electricity production and load. The final real-time physical allocation ratio could be communicated one or two hours before delivery, just leaving the time necessary for the suppliers to finalize their residual portfolio on the new "residual load spot market". The allocation would thus nearly become a real-time allocation. This allocation ratio could help to decrease balancing requirements. It could be based on renewables' forecasts close to real-time (about four to two hours before delivery) which considerably improves the quality of the forecast. In the actual system, spot-market sales of the EEG power are based on a day-ahead basis with the forecast made in the early morning preceding the day-ahead-auction. It thus covers a 24 hours time span with an additional preliminary of about 16 hours. With this advance of maximum 40 hours before delivery, renewables' forecasts present a higher error probability than those that are made very close to delivery time. In addition, as forecasts are made by one single actor for the whole German territory, the broad geographical basis itself reduces forecast errors by the geographic leveling effect.

The TSOs then transmit the assembled EEG power into the balancing groups of the second bulk of actors whose role would be heavily strengthened with this new scheme: the electricity suppliers. They would be delivered with close to real-time – also on a quarter-of-an-hours-basis – renewables' shares.

In order to complete their delivery portfolio, they can either purchase the remaining quantity on the electricity spot-markets or they can make use of any kind of flexibility option within their portfolio. This can include both additional power produced by decentralized generation capacities or even storage facilities, but also demand side options. Choosing the suppliers as new main actors to handle with the residual load presents the advantage of involving just those actors who have a well identified market competence and a good knowledge of their clients' behavior and load demand.

In general, this new real-time EEG-



Graph 5. →

allocation scheme is supposed to give incentives to render both conventional production devices and electricity market procedures more flexible. As the allocation of the EEG power takes place nearly in real-time, all kinds of market participants should try to adapt their offer and demand on the quarter-of-an-hour basis induced by this new scheme. It is thought to give flexible power plants a market-based back-up and to better integrate ramps of renewable and conventional power plants into the markets whose sales intervals should also become 15 minutes.

This does not necessarily mean that financial products sold at the electricity exchanges' forward trading become obsolete as market participants certainly will still try to achieve price foresight. Part of this 'foresee-ability' could for example partly be achieved with an annual "weighted EEG-full-cost-price" analogous to the current annual financial EEG allocation. As the TSOs would possess real-time data of the quarter-of-an-hourly production by the different types of renewables, they could - on the above cited annual basis - pass these costs to the suppliers. Suppliers would then be obliged to include the share of renewables into their final consumers' bills.

This new scheme would certainly change many aspects of the German electricity sector and have important consequences for the different actors of the German, if not European, electricity system. Even if it may seem to be a specifically German discussion for the moment, the necessity to complement the marginal-cost-based electricity market should sooner or later concern all EU-member states where intermittent renewables form a growing part of the power production.

Its further development and possible implementation needs further research. Some points have already been identified by the authors in discussing with scientific colleagues or experts from the energy business. Principally six considerations emerged from these discussions:

- The need to precise the necessary procedures of data allocation or financial transactions.
- The necessity of new hedging instruments and their costs as well as the financial ability of suppliers of each type and size to handle with a prevalent spot market purchase. Are all suppliers able to handle the new challenges? Will they have to concur or outsource services? Could a mark adjustment begin?
- The necessity of future instruments (regulatory ones or tariff-based ones) capable to give production signals to intermittent renewables once they have obtained the majority of electric power produced
- The ability of this new scheme to include future possibly necessary capacity mechanisms if the existing market design proves to be unable to (re-)finance the costs of flexibility options (both production or storage devices).
- Last but not least the conformity with European Law, especially in terms of non-discrimination of foreign electricity producers whose interests should have to be weighed against a prerogative of national governments to introduce instruments capable to increase renewable electricity supply and hence the general development towards an affordable, sustainable and responsible non-fossil and non-nuclear power generation.

Eva Hauser and Martin Luxenburger are researchers at the IZES (Institut für ZukunftsenergieSysteme, Saarbrücken, Germany), Uwe Leprich is Scientific Director of the IZES.

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