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Sensitivity of electricity prices in energy-only markets with large amounts of zero marginal cost generation

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***Abstract*—This paper explores the sensitivity of electricity prices in energy-only markets with large amounts of wind and solar power. After electricity prices have fallen in many energy-only markets in recent years, the topic has been discussed in many studies with different approaches. The approach in this paper is to perform extensive electricity market simulations. The study is based on the North European power system, and it was carried out using a generation planning model to create reasonable capacity mixes for future, and a unit commitment and economic dispatch model to simulate electricity prices. The results show that the amount of base load generation capacity and overcapacity has a very high impact on electricity prices. The share of wind and solar power and the price of CO_2 also have a clearly detectable, but less significant, impact.**

***Index Terms*--Electricity prices, power system modeling, solar power, unit commitment, wind power**

I. Introduction

In many energy-only markets, electricity prices have fallen in recent years, which has raised concerns about revenue sufficiency of power plants. The concerns are elevated by the apparent increase of zero marginal cost generation (e.g., wind and solar energy, hereinafter referred to as variable generation, VG).

Some studies have implied that wind and solar energy decrease electricity prices. E.g. Liski and Vehviläinen [1] conducted an empirical analysis of the effects of wind power on electricity prices. The analysis provides indication of how different shares of wind power would impact electricity prices in the Nordic electricity market assuming an unchanged thermal generation capacity mix, but the approach falls short of considering how the capacity mix adjusts to the expected changes in the electricity prices. The process is already in progress as older thermal generation units have been retired early as their outlook has become unprofitable.

Accordingly, other studies, which have considered the changing capacity mix, have pointed out that the impact of wind power and solar energy on electricity prices is not as large. Green and Vasilakos [2] postulated that if generators bid their marginal costs, the changes caused by an increasing share of variable generation to the capacity mix will be much more significant than the changes to the prices. According to Green and Vasilakos, the total thermal capacity will decrease only slightly due to the increased wind power capacity, but there will be a shift towards power plants with higher variable costs and lower fixed costs. The study was carried out with a market equilibrium model.

It has also been suggested that wind and solar energy change the volatility of electricity prices, increasing the number of hours of very low and very high prices. Ketterer [3] investigated the impact of wind power generation on the electricity price in Germany. The results from the study showed that wind power reduces the price level but increases its volatility. However, according to Ketterer, the volatility of electricity prices can be decreased with regulatory changes (by increasing the market liquidity by mandating VG to participate in the markets and by providing incentive to make best possible generation forecasts). The study was made using a generalized autoregressive conditional heteroscedasticity (GARCH) model.

Previous studies have also shown that increased power system flexibility can decrease the volatility of electricity prices, although the changes in the capacity mix can be more significant. Green and Staffell [4] analysed the long-term impact of energy storage on electricity prices and generating capacity using an open-source mixed-integer model. The results showed that the price duration curve does not change significantly over the whole year. Instead, generation capacity mix will adjust. Nevertheless, storage cut off some of the very highest prices, and the new equilibrium led to higher prices than before in the near-peak hours. Storage also eliminated some of the hours in which renewables had to be curtailed and consequently increased prices. In [5], Green et al. analysed the long-term impact of hydrogen production via electrolysis on electricity prices. Again, changes in the electricity capacity mix were declared to be much more significant than changes to the prices.

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Palchak and Denholm [6] showed that while introduction of zero-cost generation will always decrease revenue of coal plants in general, changing flexibility can impact the decreased revenues. The study states that in some cases increased flexibility can actually increase revenue despite decreasing actual generation from the coal fleet. The result was explained by reduced curtailment and consequent reduction in the number of hours with a zero price.

The VG forecasts and curtailments also impact electricity prices. Brancucci Martinez-Anido et al. [7] ran several scenarios while varying wind power penetration, forecasts and curtailments using a production cost model of the Independent System Operator in the New England power system. Similarly to the findings in [3], wind power reduced electricity prices and increased electricity price volatility. Over-forecasting wind power increased electricity prices and under-forecasting wind power reduced them. Allowing curtailment increased electricity prices, and for higher wind penetrations it also reduced their volatility. The study suggests that future work could analyse the impact of different generation mixes - such as a higher share of base load generation - on electricity prices.

In the Nordic region, hydropower has a profound impact on the electricity prices. Nordic Energy Technology Perspectives [8] states that historical electricity price fluctuations can be partly explained by the amount of precipitation, CO_2 and fuel prices, and developments in electricity demand. The study shows that demand-side flexibility stabilizes electricity prices and reduces the need for peak power plants. The results of the study showed a steep increase in electricity prices between 2020 and 2030, which was explained with increasing fuel prices and surging CO_2 price. When new investments in transmission capacity were allowed in the model after 2030, electricity prices dropped in Denmark and in other European countries outside the Nordic region, despite the continued rise of the CO_2 price in 2040 and 2050. Nordic Energy Technology Perspectives also highlights that in a market dominated by renewable energy, the occurrence of very low electricity prices and very high prices will be more frequent. The study underlines that the need for base load power plants will decrease significantly, whereas the need for peak power plants and demand response and the value of storage will increase.

It is clear that electricity prices are very sensitive to changes in generation mix, fuel prices, unexpectedly increasing or decreasing demand etc., and there are many uncertainties when predicting what the electricity prices in future may be. However, some indication of the development and the sensitivity of the prices can be given by unit commitment and economic dispatch models as they will optimize the technical and economic task of scheduling power plants to meet electricity demand as long as the capacity mix is reasonably formed. The existing literature lacks studies where the impact of various factors is extensively studied with a combination of capacity expansion planning and unit commitment and economic dispatch simulations. This paper complements the existing literature with results from a large number of simulations from the North European region that show the sensitivity of electricity prices to several different factors.

II. Methodology

A. Approach

The study was based on variations of the future power system in North Europe. The starting point for the study was the existing system with planned additions and retirements, and the approach in the study was as follows:

- Existing capacity was removed from the future scenarios according to their expected lifetimes
- Wind and solar PV capacities were fixed and the rest of the generation and transmission capacity was optimized with a chronological investment planning model
- An operational model was run with modifications to CO_2 prices, fuel prices, demand, base load generation capacity and transmission capacity

First, different shares of wind and solar energy were simulated: 21-23%, 39-40% and 60-61% of total electricity demand. The share of variable generation affected the rest of the capacity mix.

When there is a lot of wind and solar energy in the system, the net load does not leave much room for base load power plants anymore, and an increasingly larger role is left for intermediate and peak load power plants [9].

Sensitivity runs were made by varying the capacity of capital-intensive power plants, using different CO_2 prices and fuel prices, changing the transmission capacities and by unexpectedly decreasing and increasing demand (in this case the capacity mix was not allowed to adjust to the changes in demand). A similar impact would also happen if an excess or a deficit of base load and/or intermediate load power plants develops over a relatively short period of time.

B. Models

The capacity expansion planning part of the study was carried out with the Balmorel model [10]. The model takes into account the chronological variability of electricity and heat loads, wind power and solar PV.

The operational part of the study was carried out using a unit commitment and economic dispatch model WILMAR JMM [11]. The model simulates electricity markets with day-ahead and intraday bidding. It takes into account uncertainties related to wind power and load forecasting. The time resolution in the model is one hour and the optimization horizon is 36 hours. Each country in the model is divided into one or more price regions, and each price region can include several heat areas. In each price region, electricity production (plus import) must equal electricity consumption (plus export), and in each heat area, heat production must be greater or equal to heat consumption every hour.

The operational model also includes a separate water value estimation model to estimate the value of water in hydro reservoirs, which is important in power systems containing large amounts of reservoir hydropower, such as the Nordic power system.

C. *Scenarios and assumptions*

The studied system was North Europe in scenarios for the years 2030 and 2050. The countries included in the modelling are Denmark, Estonia, Finland, Germany, Latvia, Lithuania, Norway, Poland and Sweden.

TABLE I. tabulates assumed electricity demand per country in the 2030 and 2050 scenarios, and TABLE II. tabulates assumed fuel prices in the study. It was assumed that the electricity demand is increasing in the coming decades despite the improvements in energy efficiency, due to electrification of other energy sectors. It is possible, however, that electricity demand is actually not increasing. In this study, future generation mix was optimized in relation to the energy demand, which mitigates the impact of absolute energy demand values. In addition, the primary purpose of the study was not to predict future electricity prices but to show the relative impact of different factors on electricity prices. Furthermore, the results will also show the impact of unexpectedly decreasing and increasing demand.

TABLE I. ELECTRICITY DEMAND

	Demand (TWh)	
	2030	***2050***
Denmark	39.4	43.0
Estonia	9.5	11.8
Finland	96.1	104.9
Germany	556.9	600.0
Latvia	8.1	10.1
Lithuania	12.4	15.5
Norway	133.2	138.5
Poland	170.0	170.0
Sweden	146.5	153.0

TABLE II. FUEL PRICES AND CO_2 CONTENTS

	Fuel price (EUR/GJ)		CO_2 content (kg/GJ)
	2030	***2050***	
Coal	2.9	-	95
Fuel oil	15	-	78
Lignite	2.3	-	101
Municipal waste	0	0	19
Natural gas	9	10	56.9
Nuclear	1	1	0
Peat	3.5	-	107
Shale	1.5	-	106
Straw	4.5	4.5	0
Wood	5	5	0
Wood waste	2.5	2.5	0

It was assumed that carbon-intensive fuels will not be used for electricity and heat production in 2050. The price of natural gas was assumed to increase from EUR 9/GJ to EUR 10/GJ between 2030 and 2050. For CO_2 the base assumption was that the price will be EUR 29/t in 2030 and EUR 49/t in 2050.

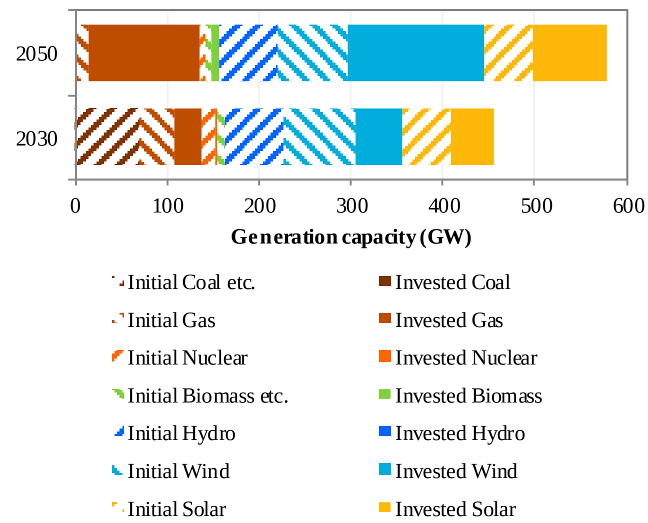

Figure 1 Generation capacity mix assuming a 40% VG share in 2030 and a 60% VG share in 2050 (of annual electricity demand).

Figure 1 shows the future generation mix in the base scenarios, including both the existing capacity that is assumed to stay in operation and the additional capacity that was optimized with the investment model Balmorel in this study. The 2050 generation mix was based on the Windy2050_HeatFlex case in [12]. It was assumed that in 2030 there is still approximately 70 GW of base load coal power in the system. In the 2050 scenario, there was approximately 120 GW of new gas-fired generation capacity. This capacity was mostly composed of gas turbines, but also of gas engines and combined-cycle gas turbine power plants. The base assumption was that the share of variable generation is 40% in 2030 and 60% in 2050 (of annual electricity demand).

It was assumed that on top of the existing transmission capacities between price regions and ENTSO-E development plans there is additional transmission capacity of 7 GW in 2030 and 32 GW in 2050. The additional transmission capacities were optimized with the investment model Balmorel.

III. RESULTS

The results indicate that the amount of base load capacity and overcapacity has the most significant impact on electricity prices. CO_2 price and the share of VG also have a clearly detectable, but less significant, impact. The price axis of each result figure has been limited to EUR 150/MWh for clarity. However, in many of the cases there were a few hours in a year when prices exceeded that value. Most of the figures show simulated electricity prices of Germany, although a couple of the figures also present simulated electricity prices of a few other price regions.

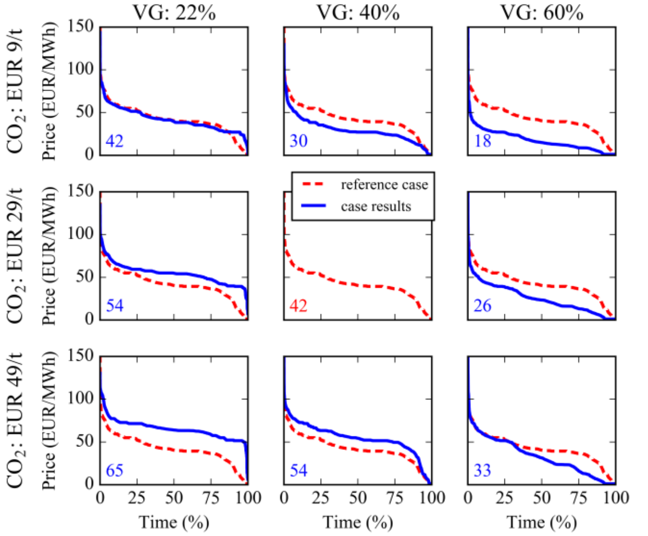

Figure 2 Electricity prices with 2030 capacity mix. Values in the bottom-left corners represent average electricity prices (EUR/MWh). Reference case is the one with EUR 29/t CO_2 price and a 40% VG share.

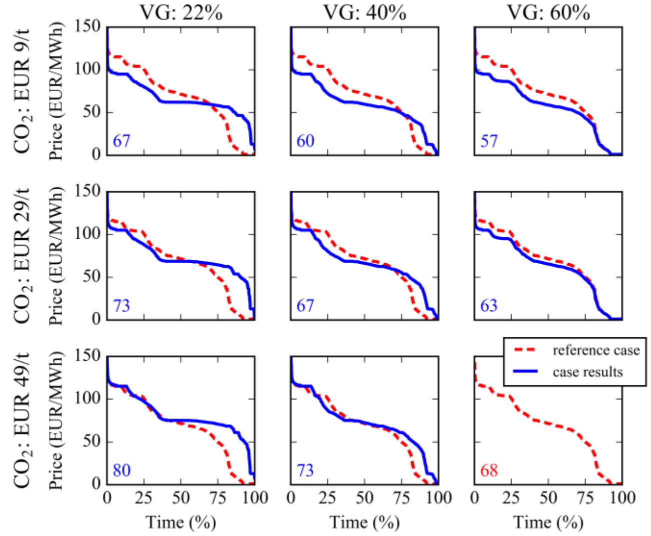

Figure 3 Electricity prices with 2050 capacity mix. Values in the bottom-left corners represent average electricity prices (EUR/MWh). Reference case is the one with EUR 49/t CO_2 price and a 60% VG share.

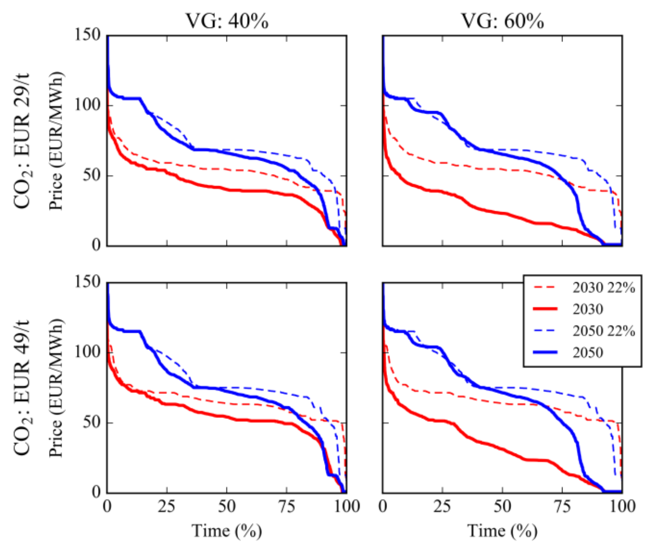

Figure 4 Electricity prices with 2030 and 2050 capacity mixes. Dashed lines represent the corresponding cases with a 22% VG share.

Figure 2, Figure 3, and Figure 4 present variation of electricity prices in 2030 and 2050 scenarios with different CO_2 and VG share assumptions.

The following findings can be made:

- If there is overcapacity in the system (especially the 2030 cases where the share of VG is rather high), the whole electricity price duration curve is depressed by an increasing share of VG, as can be best seen in the middle row of Figure 2.
- An increasing share of VG depresses electricity prices in the right side of the duration curve, which can be seen in the bottom row of Figure 3.
- Increasing cost of CO_2 lifts the left and middle part of the electricity price duration curve, as can be best seen in the right column of Figure 3.
- If the share of VG is rather small (e.g., 22%), the whole electricity price duration curve is lifted by increasing cost of CO_2 – see the left column of Figure 2.
- The impact of the amount of base load generation capacity on electricity prices is very high, which can be seen by comparing 2030 and 2050 results in Figure 4. In the 2030 case, thermal capacity mostly consists of base load power plants, and in the 2050 case, thermal capacity is mostly composed of peak load power plants.

Figure 5, Figure 6, Figure 7 and Figure 8 present electricity prices in 2050 scenarios where thermal generation capacity, transmission capacity, wood price and demand has been altered.

Figure 5 shows a case where new biomass-fired power plant capacity and combined cycle gas turbine power plant capacity has been manually reduced by 20% after investment optimization. In the reference case, these power plants were producing 88 TWh in a year. A 20% reduction would equate 18 TWh, which corresponds to 1.4% of the demand. A smaller amount of biomass-fired power plants and combined cycle gas turbine power plants increased the number of hours of high price and shifted the curve to the right approximately in the left ⅔ of each graph, resulting in increased prices. The change in the capacity did not affect the number of hours of very low price. The results are shown for four example price regions (A: Germany, B: Finland, C: Southern Norway, D: Central Sweden). The impact of reduced capital-intensive generation capacity has similar effects in all four price regions.

Figure 6 shows that a smaller amount of transmission capacity can have different impacts on price duration curve

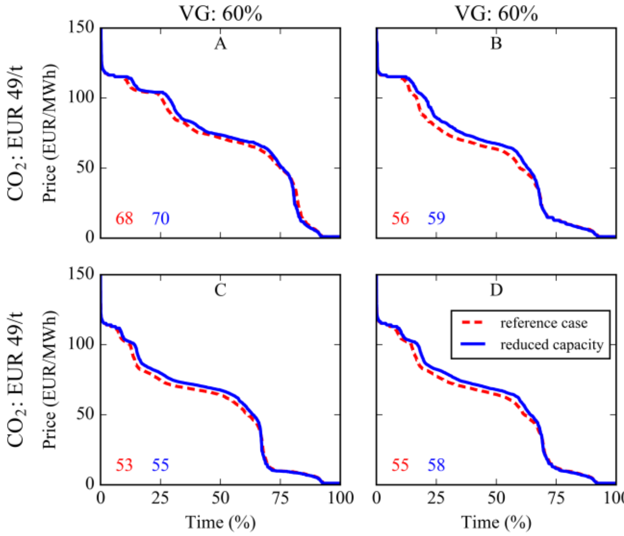

Figure 5 Electricity prices in four price areas (A, B, C and D) with two 2050 capacity mixes – an optimized capacity mix and a mix where optimized new capital intensive generation capacity has been manually reduced by 20%. Values in the bottom-left corners represent average electricity prices (EUR/MWh).

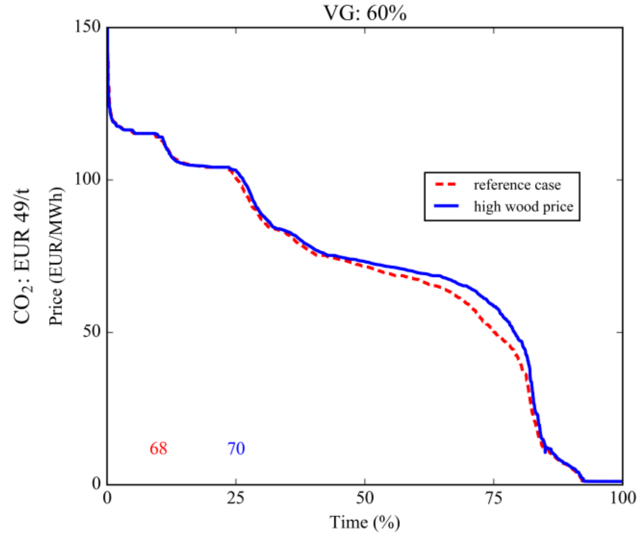

Figure 7 Electricity prices with 2050 capacity mix with two assumptions of the price of wood as a fuel (EUR 5/GJ and EUR 8/GJ). Values in the bottom-left corner represent average electricity prices (EUR/MWh).

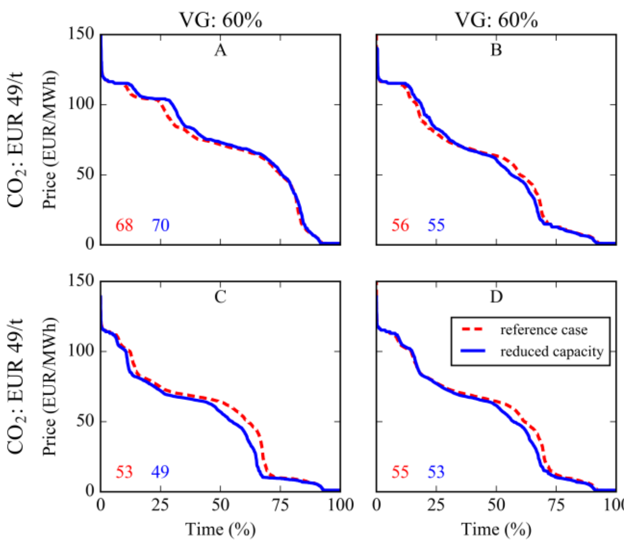

Figure 6 Electricity prices in four price areas (A, B, C and D) with 2050 capacity mix and with two assumptions of additional transmission capacities – optimized additional capacities and additional transmission capacities which have been reduced by 30% from the optimized ones. Values in the bottom-left corners represent average electricity prices (EUR/MWh).

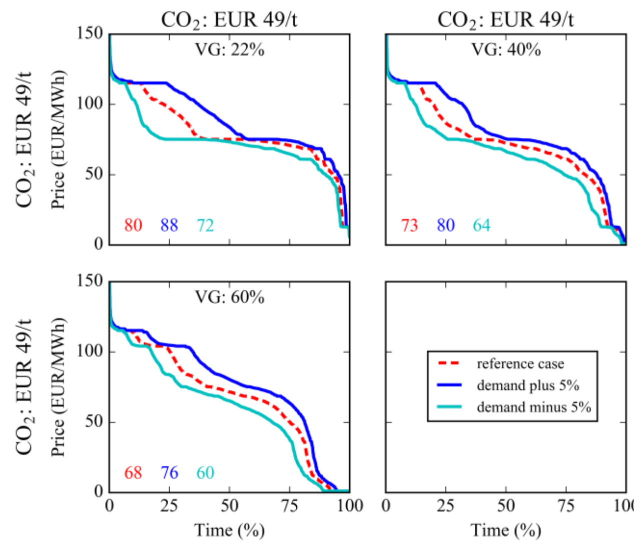

Figure 8 Electricity prices with 2050 capacity mix and with three variations on demand. Values in the bottom-left corner represent average electricity prices (EUR/MWh).

depending on whether the transmission capacity around a price region is more needed for export or import. The price regions are the same as in Figure 5. In price region A, which is using surrounding transmission links more for import, reduced transmission capacity increased the number of hours of high price and shifted the curve to the right in the left half of the curve. In price regions C and D, which are using transmission links more for export, reduced transmission capacity resulted in increased number of hours of very low price. The right half of the curve or almost the whole curve was shifted to the left. In price region B, which uses the surrounding transmission capacity for export and import, the number of hours of both high price and low price increased.

Higher wood price increased the prices in the middle part of the duration curve (EUR 30–70/MWh), i.e., the hours when base load and intermediate load power plants are in the margin (Figure 7).

In Figure 8, scaling the demand 5% upward from the reference case with a 60% VG share increased the number of hours of ca. EUR 120/MWh price and shifted the curve to the right. Scaling the demand 5% downward from the same reference case increased the hours of almost zero prices and shifted the curve to the left. In the 22% VG case, scaling the demand up/down from the reference case affects strongly the upper part of the duration curve (EUR 70-120/MWh). This indicates that also with rather low shares of VG, unexpected changes in the annual demand can have a significant impact on the wholesale prices especially in the price range where intermediate and peak load power plants are in the margin.

IV. Conclusions and Discussion

The North European power system was simulated in 2030 and 2050 scenarios with varying shares of VG (22%–60% of annual electricity demand) and with different assumptions about CO_2 price, fuel prices, base load power plant capacities, transmission capacities, and annual electricity demand. Electricity price results were presented in duration curve format, in decreasing order, for the analysis.

The study showed that as the share of VG is increasing, there will be a reduced need for base load power plants and an increased need for peak load power plants. This result is consistent with previous studies about the adjustment of capacity mix to changes in the net load duration curve due to an increased share of VG.

When large amounts of VG are pushed to power systems that do not have a problem of inadequate generation capacity, very low average electricity prices are likely to occur. The effect is exacerbated if the electricity demand is decreasing. When excess base load generation capacity is retired, average electricity prices are likely to return to higher levels assuming that investors act rationally and invest in more peak load generation capacity and less in base load generation.

In 2030, with too much generation capacity in the system, increasing VG depresses the whole price duration curve. However, in 2050 with more balanced generation mix, predominantly the bottom part of the price duration curve gets depressed with increasing VG. According to this result, an increasing share of VG decreases average electricity prices, which is in line with literature, but additionally, the whole electricity price duration curve does not fall if the rest of the capacity mix is reasonable.

The results also show how higher CO_2 prices would maintain higher electricity prices also with high shares of VG in the system. Furthermore, the influence of CO_2 prices is less pronounced in the 2050 power system with a more balanced capacity structure. The impact of CO_2 prices is larger in 2030 with overcapacity and more carbon-intensive power plants. Conceivably, if the VG share is low, then the CO_2 prices will be higher, as the greenhouse gas reduction targets are more difficult to meet. Similarly, if the VG share is high, then the CO_2 prices may be lower, but not necessarily as the greenhouse gas reduction targets are very stringent. In any case CO_2 prices are driven by policy and the outcomes are highly uncertain especially in the long term.

Varying wood price by 60%, installed capacity of additional capital-intensive thermal power plants by 20% (corresponding to a ca. 1.4% change in annual electricity demand) and additional transmission capacity by 30% had rather small impacts on electricity price duration curves even though these changes were made after the investment optimization. Reduced transmission capacity affected different price regions differently depending on whether the region was more dominantly exporting or importing electricity. Changing the annual electricity demand by 5% had a distinct impact on electricity prices, but perhaps surprisingly, the impact on average electricity prices was very similar between 22%, 40% and 60% VG shares.

The focus in this paper was on the sensitivity of electricity prices in energy-only markets dominated by zero marginal cost generation, such as wind power and solar PV. The results highlighted that electricity prices are very sensitive to the capacity mix and capacity margin, and future electricity prices depend very much on the retirement and investment decisions that producers make together with developments in electricity demand and CO_2 price. The results also showed that VG can support relatively high electricity prices at least in a power system with large amounts of reservoir hydropower. Further research is needed to see how electricity prices differ in power systems that do not contain large hydropower resources.

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