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The Impact of Sector Coupling and Demand-side Flexibility on Electricity Prices in a Close to 100% Renewable Power System

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***Abstract*—Since variable renewables with low marginal costs will constitute the dominant source of power in a fully renewable European power system, wholesale electricity prices could be expected to decrease due to the resulting shift in the marginal cost curve for the power supply. Yet, this effect can be mitigated by the increasing elasticity of demand. We model scenarios of fully renewable European power systems with varying levels of flexibility on the demand side and thermal capacity on the supply side. First, we apply the open-source energy system modelling framework Backbone to optimise investments in new capacities in the scenarios. We enforce the desired level of thermal capacity by adding respective constraints to the model. On the demand side, we include other energy sectors by introducing hydrogen demand, energy demand for electric vehicles, and heating demand for buildings. Using the resulting optimal capacity mixes, we subsequently optimise operations to simulate the European electricity market. As a result, we find that the flexible actors on the demand side become price-setting in a significant number of hours, leading to a stabilisation of wholesale electricity prices in renewable power systems, particularly with very high shares of variable renewables that incur very low marginal costs.**

***Index Terms*—demand response, energy system integration, low-carbon energy system, power system modelling, wholesale electricity prices**

I. Introduction

Since variable renewables with low marginal costs will constitute the dominant source of power in a carbon-free European power system, wholesale electricity prices are likely to decrease in the short term due to the resulting shift in the power supply curve. This decrease is called the merit-order effect, and it has been studied both for wind and solar power in various regions, including Europe [1], Australia [2] and the USA [3].

In the long term, the changes caused by high levels of variable renewables to the capacity mix will also have a significant impact on the electricity prices [4], [5]. Thus, as the rest of the capacity mix adjusts to the high levels of variable renewables, the electricity prices are expected to return to higher levels.

Furthermore, the merit-order effect can be mitigated by energy storage and increasing elasticity of demand [6], [7]. For example, controllable electric heating and cooling and electric vehicles with smart charging can—within their limits—move consumption to time periods with surplus of electricity. In addition, alternative energy sources, for example, fuel-based heaters in buildings with electricity as the main heat source, can further increase the elasticity of demand with a relatively high opportunity cost. However, changing demand patterns and additional flexibility also affect the optimal capacity mix, and thus, the changes to the pattern of prices can be smaller than expected [8].

In this paper, we model scenarios of carbon-free European power systems with varying levels of flexibility on the demand side and thermal capacity on the supply side. First, we apply the open-source energy system modelling framework Backbone to optimise investments in new capacities in the scenarios. Subsequently, we optimise system operations to simulate the European electricity market. We analyse our results with a focus on the marginal value of the energy balance constraint, which under the assumption of perfect competition, we interpret as wholesale electricity prices.

II. Methodology

A. Scenario definitions

We created five scenarios S0–S4 for the pan-European power system, as shown in Fig. 1. The scenarios describe alternative futures with varying levels of renewable energy as well as sector coupling, with the purpose of providing interesting cases from the perspective of market prices.

S0 has a target of ca. 65% of non-thermal renewable energy—namely wind power, solar power and hydropower—in electricity production. The scenario does not include any separately modelled demand-side flexibility options except load shedding of industrial applications. The initial generation mix was based on 2030 national estimates and it includes exogenous capacities of power plants based on fossil fuels,

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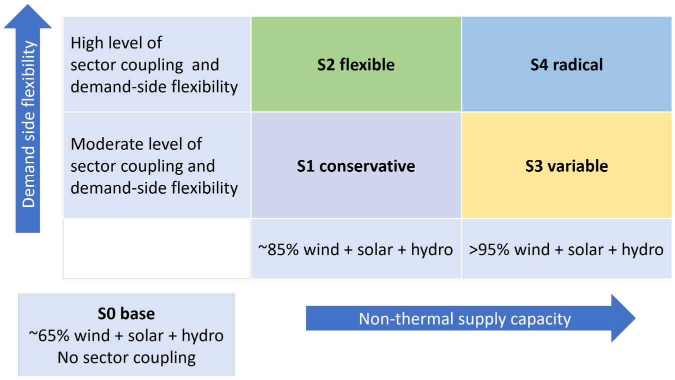

Fig. 1. Scenarios S0–S4 with varying levels of renewable energy as well as sector coupling and demand-side flexibility.

biofuel, waste, nuclear, onshore wind, offshore wind, solar PV, solar CSP, run-of-river hydro, reservoir hydro, pumped hydro, and batteries [9], [10]. Cross-border transmission capacities were set according to 2030 plans [11]. In addition, we allowed endogenous investments in power plants based on biofuel, waste, nuclear, onshore wind, offshore wind, solar PV, solar CSP, batteries, electrolysers, hydrogen turbines, hydrogen storage, and combined-cycle power plants using imported hydrogen [10], [12].

In S1–S4, we assumed all fossil power generation capacity to be decommissioned, increased conventional load, and updated the transmission capacities to 2050 plans [11]. We varied the target share of non-thermal renewable energy in the pan-European region from ca. 85% (S1 and S2) to a minimum of 95% (S3 and S4). In S3 and S4, we further reduced the thermal power generation capacities by 25%, to make room for the additional wind and solar power capacities needed to reach the 95% target. Moreover, additional adjustments were made to reflect renewable targets beyond 2030 in Germany.

In addition, in S1–S4, we included other energy sectors by firstly introducing exogenous time series for hydrogen demand, representing mainly the demand in the industrial sector. In the production and consumption of hydrogen, it was possible to use the flexibility provided by the endogenous investments in electrolysers, hydrogen turbines, and hydrogen storage. Secondly, the traffic sector was represented by consumption and connectivity time series for electric vehicles, which can be charged during hours of lowest prices so long as there is sufficient charge in the fleet to meet the transport needs [13]. Finally, heating demand for buildings was modelled endogenously. It was possible to use the storage capability of the building envelope and domestic hot water tanks [14]. The level of sector coupling and demand-side flexibility was varied by changing the number of electric vehicles and the annual amount of the exogenous hydrogen demand (lower in S1 and S3 and higher in S2 and S4[1]) as well as by adding alternative fuel-based heaters that can be used in buildings during hours of high electricity prices (disabled in S1 and S3 and enabled in S2 and S4).

[1]Hydrogen consumption was 106 TWh or 196 TWh per year and electric vehicles' consumption was 320 TWh or 720 TWh per year in the pan-European region.

B. Backbone Energy System Modelling Tool

The analysis was carried out using the Backbone energy system modelling and optimization tool[2] [15]. Backbone has been designed to be highly adaptable in different dimensions: temporal, spatial, technology representation and market design. The objective function to be minimised in the case studies sums investment and operational costs over the model horizon (each sample s and time interval t) as follows:

$$\begin{aligned} v^{\text{obj}} &= \sum_{\{s,t\}\in ST} p_s^{\text{weight}} \times p_s^{\text{probability}} \\ &\times \left(v_t^{\text{unitVomCost}} + v_t^{\text{balancePenalty}} + v_t^{\text{capacityPenalty}}\right) \\ &+ \sum_{s\in S} p_s^{\text{annuityWeight}} \times \\ &\times \left(v_s^{\text{unitFomCost}} + v_s^{\text{unitInvestCost}}\right) \end{aligned} \tag{1}$$

Parameters are denoted by p and variables by v. The p_s^{weight} parameter represents the weight of the sample, $p_s^{\text{probability}}$ is sample probability, and $p_s^{\text{annuityWeight}}$ is a parameter to ensure that fixed costs are calculated correctly. Variable operational and maintenance costs of units ($v_t^{\text{unitVomCost}}$) include fuel-dependent costs and other variable costs of units. Penalties from violating balance ($v_t^{\text{balancePenalty}}$) and capacity margin ($v_t^{\text{capacityPenalty}}$) equations are also considered. Finally, the fixed operational and maintenance costs ($v_s^{\text{unitFomCost}}$) and investment costs of units ($v_s^{\text{unitInvestCost}}$) are included. The value change resulting from the change of storage states over the simulation is not considered, as storage states are bound between the samples and over the model horizon.

We employed a soft-linking methodology consisting of investment and operational optimisation phases, both implemented in Backbone in linear programming mode (see Fig. 2). The investment optimisation phase represented a year using 5 typical—selected using random sampling [16]—and 2 extreme weeks, while the operational optimisation phase employed a rolling horizon that sequentially optimised the next 24 hours while modelling the remaining 364 days at a coarser resolution in the look-ahead window.

In this analysis, we did not employ many of the features of Backbone, including reserve requirements, inertia constraints, DC power flow, ramping costs, start-up and shutdown costs and trajectories, stochastic production and consumption forecasts, endogenous investments in connections, and pathway modelling to keep the pan-European model computationally tractable.

[2]https://gitlab.vtt.fi/backbone/backbone/

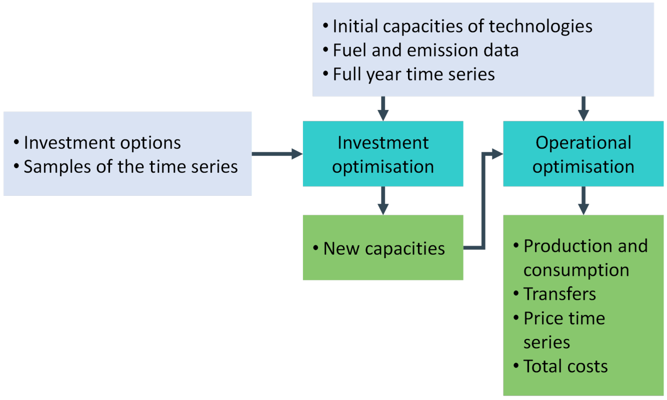

Fig. 2. Soft-linking methodology.

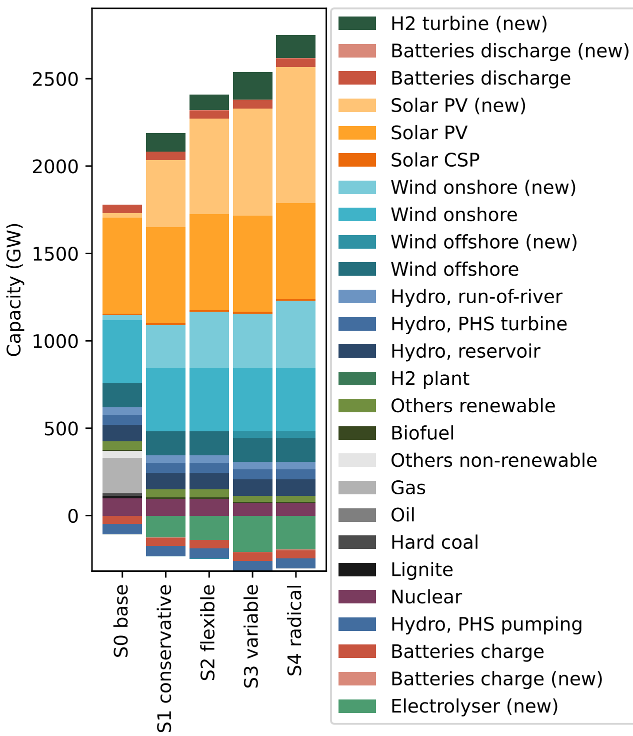

Fig. 3. Exogenous and endogenous capacities.

III. Results

As a result, we first find that the high targets for non-thermal renewables, together with the decommissioned thermal capacity and increased electricity demand, led to high additional wind power and solar PV investments in the pan-European region (Fig. 3). Increasing the target for renewables also increased investments in electrolysers and hydrogen turbines, while additional demand-side flexibility reduced investments in hydrogen turbines.

Fig. 4 shows annual production of the technologies in the pan-European region. In general, the changes between the

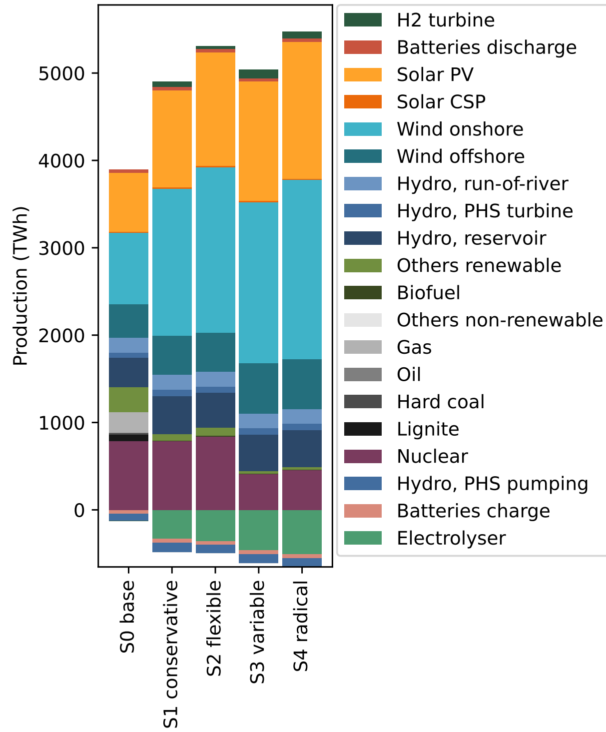

Fig. 4. Annual electricity production.

scenarios reflect the changes in the capacity mix. However, the production of thermal power plants using renewable fuels decreased significantly from S0 to the other scenarios, although the capacity remained the same in S1–S2 and was reduced by only 25% in S3–S4.

Fig. 5 shows how the prices remain at relatively high levels still in the S0 base scenario. The S1 conservative scenario with the 85% target for non-thermal renewables led to more hours with very low prices, but the number of them was reduced when enhancing demand-side flexibility in the S2 flexible scenario. Although the number of hours with high prices was somewhat increased from S0 to S1, their number did not decrease significantly from S1 to S2 in the majority of the countries. This may be explained by a larger capacity margin in the S1 scenario. Additional electricity consumption due to a higher level of sector coupling in S2 diminished the capacity margin.

Compared to S1, the S3 variable scenario with the 95% target for non-thermal renewables resulted in more hours of low prices. Comparison of S2 and the S4 radical scenario shows similar impacts of higher shares of wind and solar energy. Interestingly, S3 and S4 resulted in very similar price duration curves, and only a small reduction in the number of hours with low prices is seen in S4 in some countries. The S3 scenario resulted in large electrolyser, hydrogen turbine and hydrogen storage capacities that provided flexibility similar to the higher amount of sector-coupling technologies in the S4 scenario.

The potentially different capacity margin in the scenarios complicates the comparison. The sensitivity of the electricity prices to the capacity margin was further analysed by varying the exogenous thermal capacities in S3 and S4 (see Fig. 6). In the original S3 and S4 scenarios, the exogenous thermal capacities were 75% of the capacities in S1 and S2, but the additional sensitivity cases contained 50% and 100% of the S1 and S2 capacities. The impact of the amount of exogenous thermal capacity on the prices is clear, more capacity pushing down the prices. In general, higher level of sector coupling and enhanced demand-side flexibility slightly decreased the number of hours with the lowest and highest prices, although opposite impacts were also observed in a small number of countries.

The analysis had limitations that could have a large impact on the observed prices. For example, the low prices could drive even more non-fossil thermal generation out of the system and the prices could then stabilise at levels where these generators are able to recover their operational and fixed costs. Alternatively, the price level could be set by the break-even prices of new VRE generation. Furthermore, the study was based on a single year time series—there should be considerable variation in prices between years with the given capacity mix and also the investments would be affected by longer time series.

IV. Conclusion

Using the energy system modelling framework Backbone, we simulated wholesale electricity prices in pan-European scenarios with a target of 65%–95% of electricity from non-thermal renewable energy sources and with two assumptions on the level sector coupling and demand-side flexibility. We observed that, while wind and solar energy tend to increase price variability, sector coupling and demand-side flexibility can help stabilise the prices. However, the assumptions on thermal capacities were so high that even after removing all fossil power plants, increasing conventional load, and adding flexible loads, introducing 85% and especially 95% targets for non-thermal renewables led to a relatively high number of hours with very low prices. The sensitivity of the prices to the capacity margin was high as demonstrated by the simulations that varied the exogenous thermal capacity in the scenarios.

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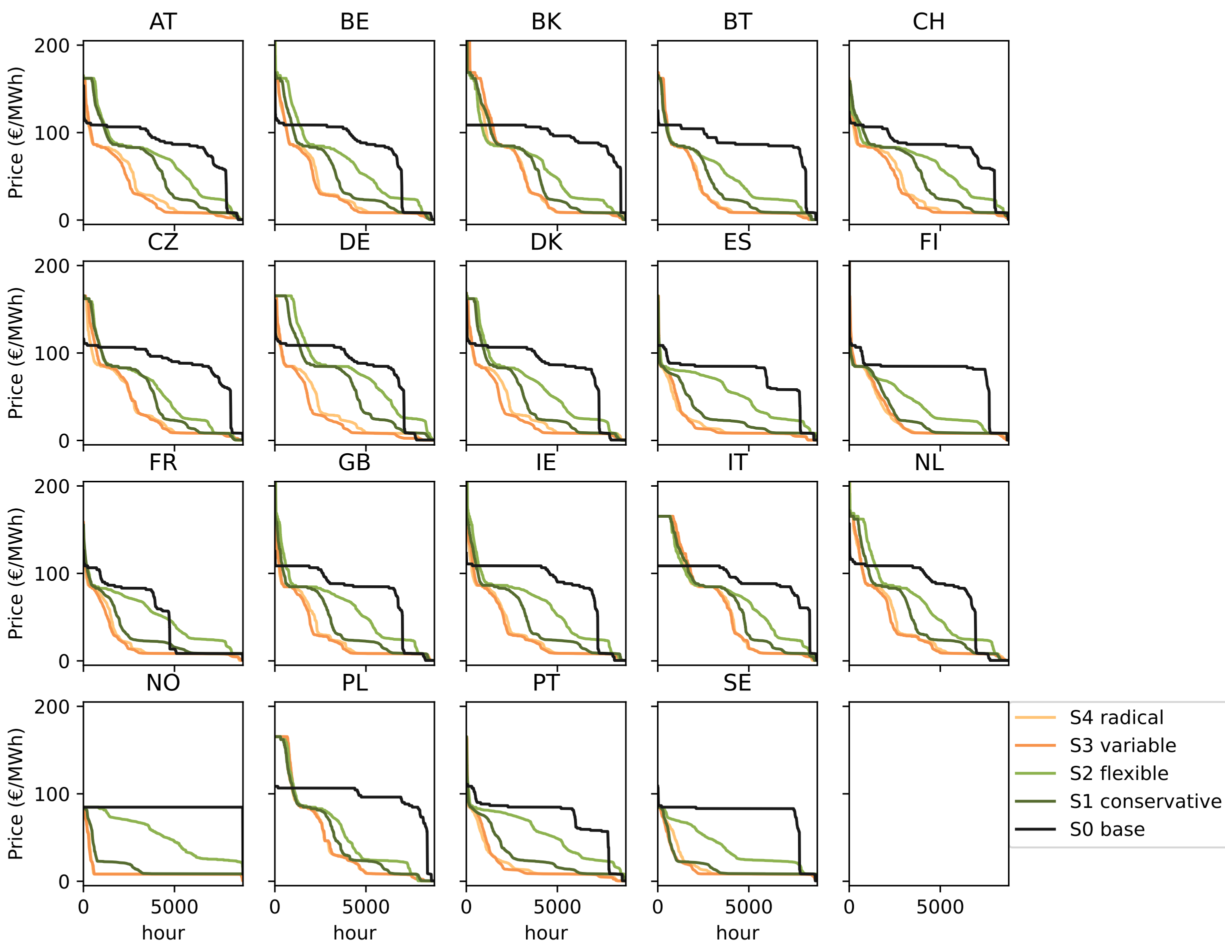

Fig. 5. Impact of the amount of wind and solar energy as well as sector coupling and demand-side flexibility on electricity prices, shown as duration curves in modelled countries and regions.

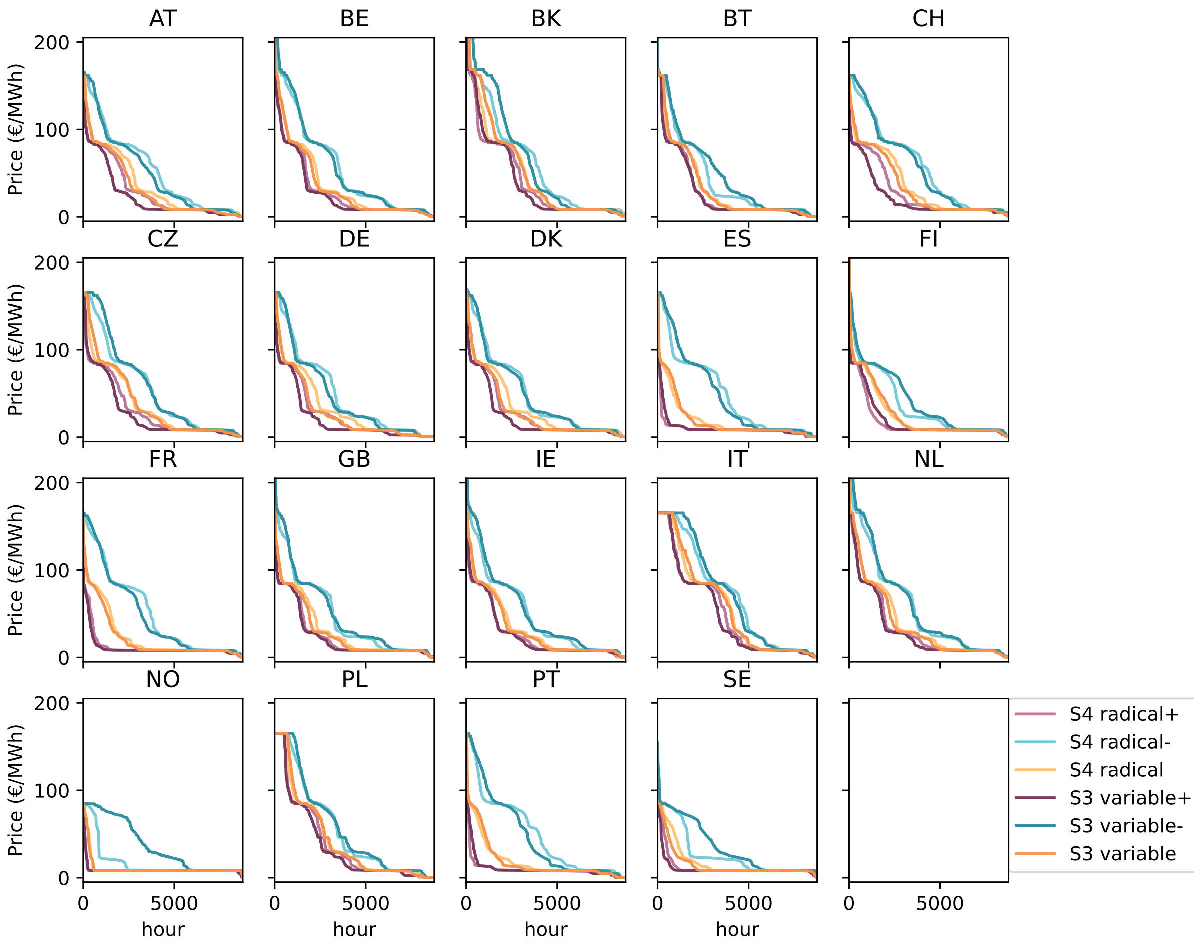

Fig. 6. Sensitivity of electricity prices to the amount of exogenous thermal capacity (highest in the scenarios marked with '+' and lowest in the scenarios marked with '-'.