Power System Transformation toward Renewables: Investment Scenarios for Germany

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Executive Summary

Germany is experiencing substantial growth in renewable energy. According to the Federal German Energy Concept, which is a cornerstone of Germany's Energiewende, renewables should account for at least 35% of gross power demand supplied by 2020, 50% by 2030 and 80% by 2050. Due to limited potentials of hydro power and biomass in Germany, this implies substantial growth of renewable electricity generation from wind and solar power. These sources are characterized by fluctuating feed-in patterns, an uneven geographical distribution of potentials, and a low capacity credit. Supply from wind and solar power has to be balanced with demand at all network nodes at all times. This poses challenges for the overall power system. Several strategies are under discussion, including flexible thermal power plants, power storage, and transmission grid expansion.

We carry out a techno-economic model analysis to determine investment scenarios for the German power system with increasing shares of renewables. Investments into thermal power plants, pumped hydro storage, and the transmission grid are optimized simultaneously from the perspective of a central planner. As for the spatial resolution, we model the German high-voltage transmission network on a nodal level. We look at the year 2024, in which the remaining nuclear capacity in Germany will be completely phased out, and also at 2034,

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which represents a longer-term system transformation toward fluctuating renewables. We base our calculations on scenarios of the German Network Development Plan, but do not primarily aim to confirm or disconfirm its outcomes. Rather, we are interested in the intricate interaction of investments into power plants, storage, and transmission as well as their impact on power plant operation and system costs.

We use an integrated optimization model for dispatch, transmission, and investments that includes a nodal disaggregation of the high-voltage transmission network and applies the "DC load flow" approach. Endogenous investments in generation, storage, and transmission infrastructure are characterized by integer variables. The model decides simultaneously on all investment option considering endogenously the tradeoffs between them. The objective value is total system costs, which consist of annualized fixed costs for new investments and variable generation costs (fuel and CO_2) of existing and new conventional power plants, scaled to one year. The model thus determines an investment mix that minimizes overall system costs for one static year.

We examine five scenarios for the years 2024 and 2034 that include different assumptions on the available infrastructure options and the costs of renewable curtailment: a "Reference scenario" without additional constraints; two "Decreased curtailment" scenarios, in which curtailed renewable generation is penalized with 100 EUR/MWh and 1000 EUR/MWh, respectively, in the objective function; a "No network extension" scenario that does not allow any investments in transmission lines; and an "Exogenous storage" scenario that assumes that pumped hydro storage capacity will be built according to Network Development Plan projections.

Based on the numerical results, we suggest several conclusions. First, the requirement for investments into generation, storage, and transmission increases through 2024 within the context of an aging thermal power plant fleet and a strong capacity build-up of fluctuating renewable generators. To some extent, investments into CCGT plants, pumped hydro storage, as well as AC and DC transmission lines may be substituted against each other. In a cost-minimizing system, however, a mix of all investment options is required in the longer run. Considerable investments into CCGT plants are found in all scenarios. Importantly, these generation capacities have to be placed in specific regions. In 2024 most new CCGTs are located particularly in southern Germany, where nuclear capacities are phased out. 2034 results indicate that additional CCGTs in western Germany replace hard coal and lignite capacities. In reality, the current German market design provides little incentives for system-optimal power plant placement, and policy makers should work toward proper regional investment incentives.

As for pumped hydro storage, our model determines rather small capacity requirements by 2024, and moderate investments by 2034. Nonetheless, pumped hydro storage appears to be a no-regret option from a system perspective: overall system costs of the scenarios with more or less storage differ only slightly, while pumped hydro storage facilities at the same time have additional system values related to the provision of reserves and other ancillary services, which are not included in the optimization. Such additional benefits may outweigh the slightly higher system costs of the exogenous storage scenarios; a detailed analysis of this issue is left for future research. In any case, given that our longer-term scenarios indicate growing storage requirements—even without considering additional system values—early planning for new pumped hydro storage facilities appears to be favorable.

Regarding transmission investments, we identify several AC lines that are to be expanded in virtually every scenario. It may be favorable to make developing these projects a priority. Making definitive statements on the requirement or the advantageousness of individual AC or DC connections, however, is beyond the scope of this analysis; moreover, line investments strongly depend on future power plant and storage deployments, both of which are uncertain in the context of a competitive power market. In any case, some network extensions are required in most cases analyzed here.

In general, most investment options analyzed here face long lead times, especially storage and transmission investments. With the perspective of a long-term transition toward a largely renewable-based system, it appears to be reasonable to administratively prepare such infrastructure projects early on. This argument is even more valid if there is a political intention to reduce renewable curtailment, which may, among other reasons, be motivated by climate policy concerns. With the perspective of further increasing renewable shares after 2034, early planning with priority for renewable integration as in the decreased curtailment scenarios may thus be beneficial.