ELECTRICITY GENERATION, STORAGE AND TRANSMISSION FOR CENTRAL EUROPE IN 2035: TRADE-OFFS BETWEEN COST-OPTIMAL AND NEAR-OPTIMAL SCENARIOS

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Overview

The future transition of the European electricity system is deeply uncertain as it depends on multiple factors that are difficult to predict, such as technology innovation, policy, and socio-economic dynamics. Electricity system optimization models are typically used to probe various electricity system layouts under assumed scenarios [1]. However, basing policy advice on one or a handful of optimal scenarios can be misleading as they largely depend on the modeler's assumptions of how the electricity system might develop. Cost-optimal scenarios might be also deemed unsuitable by policymakers due to preferences that are difficult to formalize in models, such as public acceptance [2], equity issues [3], and economic impacts [4]. Alternative, costlier scenarios might exist that bypass such concerns.

A way to tackle deep uncertainty, reduce modeler's bias, and provide alternative scenarios from electricity system optimization models to policymakers is a method called Modeling to Generate Alternatives (MGA) [5]. This method systematically explores maximally different scenarios from the model with cost-optimal or near-optimal cost. By modeling large numbers of scenarios with MGA, modelers can visualize the trade-offs between investment choices and other concerns, highlight no-regret and must-avoid options, and overcome modeler's bias as each MGA scenario is computer-generated. In this study, we apply MGA to investigate the trade-offs between conventional and renewable electricity generation, transmission and storage capacity, total system costs, regional equity in terms of generated electricity, and greenhouse gas emissions. We soft-link two optimization models with high spatial (NUTS-3 regions) and high temporal resolution (hourly) for investigating cost-optimal and near-optimal scenarios for six countries in Central Europe in 2035: Austria, Denmark, France, Germany, Poland, and Switzerland.

Methods

In our approach, we soft-link two existing optimization models called EXPANSE [3,5] and PyPSA [6]. EXPANSE is a spatially explicit (650 NUTS-3 regions), bottom-up, technology-rich, single-year electricity system model with annual resolution and it applies MGA to compute near-optimal scenarios. The principle of MGA is to relax the cost-optimal scenario with an acceptable relative cost increase called "slack" and to search the near-optimal space for scenarios that are maximally different. In this study, we vary the "slack" between 0-10% above cost-optimal total system costs. PyPSA is an electricity system model without MGA with lower spatial resolution (100 nodes) and it complements EXPANSE with hourly computations of variable renewable generation, storage and transmission lines.

We model wind turbines (offshore and onshore), solar PV (rooftop and open-field), hydro (large dams, large run of river and small hydro), nuclear, oil, gas, hard coal, lignite, geothermal, biomass (biogas, woody biomass, and biomass waste), battery, pumped hydro and hydrogen storage, and transmission lines (HVDC and HVAC). All 100 MGA scenarios are subject to electricity generation, storage, and transmission constraints, and are set to achieve the renewable capacity targets derived from each country's nationally determined contributions (NDCs) for 2030. Due to the computational intensity of modeling transmission lines, we simplify the actual network layout of the region from roughly 2'000 nodes to 100 nodes by using k-means clustering and apply 3-month rolling-horizon optimization technique in order to computationally accommodate the large number of MGA scenarios. Each MGA scenario requires on average 2 hours of computation time, 20 GB memory and 16 CPU cores to solve in a fully parallelized workflow.

Results

Figure 1 shows the spread of electricity generation, capacity of power plants, storage, and transmission, as well as system costs and greenhouse gas emissions in all 100 MGA scenarios and three selected scenarios: the least-cost scenario, the scenario that is most regionally equitable (even) in terms of generated electricity, and the scenario that assumes the continuation of the current status (2018). We find that the technologies with the largest near-optimal feasible range in terms of electricity generation are wind (offshore and onshore), solar PV (rooftop and open-field), nuclear, hard coal, lignite, and gas. In comparison, the near-optimal feasible range for biomass, geothermal and hydro power plants is far narrower, due to stricter spatial constraints and lower remaining economically exploitable potential.

Electricity generation costs are consistently the main cost component across all 100 MGA scenarios (annualized capital and operation costs of 112-120 billion EUR/year). Storage costs vary significantly (8-17 billion EUR/year), while transmission costs are consistently low (5-6 billion EUR/year). Rooftop solar PV leads to large increases in electricity generation costs, while onshore wind leads to large increases in storage and transmission costs. In comparison, offshore wind leads to lower increases in electricity generation, storage and transmission costs due to a significant expected decrease in offshore wind capital costs until 2035 and due to relatively high and steady availability. Amongst conventional power plants, reduction of gas capacity leads to the largest increase in costs for storage, transmission and the system as a whole.

Reduction in greenhouse gas emissions from electricity generation can vary significantly between 10-60% compared to the current status (2018). We find that solar PV (open-field and rooftop) and wind (offshore and onshore) have the highest potential to significantly reduce greenhouse gas emissions at still reasonable costs.

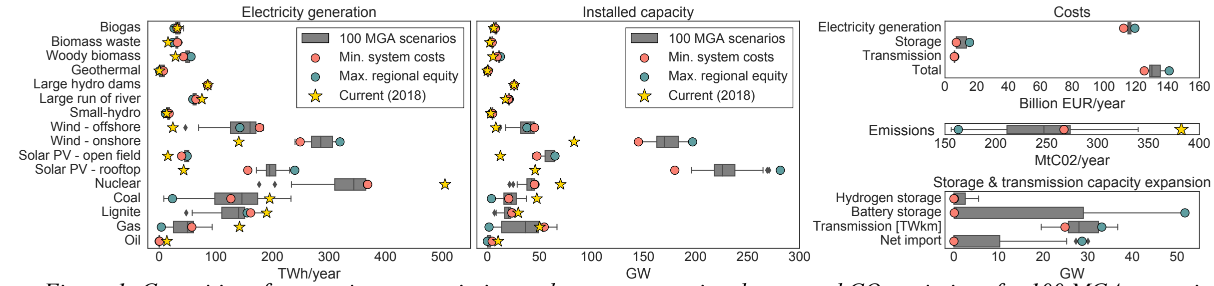

Figure 1: Capacities of generation, transmission and storage, associated costs and CO_2 emissions for 100 MGA scenarios

Battery storage is preferred over hydrogen storage due to lower expected costs in 2035 and required capacities range between 0-55 GW and 0-6 GW, respectively. Transmission capacity expansion cannot be avoided for any of the scenarios and ranges between 20-38 TWkm. Net import capacity expansion ranges between 0-29 GW. Onshore wind capacity induces investment in both battery and hydrogen storage capacity, as well as transmission and net import capacity. In comparison, rooftop solar PV requires less additional transmission, net import and storage capacity due to higher correlation with electricity demand. Additional storage, transmission, and net import capacity can be substituted with existing gas, coal and oil capacity (at a significant cost of negative impact on climate change), but not with nuclear due to stricter ramping constraints and not with lignite that is located only in few regions.

Figure 2 shows two spatially explicit MGA scenarios of our studied region for electricity generation, storage, and transmission: the scenario with the lowest system costs and the scenario that is most regionally equitable in terms of generated electricity. The least system cost scenario is largely dependent on electricity generated from offshore wind, nuclear, lignite, coal and gas, while the most equitable scenario rather combines solar PV and onshore wind with battery storage. In both cases, transmission capacity expansion is required especially at the borders of all countries.

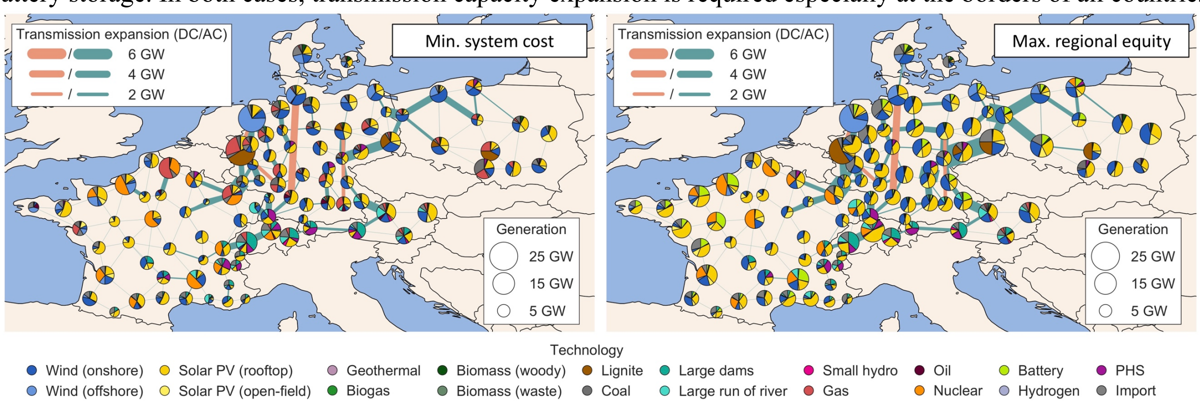

Figure 2: Spatial visualization of two scenarios: the least system costs and the highest regional equity

Conclusions

Our analysis indicates that, when looking through 100 MGA scenarios in six countries of Central Europe, there are significant trade-offs between conventional and renewable electricity generation, transmission and storage capacity, total system costs, regional equity, and greenhouse-gas emissions. We find that rooftop solar PV is a key technology to significantly increase regional equity at a trade-off of high electricity generation costs. Onshore wind leads to relatively high storage and transmission costs, but low electricity generation costs. Offshore wind is a no-regret option with relatively low increases in electricity generation, transmission and storage costs. Hydrogen storage is required for scenarios with very high shares of offshore and onshore wind, but battery storage is generally preferred over hydrogen due to lower expected costs in 2035. Reduction in gas capacity significantly increases the costs of storage and transmission for scenarios with high shares of electricity from solar PV and wind.

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