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Costs of regional equity and autarky in a renewable European power system

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ABSTRACT

The spatial distribution of infrastructure plays a key role in shaping the levels of social acceptance in future energy systems. Here, I evaluate the cost impact and changes in the system composition when development of infrastructure is more evenly shared among countries and regions in a fully renewable European power system. I deliberately deviate from the resource-induced cost optimum towards more equitable and self-sufficient solutions in terms of power generation. The analysis employs the open optimization model PyPSA-Eur. I show that purely cost-optimal solutions lead to very inhomogeneous distributions of capacities, but more uniform expansion plans can be achieved on a national level at little additional expense below 4%. However, completely autarkic solutions, without power transmission, appear much more costly across a variety of technology cost assumptions.

1. Introduction

Optimizing for an unmitigated least-cost renewable power system was observed to entail a very heterogeneous distribution of electricity generation in relation to demand when compared to national imbalances reported by ENTSO-E for 2018 (Fig. 1) [1]. The system is dominated by many distinct net importers and exporters, whereas few supply just their own demand. This raises concerns about distributional equity, which in this paper describes how evenly generation capacities are distributed relative to the regional demands.

Narrowly following the cost optimum risks inequitable outcomes and public headwind, bearing the potential of decelerating the energy transition. Particularly wind farms and transmission lines spark local opposition, which was found to be best counteracted by including the public in the planning process and by sharing profits [2]. Vice versa, also the absence of investments may have a detrimental impact on local communities.

Beyond the spatial distribution of generation capacities, numerous other equity principles exist, which I do not cover [3]. Equity metrics can also relate to temporal, income, racial, labor and environmental aspects [4–8]. Recent developments of pan-continental models with growing sub-national detail raise the need for recognising their regional implications [6,9]. However, such aspects are challenging to assess in endogenous modelling, and analyses have been limited to ex-post analysis [6]. Enhanced collaboration between social scientists and energy modellers has been encouraged [10].

Moreover, there is a trend towards discussing energy autarky, i.e. the ability to operate regions partially or completely independently [11,12]. Positive associations with autonomy, control and independence drive aspirations for self-sufficiency for individuals and municipalities alike, resulting in a higher willingness to pay and greater support for projects [12–15]. The debate also revolves around the resilience of more decentralised systems [16]. The primary resource-based feasibility of autarkic systems on different spatial levels was evaluated in Tröondle et al. [17]. A high population density was sometimes found to be a limiting factor for small autarkic systems. Weinand et al. found that about half of the 11,300 municipalities in Germany have sufficient potentials to become off-grid municipalities [18].

Further related work has assessed the benefit of transmission capacities between countries [19] and more heterogeneous distributions of generation capacities [20]. It has moreover been evaluated what range of similarly costly but possibly more socially acceptable power systems can be realised [21] and what costs are incurred by reducing eligible potentials [22]. Previous work on distributional equity regarding power generation has however mostly covered only a single country and neglected the variability of renewable generation and demand, as well as the interaction between storage and transmission infrastructure [3, 23].

Two very recent studies have remedied concerns about the spatial scope and temporal resolution [24,25]. However, while Tröndle et al. [24] evaluate continental, national, and regional scales of balancing and supplying electricity demands based on greenfield grid expansion, which gives a slight cost advantage to autarkic solutions despite the high spatial resolution of 500 nodes, Sasse and Trutnevyte [25] plan

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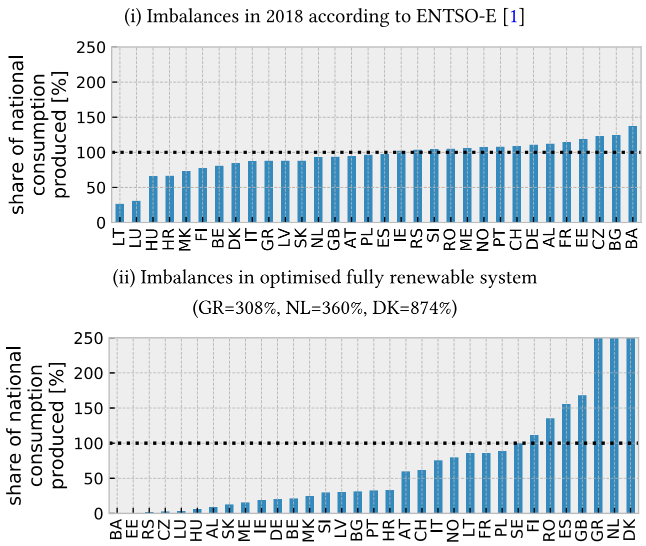

Fig. 1. Imbalances observed in 2018 and in cost-optimised renewable system using reference technology cost projections from Table 1.

Table 1
Technology cost assumptions used with reference scenario and uncertainty using optimistic and pessimistic assumptions based on the Danish Energy Agency [28]. The fixed power-to-energy capacity ratio is 6 h for batteries and 168 h for hydrogen storage. Utility-scale and rooftop PV are evenly split. A uniform discount rate of 7% (only for rooftop PV it was set to 4%) was applied to determine the annuities. The onl A more detailed listing of techno-economic assumptions is provided in Table A.2.

Technology	Lower Annuity	Upper Annuity	Reference	Unit
Onshore Wind	73	109	109	€/kW/a
Offshore Wind	146	201	169	€/kW/a
Solar	36	55	55	€/kW/a
Battery	30	133	133	€/kW/a
Hydrogen	111	259	224	€/kW/a

generation and balancing infrastructure only consecutively, which neglects decisive dependencies between the siting of generation capacity and the placement of storage or transmission reinforcement.

In this contribution, I explore at what cost more evenly distributed, or even autarkic power supply could be achieved in Europe, regarding both countries and smaller regions. While taking account of the existing grid infrastructure, we consider trade-offs between generation, storage and transmission infrastructure siting by simultaneously co-optimizing their capacity expansion.

2. Model Setup

I use the open European electricity transmission system model PyPSA-Eur with 200 nodes and 4380 snapshots, one for every 2 h in a year [26]. I solve a long-term power system planning problem which seeks to minimise the total annual system costs, comprising annualised capital costs $c_\star$ for investments at locations i in generator capacity $G_{i,r}$ of technology r, storage capacity $H_{i,s}$ of technology s, and transmission line capacities F_ℓ, as well as the variable operating costs $o_\star$ for generator dispatch $g_{i,r,t}$:

$$\min_{G,H,F,g} \left\{ \sum_{i,r} c_{i,r} G_{i,r} + \sum_{i,s} c_{i,s} H_{i,s} + \sum_{\ell} c_\ell F_\ell + \sum_{i,r,t} w_t o_{i,r} g_{i,r,t} \right\} \tag{1}$$

where the snapshots t are weighted by w_t such that their total duration adds up to one year. The objective is subject to a set of linear constraints that define limits on (i) the capacities of infrastructure from geographical and technical potentials, (ii) the availability of variable renewable energy sources for each location and point in time, and (iii) linearised multi-period optimal power flow (LOPF) constraints including storage consistency equations, which I describe in more detail in the following. Overall, the problem classifies as a linear problem (LP) with exclusively continuous variables.

The capacities of generation, storage and transmission infrastructure can be limited to their geographical potentials from above and existing infrastructure from below:

$$\underline{G}_{i,r} \le G_{i,r} \le \overline{G}_{i,r} \quad \forall i, r \tag{2}$$

$$\underline{H}_{i,s} \le H_{i,s} \le \overline{H}_{i,s} \quad \forall i, s \tag{3}$$

$$\underline{F}_\ell \le F_\ell \le \overline{F}_\ell \quad \forall \ell. \tag{4}$$

Here, I assume that generation and storage capacities are built from zero, except for existing hydro-electric infrastructure which is assumed not to be extendable. The capacities for wind and solar are restricted to their respective geographical potentials derived from land eligibility constraints and maximal deployment densities. Existing transmission capacities can be continuously reinforced but not removed. Furthermore, I assume no upper bounds for transmission lines or storage units.

The dispatch of a renewable generator is constrained by its rated capacity and the time- and location-dependent availability $\overline{g}_{i,r,t}$, given in per-unit of the generator's capacity:

$$0 \le g_{i,r,t} \le \overline{g}_{i,r,t} G_{i,r} \quad \forall i, r, t \tag{5}$$

The dispatch of storage units is described by a charge variable $h^+_{i,s,t}$ and a discharge variable $h^-_{i,s,t}$, each limited by the power rating $H_{i,s}$.

$$0 \le h^+_{i,s,t} \le H_{i,s} \quad \forall i, s, t \tag{6}$$

$$0 \le h^-_{i,s,t} \le H_{i,s} \quad \forall i, s, t \tag{7}$$

The energy levels $e_{i,s,t}$ of all storage units are linked to the dispatch by

$$\begin{aligned} e_{i,s,t} = {} & \eta^{w_t}_{i,s,0} \cdot e_{i,s,t-1} + w_t \cdot h^{\text{inflow}}_{i,s,t} - w_t \cdot h^{\text{spillage}}_{i,s,t} + \eta_{i,s,+} \cdot w_t \cdot h^+_{i,s,t} \\ & - \eta^{-1}_{i,s,-} \cdot w_t \cdot h^-_{i,s,t} \quad \forall i, s, t \end{aligned} \tag{8}$$

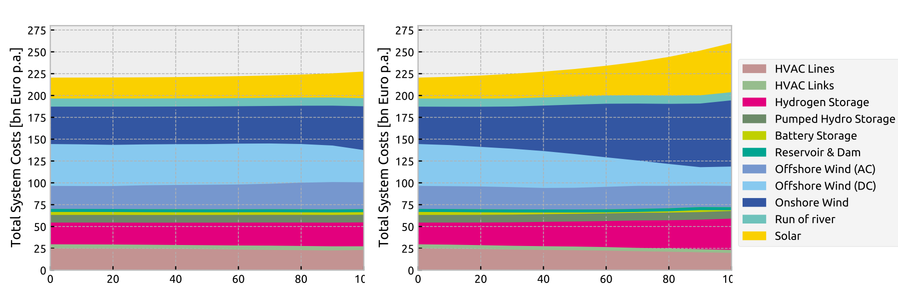

Fig. 2. Sensitivity of system cost and composition to nodal and country-wide equity requirements.

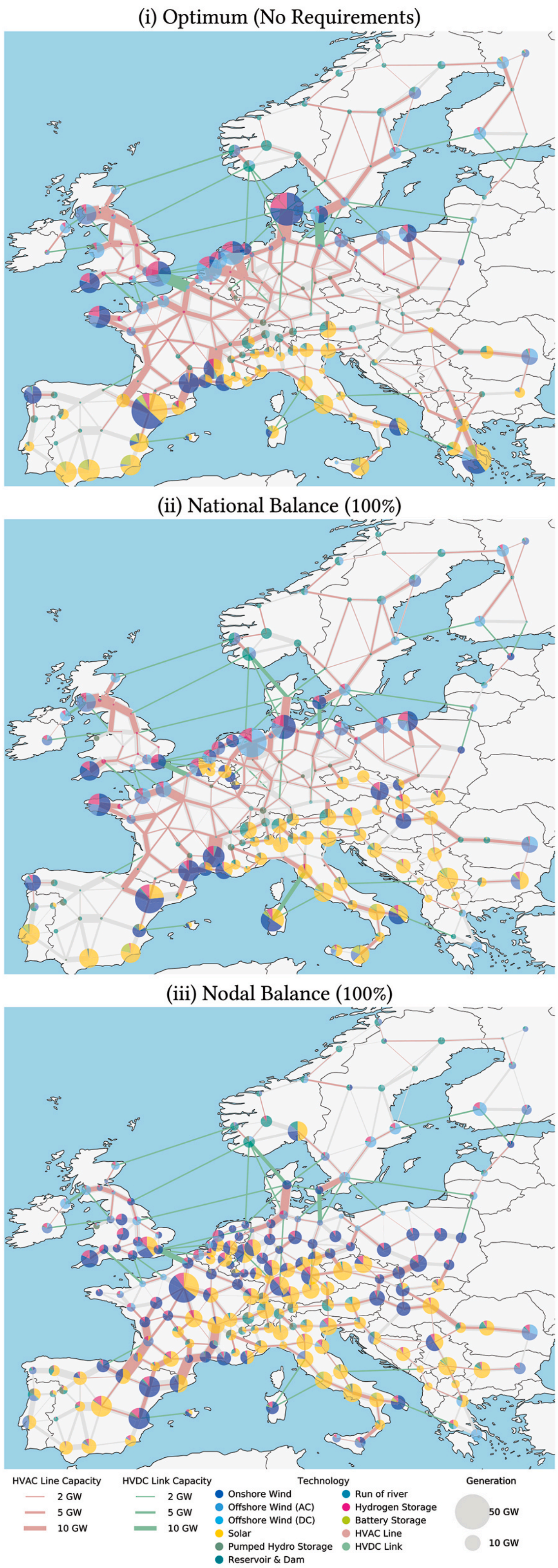

Fig. 3. Maps of cost-optimal system layouts for different equity requirements.

Storage units can have a standing loss $\eta_{i,s,0}$, a charging efficiency $\eta_{i,s,+}$, a discharging efficiency $\eta_{i,s,-}$, natural inflow $h^{\text{inflow}}_{i,s,t}$ and spillage $h^{\text{spillage}}_{i,s,t}$. The storage energy levels are assumed to be cyclic and are constrained by their energy capacity

$$e_{i,s,0} = e_{i,s,T} \quad \forall i,s \tag{9}$$

$$0 \leq e_{i,s,t} \leq \overline{T}_s \cdot H_{i,s} \quad \forall i,s,t. \tag{10}$$

To reduce the number of decision variables, I link the energy capacity to power ratings with a technology-specific parameter $\overline{T}_s$ that describes the maximum duration a storage unit can discharge at full power rating.

Kirchhoff's Current Law (KCL) requires local generators and storage units as well as incoming or outgoing flows $f_{\ell,t}$ of incident transmission lines ℓ to balance the inelastic electricity demand $d_{i,t}$ at each location i and snapshot t

$$\sum_r g_{i,r,t} + \sum_s h_{i,s,t} + \sum_\ell K_{i\ell} f_{\ell,t} = d_{i,t} \quad \forall i,t, \tag{11}$$

where $K_{i\ell}$ is the incidence matrix of the network.

Kichhoff's Voltage Law (KVL) imposes further constraints on the flow of AC lines. Using linearised load flow assumptions, the voltage angle difference around every closed cycle in the network must add up to zero. We formulate this constraint using a cycle basis $C_{\ell c}$ of the network graph where the independent cycles c are expressed as directed linear combinations of lines ℓ [27]. This leads to the constraints

$$\sum_\ell C_{\ell c} \cdot x_\ell \cdot f_{\ell,t} = 0 \quad \forall c,t \tag{12}$$

where x_ℓ is the series inductive reactance of line ℓ. Controllable HVDC links are not affected by this constraint.

Finally, all line flows $f_{\ell,t}$ must be operated within their nominal capacities F_ℓ

$$|f_{\ell,t}| \leq \overline{f}_\ell F_\ell \quad \forall \ell,t, \tag{13}$$

where $\overline{f}_\ell$ acts as a per-unit buffer capacity to protect against the outage of single circuits, which I set to 70%.

I additionally formulate constraints for each country or node to produce on average at least a given share of their annual consumption; i.e. I explore the sensitivity of increasing distributional equity requirements. The extreme cases are (i) every country or node produces as much as required for the purely cost-optimal system using the most productive locations (0%) and (ii) every country or node produces as much as they consume (100%). The experiments interpolate between the extremes in steps of 10%.

I further extend this setup by two experiments regarding absolute autarky: (i) one where there is no cross-border transmission of power between countries but which includes the international transmission grid, and (ii) one where each node fully supplies its own power demand at any time in isolation. The code and assumptions to reproduce all results is available at https://github.com/fneum/equity-and-autarky.

As the results may be very sensitive to technology cost projections, I repeat the analysis for ten uniformly sampled parameter sets obtained from the annuity ranges presented in Table 1 using a low-discrepancy Halton sequence. Due to computational constraints, for this sensitivity analysis I changed from a two-hourly to a three-hourly temporal resolution, while retaining the high spatial detail.

3. Results and Discussion

The discussion of results employs system costs, the technology mix, as well as the distribution of power system infrastructure capacity expansion as evaluation criteria, both regarding distributional equity and autarky considerations. Unless noted otherwise, results are

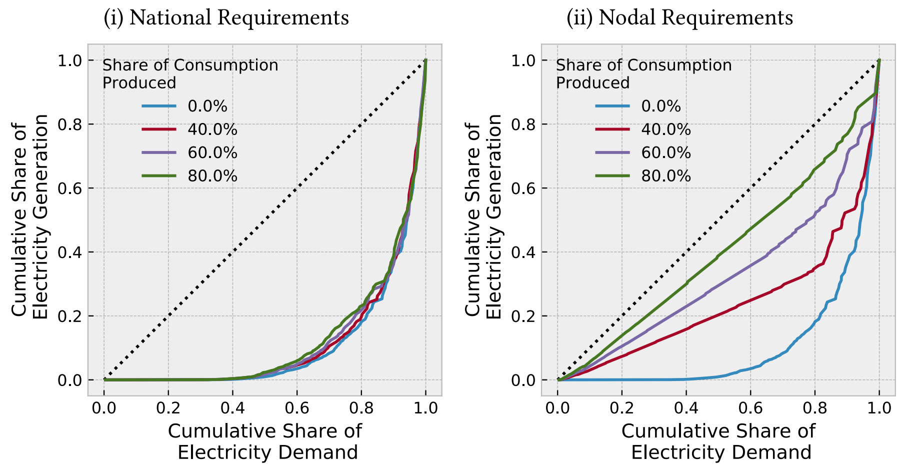

Fig. 4. Lorenz curves for different equity requirements relating the cumulative share of electricity generation to the cumulative share of demand in the 200 regions of the European power system model.

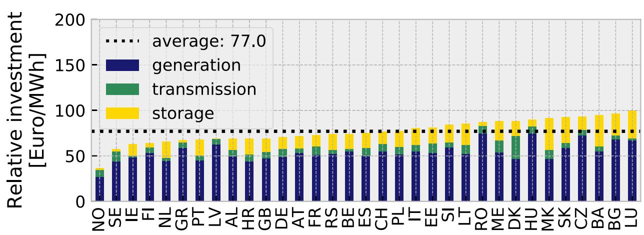

Fig. 5. National annual investment relative to annual demand when every country produces as much as they consume (100%) in reference cost scenario.

presented for the reference technology cost projection labelled in Table 1.

Foremost, Fig. 2 displays the sensitivity of system costs towards nodal and country-wide equity requirements. Similar graphics were produced regarding the amount of cross-border transmission capacities by Schlachtberger et al. [19]. National equity constraints cause a limited rise in the total system cost. The cost increase by less than 4% when every country produces as much as they consume; and by less than 2% when each produces at least 80%. They entail less grid reinforcement and some more solar installations. Conversely, the cost sensitivity is considerably higher for nodal equity constraints. When every node on average produces all they consume, costs inflate by 18%; and already at equity levels of 50% costs increase by 5%. Note that the sensitivity is nonlinear. Nodal requirements shift expansion plans towards onshore wind, solar and hydrogen storage, while reducing network expansion and offshore wind capacities. This confirms but also extends on a finding by Sasse et al. [3]: indeed solar contributes to regional equity, but also onshore wind does. This is ambivalent since onshore wind is susceptible to local opposition.

The maps of the optimised system capacities in Fig. 3 show less but still substantial amounts of transmission expansion in the case of nodal equity. Compared to the unrestricted least-cost solution, the deployment of solar panels progresses northbound and onshore wind capacities spread in Northern and Eastern Europe. Moreover, the storage infrastructure distributes more evenly.

Fig. 4 depicts Lorenz curves as equity measures for different equity constraints (cf. [3]). Like a load duration curve describes the share of time a particular level of electricity demand is exceeded, the Lorenz curve outlines the share of the model's 200 regions where the ratio between total electricity generation and consumption exceeds a certain value. The Lorenz curve is on the identity line if annual sums of generation and load are equal at each node. While nodal equity requirements by definition lift the Lorenz curve, national requirements maintain an unequal distribution of infrastructure within each country.

Results further show that, when every country balances generation and load on average, the national cost for capacity expansion relative to demand is more evenly distributed, ranging between 40 and 100 €/MWh (Fig. 5). Generation infrastructure is the dominant component, followed by storage and transmission. Following conclusions from Li et al. [9], the shared burden of infrastructure buildout can be considered favourable for balanced regional economic development.

While even nodal production equity raises costs only to a limited extent below 20% regardless of how the technology costs will unfold, absolute autarky is robustly much more costly already on a national level. Fig. 6 shows that given the uncertainty of cost inputs eliminating cross-border transmission capacities (i.e. no trade of power between countries) adds costs between 33% and 45%. Costs rise even more when each of the 200 regions is fully self-sufficient, while the level of uncertainty widens. With a cost penalty between 82% and 110%, costs roughly double compared to the minimising costs without equity requirements. Roughly, these numbers align with the cost penalties found by Tröndle et al. [24] in similar recent research. A notable difference could be observed for completely regionally autarkic solutions, for which a lower cost penalty of 69% was obtained despite the higher spatial resolution of almost 500 regions. One possible explanation may be that Tröndle et al. [24] planned the grid from scratch, whereas in the present paper the existing transmission infrastructure was considered.

Fig. 6 further shows that autarkic solutions compensate for the lack of power transmission options with extended deployment of hydrogen and also battery storage alongside additional onshore wind and solar capacities at locations with lower annual yields. Moreover, particularly for the nodal autarky scenario the question arises, whether there is sufficient renewable energy potential to cover demand. However, at least for the considered level of spatial aggregation, this concern can be dismissed as no region uses more than 3% of its area for solar panels and only one in ten regions uses more than 1%, but may become more critical if even smaller regions were modelled [17]. It further needs to be noted that hydrogen storage in salt caverns, as the cheaper alternative to steel tanks if the geological conditions admit it, was neglected.

4. Critical Appraisal and Limitations

In the present evaluation, I focus on the cost perspective and do not assess whether these solutions would actually lead to higher social acceptance or whether they are preferable for other reasons besides costs. The disregard of pathway optimization, reserves, system inertia,

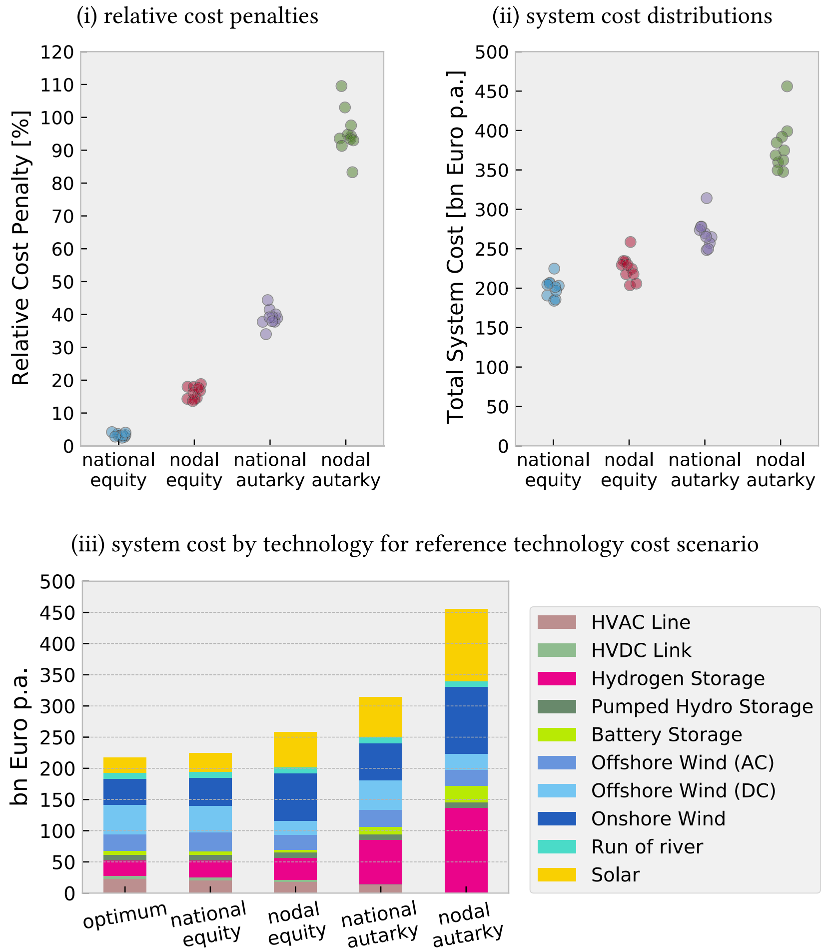

Fig. 6. Total system cost impact of autarky on national and nodal levels compared to the least-cost solution and maximal equity constraints subject to the technology cost uncertainty from Table 1.

adequacy to interannual weather variability, nuclear and biomass resources, as well as import options from North Africa or the Middle East are some of the predominant limitations of the model, whereas its major strengths for the research questions at hand lie in the high spatio-temporal resolution of renewable resources and the transmission network. In future work, the autarky analysis should be expanded to a fully sector-coupled energy system which includes transport options for chemical energy carriers and opens the field to further flexibilities to locally balance supply and demand.

5. Conclusion

It appears to be possible to strike a balance between cost-efficiency and balanced distribution of infrastructure at little additional expense. The analysis showed that aligning annual generation and consumption per country costs less than 4% more; per node, the costs increase by no more than 20%. National balancing, however, retains inhomogenous distributions within the countries, and even when each node produces as much as they consume, power is still extensively transmitted and regions are not self-sufficient. True autarky solutions without power transmission are substantially more expensive, nationally and even more so regionally, such that integrated power systems across regions and countries appear to remain vital component of low-cost future European power system designs. Knowledge about the observed degrees of freedom and boundaries is important, considering that more even investment per region could lead to better political feasibility, quicker implementation, and higher social acceptance.

CrediT author statement

Fabian Neumann: Conceptualization, Methodology, Software, Validation, Formal analysis, Investigation, Data Curation, Writing – Original Draft, Writing – Review & Editing, Visualization.

Declaration of competing interest

The author declares that he has no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

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Appendix A. Supplementary Material

Table A.2
Detailed techno-economic assumptions based on the technology database of the Danish Energy Agency [28] supplementary to annuity-based aggregate Table 1.

	fixed O&M	efficiency	lifetime	investment	investment	
	[%/year]	[%]	[years]	low	high	unit
solar PV utility-scale	2	-	25	250	350	€/kW
solar PV rooftop	1.55	-	25	590	870	€/kW
onshore wind turbine	1.18	-	30	800	1190	€/kW
offshore wind turbine	2.29	-	30	1420	1950	€/kW
run-of-river	2	90	80	3312	3312	€/kW
pumped-hydro storage	1	75	80	2208	2208	€/kW
hydro reservoir	1	90	80	2208	2208	€/kW
fuel cell	5	50	20	500	900	€/kW
electrolysis	5	67	25	200	800	€/kW
hydrogen cavern storage	-	-	100	1	1.8	€/kWh
battery inverter	0.9	96	20	40	250	€/kW
battery storage	-	-	20	46	176	€/kWh
HVAC underground	-	-	25	1342	1342	€/MWkm
HVAC subsea	-	-	25	2685	2685	€/MWkm
HVAC overhead	2	-	40	400	400	€/MWkm
HVAC converter	-	-	25	250	250	€/kW
HVDC underground	-	-	25	1000	1000	€/MWkm
HVDC subsea	-	-	25	2000	2000	€/MWkm
HVDC overhead	2	-	40	400	400	€/MWkm
HVDC converter	-	-	25	400	400	€/kW

Appendix B. Supplementary data

Supplementary data to this article can be found online at https://doi.org/10.1016/j.esr.2021.100652.

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