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Reliability standards and generation adequacy assessments for interconnected electricity systems[☆]

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ABSTRACT

This paper studies the consistency between two contradictory policies in the electricity industry. On the one hand, electricity systems are increasingly interconnected. On the other hand, reliability standards, whose value was typically set when countries were hardly interconnected, are still enforced at the national level. We show that enforcing autarky reliability standards may still reach the welfare optimum in the presence of interconnections, but only under two conditions. First, installed generation capacities should be determined jointly, while considering the whole power system. Second, reliability calculations should fully internalize external adequacy benefits occurring in neighboring systems. We run a numerical application for a set of European countries and find that existing interconnections may lead to generation adequacy benefits of around one billion euros per year, by enabling a 18.9 GW decrease in generation capacity. In our case study, regional coordination is found to be more important than fully internalizing external reliability benefits in adequacy simulations.

1. Introduction

Because electricity supply interruptions have a high economic, social, and political cost, most power system operators are required to run generation adequacy assessments to check if the existing generation fleet is likely to provide the desired level of supply reliability in the short run, and to assess whether additional power plants are needed in the medium and long run. In the latter case, adequacy assessments usually determine how much electricity generation capacity should be installed to meet a given reliability standard set by policymakers. Even in places where wholesale electricity markets have been liberalized, reliability standards are often used to parametrize capacity remuneration mechanisms (Newbery and Grubb, 2015), and to build prospective scenarios for the power system that are subsequently used in many public policy analyses (ENTSOE, 2018).

Most reliability standards are expressed as the expected number of hours per year during which available generation capacity will not be sufficient to meet demand. The value of these loss of load expectation (LOLE) targets ranges from 2.4 h per year (most U.S. systems), 3 h per year (Belgium, France, Great Britain, Italy, Poland), 4 h per year (Netherlands, Germany), to 8 h per year (Ireland, Portugal) (ACER/CEER, 2020). In most cases, these values have not been updated in decades. They were thus derived at a time were interconnection capacity with neighbor power systems was absent or negligible.

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Electricity systems are however becoming increasingly interconnected[1] and decision-makers have realized that cooperation with neighboring systems might provide large generation adequacy benefits.[2] By helping neighbors at times of power scarcity, cooperating countries can indeed avoid some investments in peak generation capacity. Despite this fundamental change in the structure of power systems, generation adequacy assessments are still largely performed on a national basis, with each country making exogenous assumptions – based on either a unilateral or a partially coordinated analysis – about the ability of neighboring countries to export energy during scarcity events.

This paper studies how generation adequacy assessments should be run in interconnected power systems to remain grounded in sound economic theory. Two questions are of particular interest. First, should pre-existing national autarky reliability standards be updated and, if so, how? Second, how critical is it that interconnected power systems coordinate their generation adequacy assessments?

Answering these questions is useful for policymakers and national regulatory authorities (NRAs), as well as for Transmission System Operators (TSOs) and electricity market participants. It is particularly relevant in the context of European energy policy, as a regional adequacy assessment, run by the European Network of Transmission System Operators and based on inputs from national TSOs, has to be implemented by the end of 2023 (ACER, 2020 *b*). This single assessment will determine the need for generation capacity investments in the different countries simultaneously, based on national LOLE targets provided by Member States.[3] More generally, the recent power outages in California (August 2020) and Texas (February 2021) have highlighted the critical role of the availability of respectively neighbors' generation and interconnection capacities.

Somewhat counter-intuitively, we find that enforcing national autarky reliability standards does not necessarily prevent reaching the welfare optimum. To reach the first-best outcome, it is however necessary that national LOLE calculations consider all lost load that can be avoided throughout the entire interconnected system thanks to additional capacity, instead of focusing only on domestic lost load. In other words, a country's LOLE calculations should fully internalize the generation adequacy benefits occurring in other parts of the interconnected system. As a result, at the optimum, realized national LOLE levels will be lower than the national autarky reliability standard. To date, neither current industry practices nor the first draft of the planned European adequacy assessment (ACER, 2020 *b*) seem to compute national LOLE levels in that manner when running generation adequacy assessments.

We also demonstrate the need for regional coordination even when generation adequacy assessments take into account the adequacy contribution of neighbors. Indeed, if the assumed contribution of neighbors in a national adequacy assessment differs significantly from realized levels, we show in an empirical application to European countries that welfare can decrease considerably, even relative to the outcome reached when national adequacy assessments neglect the presence of interconnections. By contrast, regional cooperation and coordination, as proposed by the European resource adequacy assessment methodology (ACER, 2020 *b*), can lead to significant welfare gains relative to the same benchmark.

A number of papers have studied the effect of interconnectors on generation adequacy. Many of them study the interaction between capacity remuneration mechanisms in a two-country setting, focusing on specific market failures, types of capacity adequacy mechanisms and possible asymmetries in implementation. Cepeda and Finon (2011) and Cepeda (2018) use a system dynamics model to build the counterfactual long-term evolution of the interconnected power system under different assumptions. Lambin and Léautier (2019) study a two-stage game where, generators first invest to build capacity (given the capacity remuneration mechanism implemented in each country, if any) and then demand realizes and markets clear. In contrast, our paper studies the *ex ante* stage when generation adequacy simulations are run to assess whether additional capacity should be procured. We thus seek to derive normative results about how generation adequacy assessments should be run, and remain agnostic about which (set of) mechanisms are used in practice to reach the optimal outcome. In addition, our results are valid for an arbitrary number of countries rather than only two countries.

Closer to our work, Cepeda et al. (2009) run simulations for a two-country case study and highlight the importance of regional coordination. Hagspiel et al. (2018) generalizes their study to more than two countries and calculate in a simulation model the minimal generation capacity needed to meet exogenously given country-specific LOLE targets, in line with the European resource adequacy assessment methodology (ACER, 2020 *b*). By contrast, our work does not take LOLE targets as given but simultaneously determines the optimal installed capacities and the LOLE levels, taking into account the fact that countries are interconnected. In other words, our aim is to properly define how national or regional adequacy assessments should be run for interconnected power systems, including how reliability standards should be set and enforced.

Because this paper focuses on the theoretical foundation for the use of reliability standards in an interconnected power system, we do not account for the full set of relevant considerations when assessing LOLE levels. These details are however important in practice to make sure that the simulated scenarios closely match actual system conditions. In particular, there is a growing literature on analyzing the contribution of operating reserves (Hermans et al., 2018), storage (Mertens et al., 2021), and variable renewables to improving system reliability (Bothwell and Hobbs, 2017; Tomasson and Söder, 2017; Peter and Wagner, 2021). In addition, in order to narrow focus on the main economic intuitions, we only crudely account for uncertainty about load and renewable generation (Hagspiel et al., 2018), and disregard generation outages (Cepeda et al., 2009).

The rest of the paper is organized as follows. Section 2 recalls the rationale behind the use of a reliability standard in the autarky case. Section 3 extends this framework to the case of interconnected power systems. In particular, we show the importance of both regional coordination and internalizing external adequacy benefits. Section 4 illustrates our theoretical findings by computing the magnitude of potential gains and losses – relative to installing autarkic capacities – of national, regional, and optimal adequacy assessments, using publicly available data from 11 European countries. Section 5 concludes.

2. Optimal reliability standard in the autarky case

We first consider a single country and derive the well-known expression for the optimal reliability standard in autarky. Our framework makes a number of simplifying assumptions, which are commonly used in this setting (see for example Chao (1983) or Léautier (2016)).

First, we assume that the residual demand (i.e. gross load minus output from intermittent zero-marginal-cost renewables) for electricity

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[1] For example in Europe, all but three member states have met the 2020 target to have a level of electricity interconnections of at least 10% of installed generation capacity (Official Journal of the European Union, 2013; European Commission, 2017). In the United States, massive investments in regional interconnections are envisioned to support the proposed decarbonization of the electricity sector by 2035. Similarly, China's Global Energy Interconnection initiative aims at drastically increasing interconnection capacity between grid regions in China and envisions a worldwide energy grid that transmits clean energy across continents (Downie, 2020).

[2] Interconnection also leads to other benefits, such as fuel cost savings (Newbery et al., 2016), decreasing market power (Ryan, 2021; Woerman, 2021), cross-border balancing (Van den Bergh et al., 2017), sharing of reserve capacity (Baldursson et al., 2018), and better integration of variable and intermittent renewable generation (Pean et al., 2016).

[3] ACER (2020 *a*) has required all European countries to determine an explicit LOLE target, based on detailed studies of the value of lost load and the cost of new entry, pursuant article 25(2) of Regulation (EU) 2019/943.

D is inelastic. Indeed, most electricity consumers do not face dynamic prices. In addition, our analysis will focus on hours with the highest net demand levels, that is hours during which no renewable zero-marginal-cost generation is curtailed. We denote $f(D)$ the probability density function of hourly residual demand levels $D \in [\underline{D}, +\infty[$ over the course of a given year. We denote $F(D) \equiv \int_{\underline{D}}^{D} f(x)dx$ the corresponding cumulative distribution function. In other words, the probability that hourly net load exceeds a given level D over the course of a given year is $1 - F(D)$.

Second, we focus on a static situation where $f(.)$ is not assumed to change over time. In this setting, $f(.)$ captures periodic patterns in gross consumption, as well as idiosyncratic shocks in demand and renewable generation, for example depending on weather realizations. This assumption is reasonable in the context of generation adequacy assessments, which are most often run in order to assess system reliability for the upcoming few years.

Third, we model a single dispatchable generation technology, namely the one with the highest short-term marginal cost used to match demand in times of scarcity. Indeed, a more detailed model accounting for all inframarginal technologies (e.g. coal, combined-cycle gas turbine, nuclear, etc.) would yield different total generation costs, but identical marginal expressions for optimal reliability. We envision this single technology to be a peaking thermal plant like a gas turbine, although demand response might replace it in the future. It is characterized by an annualized long-term marginal capacity cost γ and a short-term marginal cost c. The (annualized) investment cost to get a capacity K MW is γK, and the variable cost of producing D MWh of electricity is cD as long as $D \leq K$. For simplicity, we neglect plant outages.

During extreme events when demand D is larger than installed capacity K, we assume that $D - K$ is curtailed at a marginal cost V, called the value of lost load (VoLL) V (in EUR/MWh) – without causing a system-wide blackout. In the case of random rationing, the VoLL is equal to the average willingness-to-pay for power of curtailed consumers. But as the cost of curtailment depends on the time, location, and consumer group (Ovaere et al., 2019), the single VoLL might more generally represent the most likely EUR/MWh cost of supply interruptions in terms of time, location, and interrupted consumer (ACER, 2020*a*, article 7).[4]

In this simple framework, ensuring capacity adequacy boils down to optimizing the level of installed generation capacity. Under the assumptions above, the same optimal capacity is obtained when considering either welfare maximization or system costs' minimization. We will thus use a cost-minimization approach for simplicity in what follows. The cost-minimization problem with respect to the installed generation capacity K is:

$$\min_K \gamma K + \int_{\underline{D}}^{+\infty} c \cdot \min(D, K) f(D) dD + \int_{K}^{+\infty} V \cdot (D - K) f(D) dD \tag{1}$$

That is, total cost consists of the cost of investing in generation capacity, the cost of using that capacity, and the cost of interruptions in case of load curtailment. The optimal installed capacity K^* is then defined by the following first-order condition (Chao, 1983):[5]

$$(V - c)\Pr[D > K^*] = \gamma \tag{2}$$

This expression is very intuitive: generation capacity should be installed up to the point where the marginal cost of generation investment (right-hand side) equals the marginal avoided cost of interruptions (left-hand side) (Boiteux, 1949; Steiner, 1957; Turvey, 1968). The left-hand side might be interpreted as the net VoLL multiplied by the expected frequency of lost load events. This probability is generally referred to as the loss of load probability (LOLP). It takes value between 0 and 1 and is expressed as a percentage. However, the typical units used in the industry to measure γ (in/MW/year) and V (in/MWh), often makes it more convenient to use instead the loss of load expectation (LOLE), which is the same metric expressed in number of hours per year (that is $LOLE \equiv 8760 \times LOLP$) (European Parliament and Council of the European Union, 2019, article 25(3)). Rearranging equation (2) then leads to the following proposition.

Proposition 1. (***Optimal reliability standard in the autarky case***) *The first-order optimality condition may be implemented by enforcing a reliability standard:*

$$LOLE = \frac{\gamma}{V - c} \equiv \alpha \tag{3}$$

In words, this equation may be interpreted as "installed capacity should be such that the expected number of hours per year during which some energy is not served is equal to α*." The expected number of hours per year where some load must be curtailed is called the "loss of load expectation" (LOLE). The LOLE target* α *is known as the autarky reliability standard, defined as the ratio of the long-term marginal capacity cost (in €/MW/year) and the net VoLL (in €/MWh) .*

Typical orders of magnitude that have been considered in Europe for the value of the parameters are $\gamma \simeq 60$ k€/MW/year and $V \simeq 20$ k€/MWh (c is neglected relative to V). This back-of-the-envelope calculation hence yields an autarky reliability standard of $\alpha = 3$ h per year.

Proposition 1 determines the optimal installed capacity, but is agnostic about how this capacity will be realized. Under the assumptions of the first welfare theorem (e.g. perfect competition, perfect information, or rationality), decentralized market participants will together install the optimal generation capacity. In reality, however, the capacity actually installed may diverge from the optimal capacity, because there are market failures, such as market power, strategic interactions (Bucksteeg et al., 2019; Lambin and Léautier, 2019; Roques, 2019; Zimmermann et al., 2021), price caps, or heterogeneous national capacity mechanisms (Astier and Lambin, 2019; Fabra, 2018; Hickey et al., 2021; Holmberg and Ritz, 2020; Joskow and Tirole, 2007; Léautier, 2016). In what follows, we focus on the conditions for optimality and leave the actual implementation of these optimal capacities for future research.

3. National reliability standards and adequacy assessments for interconnected power systems

3.1. Framework and notations

We now extend the previous framework to the case of interconnected power systems. As in the autarky case, countries or regions must decide how much generation capacity to install. However, they now have to take into account the fact that interconnectors can help to reach the desired level of electricity supply reliability. In order to simplify notations and highlight economic intuitions, we first focus on the two-country case and postpone the discussion of the general case to paragraph 3.7.2. We assume both countries have the same VoLL V. We discuss in paragraph 3.7.1 how our results extend to asymmetric VoLLs, which may stem from heterogeneous opportunity costs to curtail load and/or different welfare weights put on curtailed customers.

Let D_i with $i \in \{1, 2\}$ be the hourly net demand level in country i, whose installed capacity is K_i. The vector (D_1, D_2) is distributed according to a density f on $[\underline{D}_1, +\infty[\times [\underline{D}_2, +\infty[$. Both countries are interconnected, with (exogenous) cross-border capacities L_{12} and L_{21}, where L_{ij} is the available transmission capacity from country i to country j. Consistently with the Net Transfer Capacities (NTC) models currently in

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[4] Several methods exist for estimating the VoLL, like stated-preference (contingent valuation, choice experiments, direct worth surveys), revealed-preference (case studies or market behavior analysis), and production function approaches. Each of these methods has its advantages and disadvantages (CEPA, 2018). In Europe, sectoral and national VoLLs should be estimated using dedicated (direct worth) stated-preference surveys (ACER, 2020 *a*).

[5] The second-order condition for minimum is easily shown to be satisfied.

use in most of Europe,[6] national power networks, Kirchhoff voltage law and power losses are neglected in our simplified framework.[7]

3.2. Country-specific LOLE levels are no longer unambiguously defined

To fix ideas, let's assume for now that the installed capacities (K_1, K_2) are exogenously given. Load may then have to be curtailed for two different reasons. First, total installed capacity may be insufficient to serve total demand. This happens during hours where $D_1 + D_2 > K_1 + K_2$. Second, a single country may have a domestic capacity shortage, and available import capacity may not be high enough to close the gap. For example, such a situation would arise for country 1 when $D_1 > K_1 + L_{21}$. The gray shaded area in Fig. 1 highlights the demand realizations (D_1, D_2) for which some load must be curtailed, given interconnector capacities L_{12} and L_{21} and installed capacities K_1 and K_2.

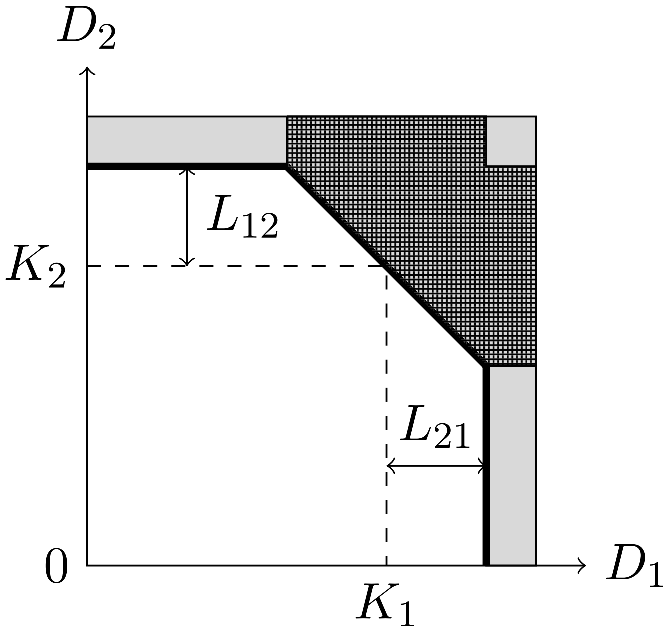

Fig. 1. Lost-load region (gray shaded area) for given installed generation capacities (K_1, K_2) and interconnection capacities (L_{12}, L_{21}). For demand realizations in the hatched area, it is ambiguous whether load will be curtailed in a single country or in both.

Importantly, and by contrast to the autarky case, the LOLE metric is no longer unambiguously defined for each country taken in isolation.[8] For demand realizations in the hatched area of Figs. 1,[9] load needs to be curtailed but curtailments may happen either in a single country or in both. Indeed, if $K_1 - L_{12} < D_1 < K_1 + L_{21}$, country 1 may or may not experience lost load depending on how the interconnector is operated. Symmetrically, if $K_2 - L_{21} < D_2 < K_2 + L_{12}$ whether or not country 2 has to curtail load is ambiguous.

Given installed generation and interconnection capacities, Fig. 2 shows in gray the LOLE region for country 1, depending on which country is curtailed first when available generation is not sufficient.[10] We display three possible load curtailment priority rules (from the perspective of country 1):

- **Neighbor altruism:** country 1 may assume that imports from country 2 are always available as long as the import capacity is not constrained, even when country 2 is itself experiencing a capacity shortage;
- **Domestic priority:** country 1 may assume that country 2 will first use its generation capacity to serve its domestic demand, only offering to export electricity from its excess capacity;
- **Own altruism:** country 1 may prioritize exports to country 2, even when this choice makes it necessary to curtail domestic load.

Assuming neighbor altruism (left panel on Fig. 1), country 1 only expects loss of load when $D_1 > K_1 + L_{21}$, because imports from country 2 are expected to be available at all times. By contrast, expected loss of load for country 1 is higher when assuming own altruism (right panel on Fig. 1), because country 1 is willing to curtail its own load to prioritize exports to country 2.

3.3. Installed capacities prescribed by generation adequacy assessments depend on the assumed load curtailment priority rule

A *generation adequacy assessment* is a simulation exercise where country-specific LOLE levels are computed. This exercise generally aims at making sure that each country meets its *reliability standard*. This reliability standard is expressed as $\widehat{LOLE}_i \equiv \widehat{\alpha}$, where $\widehat{LOLE}_i$ is the LOLE level computed for country i during the generation adequacy assessment and $\widehat{\alpha}$ is the reliability standard.

As discussed above, the LOLE level $\widehat{LOLE}_1$ obtained for country 1 in the context of a generation adequacy assessment will depend on (i) how much capacity is installed in country 2; and (ii) load curtailment priorities in times of scarcity. This paragraph focuses on the latter point, and the next paragraph discusses the former.

Fig. 3 illustrates how the installed capacity for country 1 prescribed by a reliability standard $\widehat{\alpha}$ depends on the assumed load curtailment priority rule. Taking the installed capacity K_2 in country 2 as given, it shows the installed generation capacity that would be prescribed by a generation adequacy assessment for country 1 under respectively the neighbor altruism, the domestic priority, and the own altruism priority

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[6] The European Commission, NRAs, TSOs, consulting firms, etc. typically rely on such models for decision-making purposes. This approach is for example the one used in Europe within the Ten-Year Network Development Plan (TYNDP). Moving from an NTC to a flow-based model is actually one of the five main challenges identified by ENTSO-E itself for the future of adequacy assessments (https://www.entsoe.eu/outlooks/eraa/). It thus lies beyond the scope of this paper.

[7] While this assumption was reasonable in the case of vertically integrated utility that chose both power plant locations and transmission grid upgrades, this may prove a strong assumption when reliability standards are used in the context of interconnected countries, especially when assessing the value of new interconnectors. Indeed, the security of supply benefits of a new transmission line are likely to significantly depend on its location on the network, and the ability of the network to inject/consume additional power at the nodes to which the new power line connects (Ovaere and Proost, 2018).

[8] As we discuss in paragraph 3.6, realized LOLE levels are however likely to be unambiguous in practice if each country prioritizes its own load. Beyond political considerations, assuming non-zero power losses for the interconnector would also argue for prioritizing domestic load. Paragraph 3.7.1 illustrates how our results generalize in an intuitive way when the methodology to compute country-specific LOLE is exogenously given.

[9] Mastropietro et al. (2015) note that the operational rules followed in practice by TSOs during such states of the world can have a large influence on the incentives provided by national capacity remuneration mechanisms for interconnected countries.

[10] Note that the LOLE is not directly proportional to the size of the gray shaded area, but is equal to the probability (expressed in number of hours per year) that a given realization (D_1, D_2) of net demand levels falls into this area.

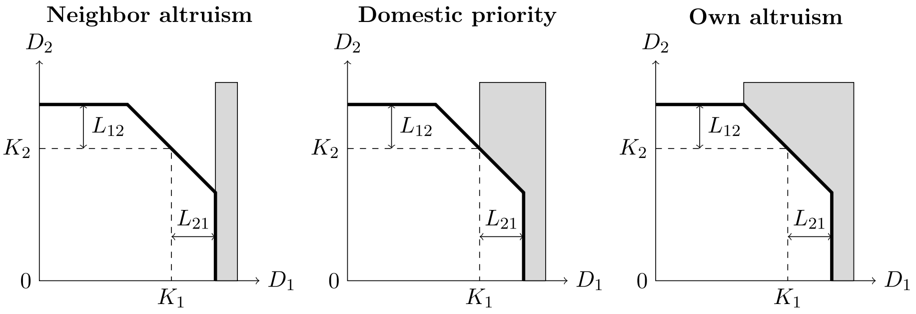

Fig. 2. LOLE region of country 1 (gray shaded area) depending on the load curtailment priority rule assumed and for given installed generation capacities (K_1, K_2) and interconnection capacities (L_{12}, L_{21}). The LOLE itself is not directly proportional to the size of the LOLE region, but is equal to the probability (expressed in number of hours per year) that a given realization (D_1, D_2) of net demand levels falls into this area.

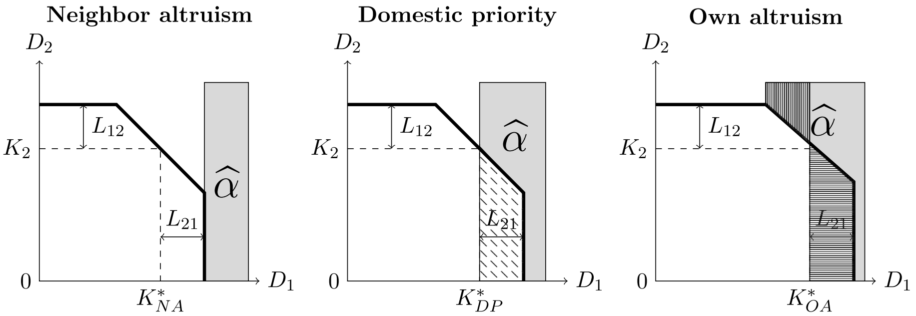

Fig. 3. Installed capacity in country 1 depends on the load curtailment priority rule used in its generation adequacy assessment, given installed capacity K_2: $K^*_{1,NA} \leq K^*_{1,DP} \leq K^*_{1,OA}$.

rule. It is clear that installed capacity increases the more a country prioritizes serving load in the neighboring country.

Fig. 3 also shows that installed capacity under the domestic priority rule is always lower than in autarky if there are benefits from interconnection, i.e. if there are load realizations in the diagonally hatched area. Country 1 can then install less generation capacity because it is able to get some power in times of scarcity from country 2 through the interconnection.

For the case of the own altruism rule, installed capacity is lower than the autarky capacity $K^*_{autarky}$ as long as the probability of load realizations in the horizontally hatched area is larger than the probability of load realizations in the vertically hatched area. In summary:

$$K^*_{1,NA}(K_2) \leq K^*_{1,DP}(K_2) \leq \min\Big(K^*_{1,OA}(K_2), K^*_{1,autarky}(K_2)\Big) \tag{4}$$

3.4. National vs regional adequacy assessments

Beyond the assumed load curtailment priority rule, the LOLE region for country 1 depends on the installed capacity K_2 in the neighbor country. In what follows, we will distinguish two cases.

First, we will call *national adequacy assessments* the situation where $\widehat{LOLE}_1$ (resp. $\widehat{LOLE}_2$) is computed while making an exogenous assumption regarding installed capacity K_2 (resp. K_1) in the neighbor country. In other words, country 1 makes an explicit assumption about the installed capacity K_2 and solves for its “adequate” installed capacity $K_1^\dagger$ defined as $\widehat{LOLE}_1(K_1^\dagger, K_2) \equiv \widehat{\alpha}$. Similarly, country 2 makes an explicit assumption about the installed capacity K_1 (which may differ from $K_1^\dagger(K_2)$) and solves for its “adequate” installed capacity $K_2^\dagger$ defined as $\widehat{LOLE}_2(K_1, K_2^\dagger) \equiv \widehat{\alpha}$. As previously discussed, computing $\widehat{LOLE}_i$ itself supposes to make an assumption regarding load curtailment priority rules. The “national adequacy assessments” case would correspond to a situation where each country runs its own adequacy assessment in isolation, without necessarily coordinating with its neighbors.

Second, we will call *regional adequacy assessment* the situation where ($\widehat{LOLE}_1$, $\widehat{LOLE}_2$), and thus (K_1, K_2), are computed simultaneously. In other words, the adequacy assessment consists in solving jointly for $(K_1^\dagger, K_2^\dagger)$ such that $\widehat{LOLE}_1(K_1^\dagger,\ K_2^\dagger) = \widehat{LOLE}_2(K_1^\dagger,\ K_2^\dagger) \equiv \widehat{\alpha}$. Again, computing $\widehat{LOLE}_i$ requires to specify which country/countries have to curtail load in times of scarcity. The “regional adequacy assessment” case would correspond to a situation where a coordinating entity is in charge of assessing generation adequacy for the interconnected power system.

The outcome of either type of adequacy assessments is a pair of installed capacities $(K_1^\dagger, K_2^\dagger)$ which are deemed necessary to meet the reliability standard $\widehat{\alpha}$ in each country. These installed capacities will take different values depending on (i) whether the adequacy assessment is national or regional, and (ii) which curtailment priority rule is assumed in generation adequacy simulations when computing country-specific LOLE levels.

3.5. Optimal adequacy assessment

In this paragraph, we characterize the cost-minimizing outcome for the power system as a whole. As in the autarky case, the optimal levels of installed capacity are obtained by minimizing the cost of investing in generation capacity, the cost of using that capacity, and the cost of interruptions in case of involuntary load curtailment. However, in this case we are minimizing total costs for both countries. The following proposition characterizes the first-order conditions that define optimal installed capacities when two countries are interconnected:

Proposition 2. **(*Optimal reliability standard in the two-country case*)** *The first-order conditions for cost-minimization are:*

$$\widehat{LOLE}_1 = \widehat{LOLE}_2 = \frac{\gamma}{V-c} \equiv \alpha \tag{5}$$

where

$$\begin{cases} \widehat{LOLE}_1 \equiv \Pr[D_1 > K_1 + L_{21}] + \Pr[\{D_1 + D_2 > K_1 + K_2\} \cap \{K_1 - L_{12} \leq D_1 \leq K_1 + L_{21}\}] \\ \widehat{LOLE}_2 \equiv \Pr[D_2 > K_2 + L_{12}] + \Pr[\{D_1 + D_2 > K_1 + K_2\} \cap \{K_2 - L_{21} \leq D_2 \leq K_2 + L_{12}\}] \end{cases} \tag{6}$$

In other words, each country may keep their autarky reliability standard target $\alpha = \frac{\gamma}{V-c}$ as long as they correctly compute the LOLE levels $\widehat{LOLE}_i$ in their adequacy assessments.

Proof. See Appendix A.

Just as in the autarky case, the first-order conditions stipulate that generation capacity should be installed up to the point where the marginal cost of generation capacity equals the marginal expected avoided cost of interruptions. Conveniently, they can be rewritten for each country i as $\widehat{LOLE}_i = \alpha$, where α is the autarky reliability standard, which is likely to pre-exist for historical reasons. In other words, updating historical reliability standards is not necessarily needed when countries interconnect.

As discussed in Section 3.2, country-specific LOLE levels are ambiguous for interconnected power systems. Proposition 2 hence clarifies how country-specific LOLE levels should be computed in adequacy assessments in order to make sure that enforcing autarky reliability standards still minimizes total system costs. More specifically, equation (6) shows that lost load should be assumed to occur not only when a country has a capacity shortage that cannot be alleviated by imports (first term), but also when the system as a whole is experiencing a capacity shortage and some interconnection capacity is available to export electricity (second term). Importantly, hours where additional domestic capacity could have decreased lost load in the neighbor country should also be counted as lost load hours.

The approach for computing country-specific LOLE levels prescribed by Proposition 2 aligns with economic intuition. Indeed, it states that expanding generation capacity K_1 does not only decrease the expected lost load in country 1, but also the expected lost load in country 2, and that this latter positive externality should be fully taken into account. In other words, *when performing its domestic adequacy assessment, a given country should fully internalize the security of supply benefits that its installed capacity provides to his neighbor.*

Corollary 1 *In the two-country case, the "own altruism" curtailment priority rule must be assumed when performing generation adequacy assessments for the autarky reliability standard to yield the welfare optimum. In addition, the adequacy assessment must be regional unless each country correctly anticipates the equilibrium installed capacity of its neighbor.*

Proof. The regions described by equation (6) correspond to the LOLE region of the own altruism rule on Fig. 2. In addition, the expression for $\widehat{LOLE}_i$ depends on both K_1 and K_2 so that optimal capacities needs to be determined jointly in a regional assessment.

It is important to note that Corollary 1 does not imply that the "own altruism" rule should be enforced in the context of real-life operations. Indeed, it is doubtful that a country that has sufficient domestic capacity will purposely choose to curtail its own load to help a neighboring country meet its electricity demand. However, the Corollary states that, *in the context of adequacy assessment simulations with country-specific reliability standards*, the "own altruism" rule should be assumed when computing the LOLE level of a given country. This approach makes sure that each country fully internalizes the positive effect of its own generation capacity on the security of supply of its neighbor.

3.6. Simulated vs realized LOLE levels

The previous paragraph showed that the optimal installed capacities can be found by solving $\widehat{LOLE}_1 = \widehat{LOLE}_2 = \alpha$, provided $\widehat{LOLE}_i$ is correctly computed. In the two-country case, the correct computation of $\widehat{LOLE}_i$ supposes to use the "own altruism" priority rule when computing the LOLE level of a given country.

In actual operations however, domestic load is likely to be served in priority.[11] For example, European TSOs are required to prioritize meeting their domestic electricity demand before using interconnectors to help neighboring TSOs in emergency situations (European Commission, 2017, article 14(1)). As a result, *realized* LOLE levels will be equal to:

$$\begin{cases} LOLE_1 \equiv \Pr[D_1 > K_1 + L_{21}] + \Pr[\{D_1 + D_2 > K_1 + K_2\} \cap \{K_1 \leq D_1 \leq K_1 + L_{21}\}] \\ LOLE_2 \equiv \Pr[D_2 > K_2 + L_{12}] + \Pr[\{D_1 + D_2 > K_1 + K_2\} \cap \{K_2 \leq D_2 \leq K_2 + L_{12}\}] \end{cases} \tag{7}$$

In other words, realized LOLE levels will differ from the levels $\widehat{LOLE}_i$ computed in the context of generation adequacy assessments.

Corollary 2 *At the optimum, realized LOLE levels will be lower than the LOLE levels computed in the context of adequacy assessment simulations, and thus lower than the reliability standard for the optimal installed capacities. Indeed:*

$$\begin{cases} \widehat{LOLE}_1 \equiv LOLE_1 + \Pr[\{D_1 + D_2 > K_1 + K_2\} \cap \{K_1 - L_{12} \leq D_1 \leq K_1\}] \\ \widehat{LOLE}_2 \equiv LOLE_2 + \Pr[\{D_1 + D_2 > K_1 + K_2\} \cap \{K_2 - L_{21} \leq D_2 \leq K_2\}] \end{cases} \tag{8}$$

which implies:

---

[11] We rule out inappropriate state interventions in electricity crises which may for example artificially limit cross-border flows and/or cross zonal transmission capacities through NTC calculations (European Parliament, 2019).

$$\begin{cases} LOLE_1 \leq \widehat{LOLE}_1 = \alpha \\ LOLE_2 \leq \widehat{LOLE}_2 = \alpha \end{cases} \tag{9}$$

For example, when the long-term marginal capacity cost is 60 k€/MW/year and the value of lost load is 20 k€/MWh, the optimal realized LOLE levels will be weakly lower than 3 h per year.

3.7. Extensions

3.7.1. Generalization to asymmetric VoLLs

We assumed so far that both countries use the same VoLL. In practice this value may differ across countries (CEPA, 2018). For example, the opportunity cost to curtail load may be heterogenous or a social planner may consider using welfare weights for curtailed customers. In this paragraph, we discuss how Proposition 2 generalizes to a situation where the two countries have VoLLs V_1 and V_2, with $V_1 \neq V_2$.

As previously discussed, we assume that each country prioritizes its own load in times of scarcity.[12] We then minimize total long-term costs subject to this curtailment priority rule and get the following Proposition.

Proposition 3. (***Two-country case with asymmetric VoLLs***) *The first-order conditions for cost-minimization are:*

$$\widehat{LOLE}_1 = \frac{\gamma}{V_1 - c} \equiv \alpha_1 \tag{10}$$

$$\widehat{LOLE}_2 = \frac{\gamma}{V_2 - c} \equiv \alpha_2 \tag{11}$$

where

$$\begin{cases} \widehat{LOLE}_1 \equiv LOLE_1 + \frac{V_2 - c}{V_1 - c}\Pr[\{D_1 + D_2 > K_1 + K_2\} \cap \{K_1 - L_{12} \leq D_1 \leq K_1\}] \\ \widehat{LOLE}_2 \equiv LOLE_2 + \frac{V_1 - c}{V_2 - c}\Pr[\{D_1 + D_2 > K_1 + K_2\} \cap \{K_2 - L_{21} \leq D_2 \leq K_2\}] \end{cases} \tag{12}$$

and realized LOLE levels $LOLE_i$ are given by equations (7).

Proof. See Appendix A.

Proposition 3 shows that, in order to keep using their autarky reliability standards α_1 and α_2, countries should make sure to internalize in their LOLE calculations the adequacy benefits occurring in the neighbor country. Indeed, in both equation (12), the second term on the right-hand side corresponds to demand realizations where the considered country does not have to curtail its domestic load (since its installed capacity is sufficient to serve its own load) but could decrease the magnitude of the load curtailments incurred by its neighbor by increasing its installed capacity. Because lost load in the neighbor country is assumed to have a different social value, the lost load hours of the second term should be weighted by the ratio of net VoLLs. Note in particular that when $V_1 = V_2$, equation (12) simplifies to equation (8).

3.7.2. Generalizing to N countries

While generalizing our results to power systems with N countries and complex interconnection patterns requires more cumbersome notations, the intuition behind our previous results remains valid. In other words, both regional coordination and full internalization of external generation adequacy benefits are needed to reach the first-best outcome. Assessing whether a given neighbor country "needs help" in a given hour is however harder to characterize in terms of simple priority rules. Yet, as in the two-country case, it is possible to define a methodology to compute country-specific LOLE levels $\widehat{LOLE}_i$ such that enforcing autarky reliability standards remains consistent with total cost minimization. This result is summarized in the following Proposition.

Proposition 4. (*Optimal reliability standard in the N-country case*) *The first-order conditions for cost-minimization can be written as:*

$$\widehat{LOLE}_1 = \ldots = \widehat{LOLE}_N = \frac{\gamma}{V - c} \equiv \alpha \tag{13}$$

where $\widehat{LOLE}_i$, computed in the adequacy assessment simulations, consists of all hours when marginally increasing installed capacity K_i could reduce the amount of curtailed energy anywhere in the interconnected power system.

Proof. See Appendix B.

Proposition 4 generalizes the economic intuition derived from the two-country case. First, the computation of $\widehat{LOLE}_i$ depends on the installed capacities in all countries, highlighting the need for regional coordination. Second, this computation should not only consider domestic adequacy benefits, but also make sure to internalize adequacy benefits occurring in neighbor countries.

4. Application to Western Europe

This section shows how our theoretical framework may be applied in practice in the context of reliability assessments. In order to focus attention on the main insights from our theoretical analysis, we keep this empirical exercise as simple as possible. Our numerical application is thus primarily illustrative, and abstracts away from important practical aspects of reliability assessments, such as plant and network outages, flow-based market coupling, and the need to account for a very large number of possible realizations for the timeseries of demand, weather and renewable generation.

4.1. Approach

Our numerical application consists in comparing the total annual cost (in M€/year) – defined as the sum of the capital cost of investing in generation capacity and the opportunity cost of curtailed energy – under different scenarios. Scenarios differ according to how national reliability standards are accounted for in generation adequacy assessments, which in turn prescribes how much capacity is assumed to be installed in each country. Actual operations are then assumed to minimize the volume of load curtailments given installed capacities, so that realized LOLE levels need not be equal to the reliability standard. Because we do not model inframarginal generation technologies and neglect short-term generation variable costs, the total cost under a single scenario is not particularly informative. Short-term variable costs would however be roughly the same under all scenarios as long as the peaker technology is always marginal in all countries in times of scarcity, which is a reasonable approximation given the significant correlation between the occurrence of peak demand hours across neighbor countries. As a result, the differences in total costs between two scenarios do correspond to the differences that would be obtained from a more detailed representation of the power system.

As discussed in Section 3, setting a national reliability standard is not a properly-defined policy for an interconnected country. We thus simulate four distinct scenarios to capture different ways in which countries may enforce a domestic reliability standard. These scenarios

Table 1
Characteristics of the different scenarios studied.

	Autarky	National	Regional	Optimal
Interconnections are accounted for		X	X	X
Assumptions are consistent across national assessments			X	X
External adequacy benefits are internalized				X

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[12] By contrast, strict cost-minimization with asymmetric VoLLs would suggest to prioritize meeting demand in the country with the highest VoLL in times of joint scarcity but such a scenario seems unlikely to materialize in practice.

differ along three dimensions (see Table 1). First, each country may just completely ignore interconnections in its domestic generation adequacy assessment, and thus maintain the same level of installed capacity as under autarky (defined by equation (3)). The two other dimensions reflect the key take-aways from Corollary 1 and Proposition 4: policymakers should clarify how the generation adequacy assessment are run, which involves (i) making assumptions about the installed generation capacities in neighbor countries; and (ii) defining a methodology to compute unambiguous domestic LOLE levels in the context of generation adequacy assessments. Under the "national adequacy assessments" scenario, countries do not coordinate to make consistent assumptions about future installed generation capacities. Each country naively assumes that neighboring countries will install their autarkic capacity, and – under this assumption – installs the level of generation capacity that enables it to achieve a *realized* domestic LOLE equal to the reliability standard.[13] By contrast, under the "regional adequacy assessment" scenario, countries coordinate to make consistent assumptions about installed capacities and run a joint optimization accounting for the whole power system. However, they do not internalize external adequacy benefits in the LOLE levels computed during generation adequacy simulation. Instead, they just aim at achieving *realized* LOLE levels equal to the reliability standard. We interpret this scenario as reflecting ACER's initial proposal for implementing a European generation adequacy assessment (ACER, 2020 *b*). Finally, under the "optimal assessment" scenario, countries implement Propositions 2 and 4.

Because national capacities must be determined jointly for the regional and optimal adequacy assessments, we implement a simple iterative algorithm that converges to a fixed point meeting all domestic reliability standards. More precisely, we first initialize installed capacities at the historical maximum net load for each country. Given these installed capacities, we then compute the expected LOLE levels corresponding to the scenario of interest. For the "regional adequacy assessment" scenario, we use *realized* domestic LOLE levels, which are defined below. Under the "optimal assessment" scenario, we use the formula for $\widehat{LOLE}_i$ from Propositions 2 and 4. We finally update the installed capacities in each country based on the difference between their current and targeted LOLE levels. The procedure is iterated until it converges to a fixed point.

In all scenarios, we compute *realized* LOLE levels as follows. First, we identify the hours during which the country of interest should be considered as experiencing a lost-load event in the context of an optimal adequacy assessment. These hours correspond to demand realizations appearing in the formula for $\widehat{LOLE}_i$ from Propositions 2 and 4. For each of these hours, we then check whether the country of interest has sufficient domestic capacity to supply its own demand, which can happen due to external adequacy benefits (i.e. situations where increasing capacity in one country that has sufficient capacity could nonetheless alleviate load curtailments in a neighbor country). All such hours are no longer considered as lost load hours for the country of interest.

We implement our approach for a set of 11 European countries,[14] assuming a reliability standard of $\alpha = 3$ h per year. Beyond total costs, we report the total installed capacity and realized LOLE level (averaged across countries).[15] We first consider each of the 15 directly-interconnected country pairs taken in isolation. In other words, we consider each country pair as a separate power system composed of only two countries and ignore other interconnectors. We then run a numerical application for the complete interconnected power system.

Table 2

Summary statistics of net hourly load [MW] in the 11 studied countries.

Country	Mean	P95	$K^*_{autarky}$	Maximum
Belgium	8826	11,391	13,173	13,464
Denmark	2061	4075	5265	5584
France	50,019	71,582	88,837	90,723
Germany-Austria-Luxembourg	46,875	68,304	82,137	84,104
Great Britain	29,921	42,852	54,437	57,362
Ireland	2322	3593	4555	4846
Italy	29,086	41,065	48,101	49,336
Netherlands	12,329	15,963	18,046	18,468
Portugal	4184	6271	8180	8444
Spain	21,674	29,832	36,078	37,451
Switzerland	6697	8324	9662	10,893

Note: Germany load is aggregated with Austria and Luxembourg. When real-time consumption was missing, day-ahead forecast was used instead. Outlier observations for which day-ahead forecast and real-time realization differed by more than 30% were replaced by median values.

4.2. Data

Our data are compiled from the ENTSOE-Transparency platform (ENTSO-E, 2019) and cover January 2016 to December 2019. For 11 European countries (or group of countries), we retrieve hourly gross load, hourly generation from wind and solar and net transfer capacity (NTC) at each border. We compute net hourly demand levels by substracting the hourly generation from wind and solar from the hourly gross load. It is worth noting that actual generation adequacy assessments typically model hundreds of possible net hourly demand realizations for the year, accounting for example for multiple possible weather outcomes. The corresponding hourly net demand levels are however not available for the 11 (group of) countries we consider. As a result, our numerical application only relies on four years of realized hourly net demand levels, and thus mostly serves an illustrative purpose.

Table 2 provides summary statistics for the timeseries of hourly net load. Mean hourly net consumption ranges from 2.3 GWh for Ireland to 50 GWh for France. Table 2 also shows the installed capacity that would be optimal under autarky, as defined in Proposition 1.

Table 3 provides the matrix of median NTCs for each border where an interconnection exists. Because they do not correspond to physical characteristics of the interconnectors but instead derive from *ad hoc* calculations that try to account for the fact that day-head markets ignore physical network constraints, NTC values fluctuate over time and often depend on the direction of power flows.[16] The eleven countries we consider are linked through 15 interconnections, thus representing a fairly complex power system.

4.3. Results and discussion

Table 4 shows the obtained results for the 15 country pairs taken in isolation. Total costs are the sum of annualized investment costs (assuming a cost of 60 k€/MW/year), which are obtained from our four scenarios for adequacy assessment methodologies, and of the opportunity cost of unserved energy (assuming a value of lost load at 20 k€/MWh), where the calculation of the volume of unserved energy account

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[13] For simplicity, we assume that domestic generation adequacy assessments only take into account direct neighbors (whose interconnections with other countries are neglected).

[14] The load from Germany, Austria and Luxembourg is aggregated.

[15] Given the discrete nature of the input data and the assumption of lossless interconnectors, country-level outcomes are not unique. Although obtained country-level capacities can differ significantly depending on the seed values are used, the aggregate metrics we report are fairly stable. In particular, total cost is unique for the optimal adequacy assessment scenario.

[16] In practice, only the DC interconnections with Great Britain have symmetric NTC values.

Table 3
Median NTC [MW] for each border between the 11 studied countries.

To From	BE	DK	FR	DE-AT-LU	GB	IE	IT	NL	PT	ES	CH
Belgium			700					1200			
Denmark				1285							
France	2000			1200	2000		2681			2500	3000
Germany-AT-LU		2100	1800				272	1468			2400
Great Britain			2000			980		1016			
Ireland					707						
Italy			995	100							1810
Netherlands	950			1468	1016						
Portugal										3000	
Spain			2200						2100		
Switzerland			1200	5200			2759				

Note: missing observations were replaced by the median value of NTC for the corresponding interconnection. When hourly NTC data was not available, daily or weekly forecast NTC values were used instead.

Table 4
First panel: total costs in autarky [million EUR/year], and changes in total costs for the other scenarios (a negative sign corresponds to cost savings). Second panel: average realized LOLE for the two countries (computed using the domestic priority rule) under each scenario. Third panel: obtained total installed capacity (sum of both countries) under each scenario.

	Total costs (M EUR)				Average realized LOLE (hours)				Total installed capacity (MW)			
	(1)	(2)	(3)	(4)	(1)	(2)	(3)	(4)	(1)	(2)	(3)	(4)
Country-pair	Autarky	ΔNational	ΔRegional	ΔOptimal	Autarky	National	Regional	Optimal	Autarky	National	Regional	Optimal
Belgium-France	6142.2	2.9	−1.4	−3.0	1.1	3.6	3	2.1	102,010	101,120	101,315	101,772
Belgium-Netherlands	1875.2	7.6	−2.7	−3.4	0.6	5	3	1.8	31,219	30,757	30,962	31,082
Denmark-Germany	5278.1	15.5	−3.0	−7.8	1.1	3.9	3	1.6	87,402	85,962	86,646	86,859
France-Germany	10283.3	−19.3	−29.9	−36.9	1	3.6	3	2.4	170,974	168,142	168,748	169,435
France-Great Britain	8612.7	−66.5	−66.5	−66.5	0.9	3	3	3	143,274	140,633	140,633	140,633
France-Italy	8224.2	−137.6	−137.6	−137.6	0.6	3	3	3	136,938	133,456	133,456	133,456
France-Spain	7495.1	−89.9	−126.2	−134.7	0.1	4.2	3	2.1	124,915	120,410	121,230	121,643
France-Switzerland	5933.9	1.8	−0.6	−2.5	1	3.4	3	2.2	98,499	97,863	97,983	98,322
Germany-Italy	7902.9	−2.0	−2.0	−2.0	2.6	3	3	3	130,238	130,092	130,092	130,092
Germany-Netherlands	6061.4	5.8	1.5	−1.1	1.4	3.1	3	2.5	100,184	99,310	99,527	99,975
Germany-Switzerland	5563.2	10.0	0.4	−0.5	1.2	3.4	3	2.1	91,799	90,974	91,394	91,718
Great Britain-Ireland	3597.2	−8.2	−10.9	−11.9	1.1	3.2	3	2.4	58,992	57,964	58,511	58,511
Great Britain-Netherlands	4392.9	−11.2	−9.9	−12.1	1.5	3	3	2.4	72,483	70,848	71,208	71,208
Italy-Switzerland	3465.8	−7.2	−34.4	−49.5	0	5.5	3	1.5	57,763	55,667	56,348	56,610
Portugal-Spain	2680.1	−1.6	−5.6	−6.3	1.4	3.8	3	2.1	44,258	43,100	43,447	43,724

Table 5
Results for the complete interconnected power system of 11 countries.

	(1)	(2)s	(3)	(4)
	Autarky	National assessment	Regional assessment	Optimal
Total costs (M EUR/ year)	22,108	22,385	21,254	21,244
Total installed capacity (GW)	368.5	340.6	348.7	349.6
Average realized LOLE	0	10.6	3	2.3

for the security of supply benefits enabled by sharing installed capacities through interconnectors.[17]

Overall, the outcome reached by a regional assessment that uses realized LOLE levels instead of the correct ones $\widehat{LOLE}_i$ is often very close to the optimal one in terms of total costs. However, it differs significantly from the optimal benchmark for a number of country pairs (e.g. France-Germany, France-Spain, or Italy-Switzerland). In particular, in two cases, the installed capacities obtained with an incorrect regional assessment yield total costs that are slightly *higher* than the total costs obtained with autarky installed capacities. Indeed, because the domestic priority rule ignores a fraction of the security of supply benefits obtained by the neighboring country, too little capacity ends up being installed. The subsequent increase in the opportunity cost of unserved energy happens to outweigh the savings in investment costs. In both cases, the corresponding inefficiencies are however relatively small. By contrast, naive national adequacy assessments can yield very contrasted outcomes. In some cases, e.g. France-Great Britain or France-Italy, maximum achievable cost savings are realized. In other cases, e.g. Belgium-Netherlands or Denmark-Germany, the outcome reached is significantly more costly than the autarky outcome due to an underinvestment in generation capacities.

Table 5 shows the obtained results for the 11 countries and 15 interconnectors considered as a single power system. Installing autarky generation capacities is found to induce a total cost of 22,108 M€. Autarky capacities add up to almost 370 GW.[18] Conditional on having installed these generation capacities, the realized LOLE (averaged over

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[17] Note that the metric we report as “total costs” ignores both fuel costs and the decrease in investment costs that may be achieved through the use of a portfolio of generation technologies. As a result, this number should not be taken at face value. However, differences in total costs across scenarios are meaningful because they do capture the first-order impact of alternative adequacy assessment methodologies. Indeed, during hours of peak consumption, the relevant economic trade-off is the choice between investing in more peaking capacity or accepting that higher load curtailment levels in expectations (fuel costs being negligible relative to the value of lost load).

[18] This is an underestimation of the actual total capacity, as we neglect generation that is needed for ancillary services.

countries) is negligible – much below the LOLE target, as also noted by Newbery (2016). The first-best outcome would however be to downsize the generation fleet by 18.9 GW and curtail more load in expectation. The corresponding expected savings in terms of total costs are very significant and amount to 864 M€/year.

Perhaps somewhat surprisingly, the regional assessment scenario yields total cost savings of 854 M€/year relative to the autarky scenario, which represents 99% of achievable savings. The obtained total installed capacity is comparable to the first-best benchmark (349 GW vs 350 GW). However, country-level installed capacities can differ significantly, and may not be unique. For some countries, the difference in obtained installed capacity under the regional assessment and the first-best benchmark is found to exceed 10% of the first-best capacity. This observation thus calls for caution when using the outcome of regional adequacy assessments as an input for setting country-level assumptions or targets for installed generation capacity.

Finally, our application to the full power system illustrates that naive national adequacy assessments can yield a very sub-optimal outcome. Under our “national assessments” scenario, because countries assume in their domestic adequacy assessment that their neighbors have installed their autarkic capacities, they all overestimate the extent to which they can rely on interconnectors, and thus end up significantly downsizing their generation fleet. As a result of this coordination failure, realized total installed capacity is 9 GW lower than under the optimal outcome. Total costs exceed the autarky cost by several hundred millions euros per year because of the resulting massive amount of load curtailments.

5. Conclusion and policy implications

This paper studies the consistency between two contradictory policies in the electricity industry. On the one hand, electricity systems are increasingly interconnected. On the other hand, reliability standards, whose value was typically set when countries were hardly interconnected, are still enforced at the national level. Using a simple theory model, we show that historical reliability standards defined in the absence of interconnections can still be used in interconnected electricity systems. However, their continued use still leads to the social optimum only under two necessary conditions: reliability simulations performed in generation adequacy assessments should (i) be coordinated across interconnected countries to rely on consistent assumptions about installed capacity in neighboring countries; and (ii) compute domestic reliability levels in a generalized sense, which internalizes the lost load that domestic capacity may avoid throughout the entire interconnected system. We further run numerical simulations using publicly available data on 11 European countries to assess the relative importance of both requirements, and find that regional coordination is the most critical one in our case study.

Our results have three main policy implications. First, our numerical application investigates empirically for the case of Europe the relative importance of the two necessary conditions for national reliability standards to maximize welfare. We find regional coordination to be much more important than fully internalizing external reliability benefits in adequacy simulations. This result supports the recent legislation enacted in Europe to implement a regional adequacy assessment by 2023 (ACER, 2020 *b*). The generation adequacy assessment methodology would still benefit from further clarifying how national expected loss of load expectations should be calculated, but the bulk of efficiency benefits can be expected to arise from simply coordinating on consistent assumptions. This result is useful for ACER and NRAs when they define how generation adequacy assessments should be performed. Second, our findings make it clear that TSOs, when they run their adequacy simulations, should make sure that they compute simulated LOLE levels correctly and that they share their assumptions and/or coordinate their simulations. Third, our theoretical analysis shows that historical reliability standards defined in the absence of interconnections do not necessarily need to be discarded. This conclusion is important for national policy makers because they are typically very reluctant to transfer this responsibility to a supra-national level, as ensuring national security of supply involves high economic, social, and political stakes. However, as countries become more and more interconnected, the increasingly-important requirement for coordinating national assessments will gradually transform them into a regional adequacy assessment. During the learning phase of trial and error, reliability standards can still be used, as they are not inconsistent with an optimal (regional) adequacy assessment. But once a regional adequacy assessment is fully implemented, national assessments and national reliability standards will be redundant.

Whether the conclusions derived from our empirical exercise apply to regions other than Europe is to some extent an open question. National power systems in Europe are much more interconnected than most other power sytems around the world. An over-optimistic reliance on interconnectors in times of power scarcity has however been found to be one of several factors contributing to the rolling blackouts in California of August 2020. Yet, other considerations may be of primary importance to achieve a reliable electricity supply. For example, the power crisis of February 2021 in Texas has stressed the importance of energy availability – like natural gas or coal – for generation adequacy.

Finally, given the importance of ensuring reliable electricity supply, there is ample room for further work on reliability standards and generation adequacy. First, the fundamental parameters underlying the numerical value of historical reliability standards may change dramatically over time. With new storage technologies, demand response and variable renewables, it is increasingly challenging to correctly estimate the value of lost load, long-term marginal capacity cost, the probability of future peak load and the probability distribution of generation availability. Second, the power markets currently in place around the world are still far away from following textbook economics principles, and a number of market failures are relatively well-understood if not documented. Exploring how market inefficiencies and strategic behaviors interact with generation adequacy assessments thus provides many areas for further research.

Data availability

The data used in this article is publicly available at https://transparency.entsoe.eu/. The code and corresponding final datasets are available on the authors’ websites.

Declaration of competing interest

The authors declare that they have 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 Proofs

To simplify notations and without loss of generality we set $\underline{D}_1 = \underline{D}_2 = 0$.

Proof of proposition 2

Proof.

The cost minimization problem is then:

$$\begin{aligned}\min_{K_1,K_2} \quad & \gamma(K_1+K_2) \\ & + \int_0^{K_1-L_{12}} \int_0^{K_2+L_{12}} c(D_1+D_2) f(D_1,D_2) dD_2 dD_1 \\ & + \int_0^{K_1-L_{12}} \int_{K_2+L_{12}}^{+\infty} [c(D_1+K_2+L_{12}) + V(D_2-K_2-L_{12})] f(D_1,D_2) dD_2 dD_1 \\ & + \int_{K_1-L_{12}}^{K_1+L_{21}} \int_0^{K_1+K_2-D_1} c(D_1+D_2) f(D_1,D_2) dD_2 dD_1 \\ & + \int_{K_1-L_{12}}^{K_1+L_{21}} \int_{K_1+K_2-D_1}^{+\infty} [c(K_1+K_2) + V(D_1+D_2-K_1-K_2)] f(D_1,D_2) dD_2 dD_1 \\ & + \int_{K_1+L_{21}}^{+\infty} \int_0^{K_2-L_{21}} [c(D_2+K_1+L_{21}) + V(D_1-K_1-L_{21})] f(D_1,D_2) dD_2 dD_1 \\ & + \int_{K_1+L_{21}}^{+\infty} \int_{K_2-L_{21}}^{+\infty} [c(K_1+K_2) + V(D_1+D_2-K_1-K_2)] f(D_1,D_2) dD_2 dD_1\end{aligned}$$

For better understanding, Fig. 4 shows the areas corresponding to the six double integrals of the cost minimization problem.

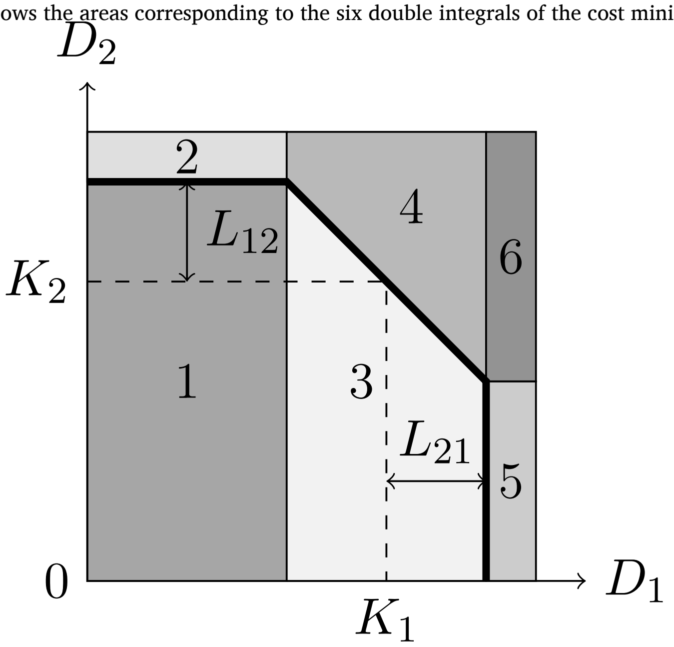

Fig. 4. Areas corresponding to the six double integrals of the cost minimization problem.

The first-order condition with respect to K_1 equals:

$$
\begin{aligned}
&\gamma + \int_{0}^{K_2+L_{12}} c(K_1 - L_{12} + D_2) f(K_1 - L_{12}, D_2) dD_2 \\
&+ \int_{K_2+L_{12}}^{+\infty} [c(K_1 + K_2) + V(D_2 - K_2 - L_{12})] f(K_1 - L_{12}, D_2) dD_2 \\
&+ \int_{0}^{K_2-L_{21}} [c(K_1 + L_{21} + D_2)] f(K_1 + L_{21}, D_2) dD_2 \\
&- \int_{0}^{K_2+L_{12}} [c(K_1 - L_{12} + D_2)] f(K_1 - L_{12}, D_2) dD_2 \\
&+ \int_{K_1-L_{12}}^{K_1+L_{21}} c(K_1 + K_2) f(D_1, K_1 + K_2 - D_1) dD_1 \\
&+ \int_{K_1-L_{12}}^{K_1+L_{21}} \int_{K_1+K_2-D_1}^{+\infty} (c - V) f(D_1, D_2) dD_2 dD_1 \\
&- \int_{K_2+L_{12}}^{+\infty} [c(K_1 + K_2) + V(D_2 - L_{12} - K_2)] f(K_1 - L_{12}, D_2) dD_2 \\
&+ \int_{K_2-L_{21}}^{+\infty} [c(K_1 + K_2) + V(D_2 + L_{21} - K_2)] f(K_1 + L_{21}, D_2) dD_2 \\
&- \int_{K_1-L_{12}}^{K_1+L_{21}} c(K_1 + K_2) f(D_1, K_1 + K_2 - D_1) dD_1 \\
&- \int_{0}^{K_2-L_{21}} [c(D_2 + K_1 + L_{21})] f(K_1 + L_{21}, D_2) dD_2 \\
&+ \int_{K_1+L_{21}}^{+\infty} \int_{0}^{K_2-L_{21}} (c - V) f(D_1, D_2) dD_2 dD_1 \\
&- \int_{K_2-L_{21}}^{+\infty} [c(K_1 + K_2) + V(L_{21} + D_2 - K_2)] f(K_1 + L_{21}, D_2) dD_2 \\
&+ \int_{K_1+L_{21}}^{+\infty} \int_{K_2-L_{21}}^{+\infty} (c - V) f(D_1, D_2) dD_2 dD_1 = 0
\end{aligned}
$$

Which simplifies to:

$$
\gamma + \int_{K_1+L_{21}}^{+\infty} \int_{0}^{+\infty} (c - V) f(D_1, D_2) dD_2 dD_1 + \int_{K_1-L_{12}}^{K_1+L_{21}} \int_{K_1+K_2-D_1}^{+\infty} (c - V) f(D_1, D_2) dD_2 dD_1 = 0
$$

■

Proof of proposition 3

Proof. With asymmetric VoLLs and short-term operation rules that prioritize domestic load, the cost minimization problem becomes:

$$
\begin{aligned}
\min_{K_1, K_2} \quad & \gamma(K_1 + K_2) \\
&+ \int_{0}^{K_1-L_{12}} \int_{0}^{K_2+L_{12}} c(D_1 + D_2) f(D_1, D_2) dD_2 dD_1 \\
&+ \int_{0}^{K_1-L_{12}} \int_{K_2+L_{12}}^{+\infty} [c(D_1 + K_2 + L_{12}) + V_2(D_2 - K_2 - L_{12})] f(D_1, D_2) dD_2 dD_1 \\
&+ \int_{K_1-L_{12}}^{K_1+L_{21}} \int_{0}^{K_1+K_2-D_1} c(D_1 + D_2) f(D_1, D_2) dD_2 dD_1 \\
&+ \int_{K_1-L_{12}}^{K_1} \int_{K_1+K_2-D_1}^{+\infty} [c(K_1 + K_2) + V_2(D_1 + D_2 - K_1 - K_2)] f(D_1, D_2) dD_2 dD_1 \\
&+ \int_{K_1}^{K_1+L_{21}} \int_{K_1+K_2-D_1}^{K_2} [c(K_1 + K_2) + V_1(D_1 + D_2 - K_1 - K_2)] f(D_1, D_2) dD_2 dD_1 \\
&+ \int_{K_1}^{\infty} \int_{K_2}^{\infty} [c(K_1 + K_2) + V_1(D_1 - K_1) + V_2(D_2 - K_2)] f(D_1, D_2) dD_2 dD_1 \\
&+ \int_{K_1+L_{21}}^{+\infty} \int_{0}^{K_2-L_{21}} [c(D_2 + K_1 + L_{21}) + V_1(D_1 - K_1 - L_{21})] f(D_1, D_2) dD_2 dD_1 \\
&+ \int_{K_1+L_{21}}^{+\infty} \int_{K_2-L_{21}}^{K_2} [c(K_2 + K_1) + V_1(D_1 + D_2 - K_1 - K_2)] f(D_1, D_2) dD_2 dD_1
\end{aligned}
$$

Fig. 5 shows the areas corresponding to the eight double integrals of the cost minimization problem.

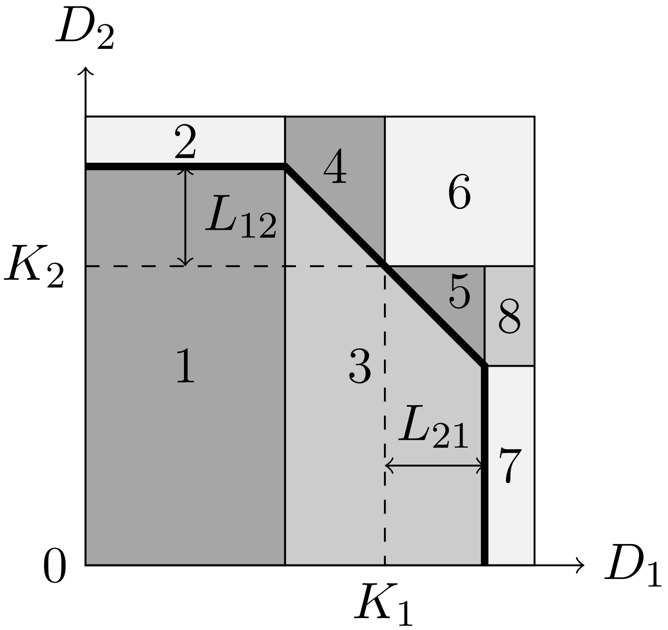

Fig. 5. Areas corresponding to the eight double integrals of the cost minimization problem with asymmetric VoLLs.

In regions 1 and 3, load can be supplied in both countries. In regions 2 and 4, only country 2 curtails load (since $D_1 \leq K_1$). The amount of energy curtailed however depends on whether the interconnector is used at full capacity (region 2) or not (region 4). In region 6, both countries need to curtail load. Finally, in regions 5, 7 and 8, only country 1 is curtailing load (since $D_2 \leq K_2$). Again, the amount of energy curtailed however depends on whether the interconnector is used at full capacity (region 7) or not (regions 5 and 8).

First-order conditions with respect to K_1 and K_2 yield equation (12). _

B Generalization to the N-country case

Two-country case

We discuss for now the two-country case to illustrate the intuition behind our methodology to compute $\widehat{LOLE}_i$. Our objective is to show that we can define a methodology to assess – in the context of adequacy assessment simulations – the probability $\widehat{LOLE}_i$ of curtailing load in country i such that setting a target $\widehat{LOLE}_i = \alpha$ for all countries minimizes total costs.

$\widehat{LOLE}_i$ is formally the expectation over demand realizations (D_1, D_2) of a function $LL_i(.)$:

$$\widehat{LOLE}_i \equiv \mathbb{E}_{(D_1,D_2)}[LL_i(D_1, D_2 \mid K_1, K_2, L_{12}, L_{21})] \tag{14}$$

where LL_i takes the value 1 if a demand realization (D_1, D_2) should, given installed capacities K_1, K_2, L_{12}, L_{21}, be considered (in adequacy assessment simulations) to trigger load curtailments in country i.

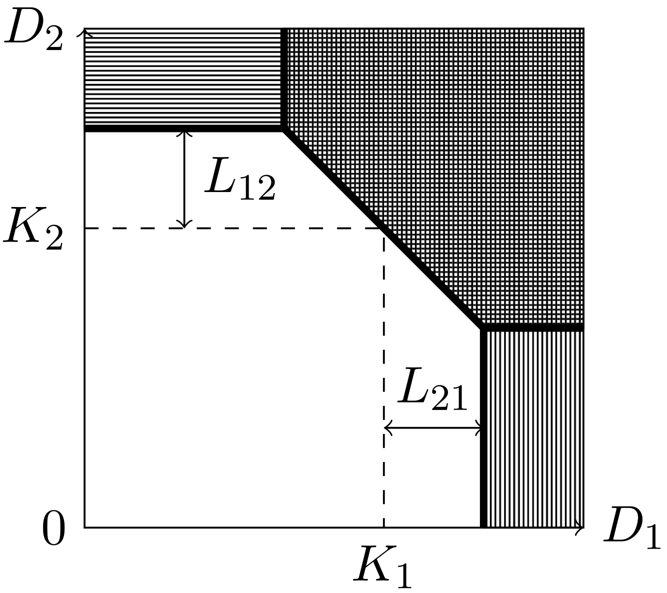

Fig. 6. Illustration of how country-specific LOLE should be computed in adequacy assessments to ensure that enforcing the autarky reliability standard remains consistent with welfare maximization. Demand realizations that fall in the area with vertical (resp. horizontal) lines imply curtailments in country 1 (resp. country 2). Lost-load is considered to happen in both countries in the grided area.

From the first-order condition of Proposition 2, we get the following corollary:

Corollary 3 In the two-country case, country-specific reliability standards are consistent with the first-best outcome if LL_i is constructed as follows:

1. *Identify the subset of countries $Z^* \in \{\varnothing, \{1\}, \{2\}, \{1, 2\}\}$ that is experiencing the most severe capacity shortage:*

$$Z^* = \begin{cases} \varnothing & \text{if } \max(D_1 + L_{21} - K_1, D_2 + L_{12} - K_2, D_1 + D_2 - K_1 - K_2, 0) = 0 \\ \{1\} & \text{if } \max(D_1 + L_{21} - K_1, D_2 + L_{12} - K_2, D_1 + D_2 - K_1 - K_2, 0) = D_1 + L_{21} - K_1 \\ \{2\} & \text{if } \max(D_1 + L_{21} - K_1, D_2 + L_{12} - K_2, D_1 + D_2 - K_1 - K_2, 0) = D_2 + L_{12} - K_2 \\ \{1,2\} & \text{if } \max(D_1 + L_{21} - K_1, D_2 + L_{12} - K_2, D_1 + D_2 - K_1 - K_2, 0) = D_1 + D_2 - K_1 - K_2 \end{cases}$$

2. *Then define LL_i as follows:*

$$LL_i(D_1, D_2 \mid K_1, K_2, L_{12}, L_{21}) = \begin{cases} 1 & \text{if } i \in Z^* \\ 0 & \text{otherwise} \end{cases}$$

In words, Corollary 3 states that for each demand realization (D_1, D_2) where shedding load is necessary ($Z^* \neq \varnothing$), adequacy assessment simulations should identify the subset of countries for which the capacity shortage is the most severe. The capacity shortage faced by a group of countries is defined as total load minus domestic and import capacities, assuming full availability of imports. In the context of adequacy assessments, lost load should be assumed to take place in each country that belongs to this subset of countries. Fig. 6 illustrates graphically that this approach is consistent with welfare-maximization first-order conditions for the two-country case. Indeed, taking for example the perspective of country 1, the area covered by vertical stripes does correspond to the LOLE region under the own altruism rule in Fig. 2.

Extension to N countries

We denote $\mathbf{D} \equiv (D_1, \ldots, D_N)$ the realization of the vector of demand in each country for a given hour and $\mathbf{K} \equiv (K_1, \ldots, K_N)$ the vector of installed capacities. We further denote L_{ij} the interconnection capacity from country i to country j. Our objective is to define for which realizations of D adequacy assessment simulations should consider that lost load occurs in country i given installed capacities K and $\{L_{ij}\}_{ij}$.

To do so, we define:

$$Z^*(\mathbf{D} \mid \mathbf{K}, L_{ij}) \equiv \begin{cases} argmax_{Z \subseteqq \{1,\ldots,N\}} \sum_{i \in Z} D_i - \sum_{i \in Z} K_i - \sum_{j \notin Z} \sum_{i \in Z} L_{ij} & \text{if } \max_{Z \subseteqq \{1,\ldots,N\}} \sum_{i \in Z} D_i - \sum_{i \in Z} K_i - \sum_{j \notin Z} \sum_{i \in Z} L_{ij} > 0 \\ \varnothing & \text{otherwise} \end{cases}$$

For given K and $\{L_{ij}\}_{ij}$, we will show that the adequacy assessment should consider that lost load occurs in country i for hourly demand realization D if, and only if:

$i \in Z^*(\mathrm{D} \mid \mathrm{K}, L_{ij})$

We start by showing that, when a demand vector is not feasible, the amount of electricity curtailed is:

$LL(\mathrm{D} \mid \mathrm{K}, L_{ij}) \equiv \max_{Z \subseteqq \{1, \ldots, N\}} \sum_{i \in Z} D_i - \sum_{i \in Z} K_i - \sum_{j \notin Z} \sum_{i \in Z} L_{ij}$

Let E be the quantity of electricity curtailed in a non-feasible state. For a given subset $Z \subseteqq \{1, \ldots, N\}$ of countries, we denote:

$LL(Z \mid \mathrm{D}, \mathrm{K}, L_{ij}) \equiv \max(\sum_{i \in Z} D_i - \sum_{i \in Z} K_i - \sum_{j \notin Z} \sum_{i \in Z} L_{ij}; 0)$.

Because any subset of countries cannot procure more electricity than the sum of their domestic and import capacities, we have for all $Z \subseteqq \{1, \ldots, N\}$:

$E \geq LL(Z \mid \mathrm{D}, \mathrm{K}, L_{ij})$.

and thus:

$E \geq LL(\mathrm{D}\ |\mathrm{K}, L_{ij})$.

Reciprocally, let Z^* be the largest set of countries where load may need to be curtailed despite using all the capacity of installed generators and interconnectors. For any partition $\{z_1, \ldots, z_p\}$ of Z^*, that is mutually exclusive subsets of Z^* such that $\cup_{i=1}^{p} z_i = Z^*$, we have:

$LL(Z^* \mid \mathbf{D}, \mathbf{K}, L_{ij}) \geq \sum_{i=1}^{p} LL(z_i \mid \mathbf{D}, \mathbf{K}, L_{ij})$

In other words, looking separately at the constraints faced by sub-groups of countries cannot imply higher amounts of lost load. As a result:

$E \leq LL(Z^*\ |\mathrm{D}, \mathrm{K}, L_{ij}) \leq LL(\mathrm{D}\ |\mathrm{K}, L_{ij})$.

We thus have $E = LL(\mathrm{D}\ |\mathrm{K}, L_{ij})$.

Short-term cost

Knowing how much energy is curtailed in each demand state, the short-run cost $c_{SR}(\mathrm{D}\ |\mathrm{K}, L_{ij})$ to serve a vector of demand D is:

$$c_{SR}(\mathbf{D} \mid \mathbf{K}, L_{ij}) = \left(\sum_{i=1}^{N} D_i - \max(LL(\mathbf{D} \mid \mathbf{K}, L_{ij}), 0) \right) \times c + \max(LL(\mathbf{D} \mid \mathbf{K}, L_{ij}), 0) \times V \tag{15}$$

Long-term cost

Let $f(.)$ denote the probability density of demand vectors D. The long-term cost $c_{LR}(\mathrm{K} \mid L_{ij})$ of installing capacities K is:

$$c_{LR}(\mathbf{K} \mid L_{ij}) \equiv \gamma \sum_{i=1}^{N} K_i + \int_{\mathbf{D}} c_{SR}(\mathbf{D} \mid \mathbf{K}, L_{ij}) f(\mathbf{D}) d\mathbf{D} \tag{16}$$

First-order conditions

From Equation (15), we have:

$$\partial_{K_i} c_{SR}(\mathbf{D} \mid \mathbf{K}) = \begin{cases} -(V - c) & \text{if } i \in Z^*(\mathbf{D} \mid \mathbf{K}) \\ 0 & \text{otherwise} \end{cases}$$

As a consequence, minimizing long-term costs with respect to K yields the first-order conditions:

$$\forall i \in \{1, \ldots, N\}, \int_{\mathbf{D}} \mathbf{1}_{i \in Z^*(\mathbf{D} \mid \mathbf{K})} f(\mathbf{D}) d\mathbf{D} = \alpha \tag{17}$$

where $\mathbf{1}_{i \in Z^*(\mathbf{D} \mid \mathbf{K})}$ is a dummy variable that takes the value 1 if country i is in $Z^*(\mathrm{D}\ |\mathrm{K})$ and 0 otherwise.

The underlying intuition is the same as in the two-country case. For each hour, one must identify the set of countries facing the most stringent level of scarcity. All countries belonging to that set must then be considered to incur lost-load for this hour.

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