Assessment of generation adequacy taking into account the dependence of the European power system on natural gas

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by

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Abstract

Reductions in gas supply following the Russian invasion of Ukraine have affected the security of supply of the European power system along with other stress factors like low availability of French nuclear reactors. Consequently, more sophisticated approaches to investigate generation adequacy and to anticipate risks in security of supply are needed. Especially a thorough assessment of generation adequacy taking into account both the variability of renewable infeed and the availability of thermal power plants based on a probabilistic approach has been missing so far. In this paper, we apply a novel integrative approach to analyze generation adequacy in a case study for Central Western Europe during the winter half year 2022/2023. The approach makes use of a multivariate probabilistic framework built on publicly available data. For assessing generation adequacy, stochastic distributions are fitted to the data and Monte Carlo simulations are performed to identify future threats to generation adequacy. Results show that based on data available at the end of September 2022, generation adequacy (GA) was at risk in several core European countries, yet that the European interconnected power grid contributed to a strong risk reduction.

Keywords: Security of Supply, Generation Adequacy, Probabilistic, Monte Carlo, Energy System Modeling

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Abbreviations

cdf	cumulative distribution function
CHP	combined heat and power
EENS	expected energy not served
GA	generation adequacy
LOLE	loss of load expectation
NTC	net transfer capacities
RES	renewable energy sources

1 Introduction

1.1 Motivation

The 2022 Russian invasion of Ukraine and the subsequent reductions in Russian natural gas flows to the EU have increased the potential for natural gas shortages in the short term. With 32 % of natural gas being used in power generation (Eurostat 2022b), a decrease in the availability of natural gas might also affect the security of supply of the European power system. In the power systems of many countries, a substantial share of renewable electricity generation goes along with natural gas power plants being used to cover the peak load and, when operated as a combined heat and power (CHP) unit, also to supply heat to industry and heating networks.

In addition to a risk regarding gas availability for natural gas power plants, the year 2022 saw also a significant reduction in availability for the French nuclear power fleet mainly due to the detection of stress corrosion and required maintenance work with a year-on-year reduction of -22 % in cumulative output (EDF 2022).

Developing a power system mainly based on renewable energy sources (RES) and increasing electrification is a key decarbonization strategy of the EU (European Commission 2019). While the former, due to the intermittent nature of RES, results in a more volatile and weather-dependent power system, the latter leads to an increase in electricity demand. Consequently, to balance the variable power generation of a power system with high RES shares, the importance of dispatchable generation units and other flexibilities increases, when it comes to ensuring the security of supply.

One key aspect of the security of electricity supply is generation adequacy (GA), referring to the ability of installed generation capacities to supply electricity demand (European Commission 2017). While deterministic assessments of GA are used frequently (Joint Research Centre et al. 2016), they are not able to assess weather-related uncertainties as well as uncertainties regarding the availability of thermal generation units due to technical failures, operational constraints, and context factors. On the contrary, probabilistic methodologies are able to evaluate the probability of occurrences of scarcity events based on underlying uncertainties and their dependencies.

Consequently, generation adequacy assessments, both in the ongoing European energy crisis and in future power systems with high shares of RES, have to rely preferably on probabilistic methods to quantify the probability of scarcity events critical for security of supply.

1.2 Literature Review

Security of power supply is one pillar of the European climate and energy policy and encompasses several dimensions. Here, we focus on GA as the ability of the generation of the power system to match the electricity demand at all points in time. Countries of the EU are legally obligated to regularly assess GA to ensure cost-effective and reliable power supply (European Commission 2017).

Approaches to assessing GA are distinguished based on the applied deterministic and probabilistic methods. Traditionally, GA has been assessed by capacity balances, where the balance between secured generation capacity and electricity demand is calculated for specific scenarios of the power system and for selected points in time (ENTSO-E 2015; German Transmission System Operators 2018). This deterministic method can be implemented with limited modeling effort, calculations require low computation time, and yield comprehensible results. However, capacity balances neglect significant uncertainties and temporal dependencies in the power system, with a risk of oversimplifying the power system. As German Transmission System Operators (2022) indicate, capacity balances continue to be used for operational assessments of GA. But state-of-the-art assessments for strategic planning of the power system use probabilistic methods (European Commission 2017).

Probabilistic methods aim to examine all constraining system states and quantify the uncertainty for the power system due to electricity demand, RES infeed, and thermal power plant availability. Grave et al. (2012) extend deterministic capacity balances with joint probability functions determined by the stochastic convolution of density functions of wind infeed and available thermal generation capacity. Iivo Vehviläinen (2021), in a similar approach, additionally incorporate hydro storages and evaluate GA using technical probabilistic indicators. Probabilistic capacity balances analyze peak load situations under uncertainty but neglect persistent critical situations due to temporal-dependent effects such as storage operation or dark doldrums.

In a Monte-Carlo simulation, a large number of power system states are examined depending on their probability of occurrence. This enables the evaluation of the power system under uncertainty. Guerrero-Mestre et al. (2020), ENTSO-E (2021) and Gils et al. (2018) use sequential Monte-Carlo simulations in GA assessments to simulate temporal-dependent unplanned power plant outages as a key source of uncertainty (affecting the availability of generation capacity). Uncertainty from weather effects in volatile RES infeed or electricity demand is accounted for by using scaled historical time series in so-called climate years/weather years. The GA is assessed by combining a number of weather years describing both RES infeed and electricity demand with simulations of available generation capacity. Previous research shows that the GA assessments of interconnected networks benefit from incorporating spatial dependencies (Tomasson and Söder 2017; Kloubert 2020; Kockel et al. 2022), cross-border exchanges (Baumanns et al. 2017), and interdependence among uncertainty variables.

Hydro storages provide flexibility to the power system to balance intermittent RES infeed. Although some hydro storages depend on seasonal inflows, they are essential for the GA of several power systems. However, the determination of the operation of hydro storages for a number of simulations and considering temporal dependencies is complex. Crosara et al. (2019) use a heuristic approach to assess available hydro storage generation capacity. ENTSO-E (2021) and Gils et al. (2018) optimize the operation of hydro storages based on simulations of RES infeed and the availability of generation capacity.

In longer-term power system analysis, future generation capacity requirements to ensure GA are determined using fundamental models (Hladik et al. 2018; ENTSO-E 2021). Here, the interplay between market prices and generation investments and desinvestments is another key element in addition to power infeed and electricity demand simulations.

As the number of simulations and model complexity increase, the computational run time of GA assessment approaches increases. Tomasson and Söder (2017) show in a multi-area GA assessment that with importance sampling techniques the number of simulations may be reduced without sacrificing accuracy. Tindemans and Strbac (2020) use a multilevel Monte-Carlo framework to improve the computational efficiency of GA assessment. Nolting and Praktiknjo (2020) develop a meta-model using a neuronal network to reduce the computational effort of simulation-based GA assessments.

With a share of around 12 % of total gross electricity generation in the EU27 generated by CHP units (Eurostat 2022a), consideration of weather-dependent availability factors of CHP units due to variability in heat demand appears to be a relevant determinant in GA assessments. Nevertheless, so far, the dependency of GA on the availability of CHP units has not been extensively studied. In most assessments, it is assumed that CHP units are fully available (e.g. Consentec and r2b (2015)). In their adequacy assessment, Praktiknjo et al. (2022) consider mandatory dispatch for CHP power plants with the assumption that priority is given to the obligation to satisfy heat demand.

While the effect of natural gas supply shortages on GA assessments have historically not been a thoroughly studied subject, there is now a significant increase in research interest due to the circumstances of the current European energy crisis. Praktiknjo et al. (2022) investigate the dependency of the European electric power system on natural gas. Using a probabilistic resource adequacy model that considers weather-related uncertainties and uncertainties due to outages of conventional generation units, the authors deduce values for the reliability metric *expected energy not served (EENS)* in three 2025 scenarios: a 30 % and a 40 % reduction in available natural gas volumes, and a reference scenario without any reduction in natural gas availability. While there is a substantial increase expected shortage of electricity supply of 1.6 TWh in the 30 % reduction scenario compared to the reference scenario, the expected shortage of electricity supply further increases to 37.8 TWh in the 40 % reduction scenario, mainly occurring in Ireland, Italy, and the UK. In a sequential Monte-Carlo simulation, ENTSO-E (2022b) analyzed resource adequacy for winter 2022/2023 on pan-European level under several stress factors: low hydro levels in Southern Europe and Southern Norway, low nuclear availability in France and fossil fuel supply risks in Germany and Poland. In a scenario with combined sensitivities, they find substantial adequacy risks in France, Ireland, Poland, and Finland and additionally determine a critical gas volume to ensure resource adequacy of 411 TWh which exceeds historical gas demands by 12 %. Wagner et al. (2022) model the potential development of electricity prices and unit commitment for the German and French electricity market during Winter 2022/2023. Using the weather year 2015 and three scenarios that differ in the assumptions regarding the availability of French and German nuclear power plants, they derive the use of natural gas in power generation. The authors come to the conclusion that the delay of the 2022 decommissioning of nuclear power plants may reduce natural gas consumption in the electricity sector by 2 % or 3 TWh. Using an empirical approach, Ruhnau et al. (2022) estimate the crisis response of natural gas consumer groups in Germany (small consumers, industry and power stations) with a multiple regression model controlling for the non-linear temperature-heating relationship, seasonality, trends and economic activity in the time period from September 2021 until September 2022. The authors estimate a significant aggregated reduction of natural gas consumption by as much as 18 TWh/month, or 30 % of baseline consumption, for September 2022.

1.3 Added Value and Research Question

This study presents a novel methodology for the comprehensive quantification of power system uncertainties and probabilistic assessment of GA. While other studies use weather years, this study models multiple power system uncertainties as stochastic processes and generates a large number of uncertainty realizations in a large-scale Monte-Carlo simulation to assess GA. In addition to fundamental seasonal variations in RES infeed and electricity demand, we model their spatio-temporal dependencies and unit-wise availability of thermal power plants as introduced in Section 2. For the application of the methodology to assess the GA in core European countries, we focus on a use case of winter 2022/2023. Additional stress factors risk GA in winter 2022/2023 in Europe exceeding the usual uncertainty of the power system, namely limited natural gas flows from Russia, low availability of French nuclear power plants, and potential heating substitution by electrical heating. We examine scenarios to investigate the effect of these additional stress factors on GA. Our research questions are as follows:

- What is the impact of the reduction of Russian natural gas flows on the GA in core European countries in winter 2022/2023?
- What effect does the availability of thermal generation capacities have on the GA in the core European countries?

The remainder of this paper is structured as follows: The comprehensive model for the assessment of GA is presented in Section 2. In section 3, the specifications of the case study are stated and its results are discussed in the subsequent Section 4. In the last Section 5, the findings of the paper are summarized, and policy implications are given.

2 Methodology

We aim to quantify and evaluate the uncertainty in the power system for GA using large sample Monte-Carlo simulations. Our approach is based on Bellenbaum et al. (2022) and additionally models spatio-temporal dependencies of RES infeed, temperature, and electricity demand. Further, we model filling level restrictions limiting the generation of storage power plants as well as temporal dependencies and CHP restrictions on the availability of thermal power plants. As indicated in Figure 1, the approach can be divided into five major steps: In step I, the stochastic characteristics and fundamental effects of RES infeed and temperature-dependent electricity demand are estimated in a quantile regression based on historical data for n considered regions (typically countries). In addition, step II estimates the fundamental effects on the availability of thermal power plants using empirical data. Then, we use a sequential Monte-Carlo simulation to generate realizations: step I uses a vector-autoregressive model to simulate RES infeed, temperature, and electricity demand to calculate the residual load. The simulations reflect fundamental effects and stochastic dependencies. In parallel, the availability of thermal power plants is simulated in step II with a semi-Markov model considering planned and forced power plant outages as well as restrictions due to heat obligations based on a simplified heat dispatch model. In step III, storage operation is estimated. Thereby a deterministic optimization is carried out for a subset of realizations from I and II and the results are generalized to all realizations using a regression approach. In step IV, the remaining free capacity is first computed separately for each region. Negative free capacities imply that generation adequacy only can be achieved through cross-regional exchanges. These are then determined in a simple electricity trading model based on net transfer capacities (NTC). Finally, the results are collected: any occurrence of negative free capacities in some region during a time step in one or several Monte-Carlo realizations implies that GA is not attained. These occurrences are summarized in step V to derive probabilistic indicators for GA assessment. More detail on the different steps are given in the following subsections.

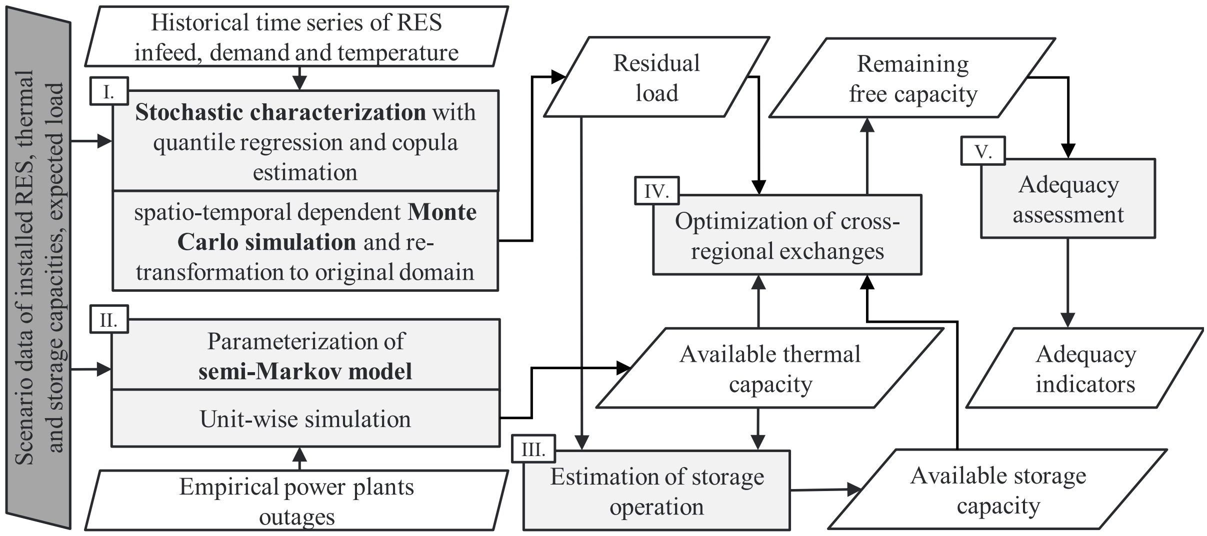

Figure 1: General approach

2.1 Step I: Simulation of Residual Load

The residual load $Y_r^R(t)$ (also sometimes called net load) is computed as the difference between electricity demand $Y_r^L(t)$ and the infeed of variable RES.

$$Y_r^R(t) = Y_r^L(t) - Y_r^{WOn}(t) - Y_r^{WOff}(t) - Y_r^{PV}(t) - Y_r^H(t) \tag{1}$$

It includes key uncertainties relevant for the assessment of generation adequacy. Correspondingly, we analyse the infeed from onshore and offshore wind turbines $Y_r^{WOn}(t)$ resp. $Y_r^{WOff}(t)$, photovoltaic $Y_r^{PV}(t)$, and run-of-river power plants $Y_r^H(t)$ separately to identify deterministic components (e.g., linked to seasonal effects) along with stochastic variations. Thus, we account for multiple sources of uncertainty, such as solar irradiation, water inflow, or wind speed. Temperature is also modelled as a stochastic process as well as electricity demand. Thereby, temperature is used as an explanatory factor for electricity demand.

Tastu et al. (2015) and Papaefthymiou and Kurowicka (2008) show that spatial and temporal dependencies are central in multi-regional uncertainty modeling of the power system. Following Sklar's theorem (Sklar 1959), the marginal distribution for each time series $y_{r,h}^c(t)$ (also labelled "uncertainty factor" subsequently) is estimated first. Then the dependency structure is analysed using copulas. Thereby deterministic effects (e.g. seasonal and daily cycles) have to be eliminated first for each uncertainty factor to avoid describing spurious correlations (or more generally: interdependencies). To do so, we use quantile regressions based on normalized observations $y^{c}_{r,h}(t)$ for each region r at each hour of the day h. Quantile regressions are for example discussed by Koenker (2005) and enable the non-parametric estimation of marginal distributions and a more adequate estimation of rare (extreme) events compared to standard linear regressions assuming normally distributed errors. Equation 2 gives the regression function for onshore wind infeed $y^{WOn}_{r,h|q}(t)$. With t measured in years, the trigonometric terms with full year and half-year period length are used as a smooth functional approximation of arbitrary deterministic seasonal effects [1]. The regression parameters $\alpha^{WOn}_{0...4,r|q}$ are estimated for each quantile q. For electricity demand, we include additional regressors for heating and cooling degree-days to reflect the impact of electric heating and air-conditioning as well as further temperature-dependent effects.

$$
\begin{aligned}
y^{WOn}_{r,h|q}(t) = \quad & \alpha^{WOn}_{0,r,h|q} + \alpha^{WOn}_{1,r,h|q} \cdot cos(2\pi \cdot t) + \alpha^{WOn}_{2,r,h|q} \cdot sin(2\pi \cdot t) \\
& + \alpha^{WOn}_{3,r,h|q} \cdot cos(4\pi \cdot t) + \alpha^{WOn}_{4,r,h|q} \cdot sin(4\pi \cdot t) + \varepsilon^{WOn}_{r,h|q}(t)
\end{aligned} \tag{2}
$$

The regression function in Equation 2 is used to estimate the cumulative distribution function (cdf) $\hat{F}^{c}_{r,h}(t)$. Next, the marginal distribution of each uncertainty factor c is separated from its dependency structure following the approach of Papaefthymiou and Kurowicka (2008). So, the cdf of each uncertainty factor is mapped onto a uniform distribution $q^{c}_{r,h|q}(t)$ and subsequently onto a normal distribution (cf. Equation 3 and 4). The normally distributed data $\tilde{y}^{c}_{r,h}(t)$ represent transformed quantiles of the estimated marginal distributions without deterministic effects, but including the dependence structure. Further, we analyze and model the multivariate dependence structure based on $\tilde{y}^{c}_{r,h}(t)$ to generate realizations of each uncertainty factor.

$$
\hat{F}^{c}_{r,h}(y^{c}_{r,h|q}(t)) = q^{c}_{r,h|q}(t) \tag{3}
$$

$$
\Phi^{-1}(q^{c}_{r,h|q}(t)) = \tilde{y}^{c}_{r,h}(t) \tag{4}
$$

[1] The trigonometric terms correspond to the first two terms of a Fourier series decomposition with ex ante unknown phase angle

Vector autoregressive models are widely used in multivariate time series analysis, especially in economics and finance, because of their ability to model interdependencies and dynamic relationships among multiple variables (Lütkepohl 2005). Therefore, we fit a vector autoregressive model for each uncertainty factor c for a set of r time series variables with r corresponding to the number of considered regions. The covariance matrices represent the instantaneous spatial relationship between the regions. We generate $i = 1000$ realizations of $Q^c_{r,i}(t)$ for each uncertainty factor per region and scenario period. Subsequently, the realizations are re-transformed onto the marginal distributions characterized via the quantile regressions.

2.2 Step II: Simulation of the Availability of Thermal Power Plants

In the second step (cf. Figure 1), we model the availability of power generation from thermal power plants affected by planned maintenance and forced power plant outages, plus restrictions due to heat obligations. The key uncertainty for the availability of thermal power plants is unpredictable outages due to technical failures. Therefore, we use a semi-Markov model to generate unit-wise realizations of the availability of thermal power plants such that the realizations satisfy the Markov property (Spilger and Weber 2023). The semi-Markov model incorporates fundamental effects and enables time-varying and non-parametric parameterization (Billinton and Allan 1996; Barbu et al. 2004). For parameterization, we use empirical data from ENTSO-E (2022a). Furthermore, restrictions in the availability of CHP units due to heat obligations are considered through the application of a heat dispatch model described in Felten (2020) that derives heat demand at the individual district heating network level and subsequently determines heat supply schedules of individual heat generation units for each network which in turn impose restrictions on the electricity production capabilities of the plants (cf. also Furtwängler and Weber (2019)).

2.3 Step III: Determination of Storage Operation

Storage power plants offer flexibilities to balance the power system by charging and discharging the storages. The storage operation of seasonal storage power plants is essentially influenced by seasonal inflows. But current and expected power market developments significantly influence the operation of storages and subsequently their ability to discharge in times of power shortages. In step III (cf. Figure 1), the available generation capacity from storage power plants in consideration of filling level constraints is determined using an approximation approach that combines intertemporal optimization of storage operation for a small subset of realizations with a linear regression. The linear regression implies an averaging of storage operation over the realizations which avoids overfitting to individual realisations computed with (unrealistic) perfect foresight. We include regressors for seasonal effects, residual load and available thermal generation capacities in the linear regression.

2.4 Step IV: Computation of Cross-regional Exchanges

As load shortfalls in individual regions can be compensated for by neighboring countries in the European power system, an appropriate assessment of cross-border exchanges is key for multi-regional GA assessments. To do so, for all simulations the remaining free capacity $RC_{i,r}(t)$ of single regions is calculated using the outcomes for residual load, available thermal, and storage generation capacities as determined in the previous steps (cf. Sections 2.1 - 2.3.) For the subset of realizations with negative free capacity in any region, cross-regional exchanges are determined that minimize the remaining negative free capacity. Thereby a simple static trading exchange model based on NTC is applied that is sufficiently rapid to accommodate also large-scale Monte-Carlo samples. As an outcome, the (negative) free capacity in the interconnected power system $RC'_{i,r}(t)$ is obtained for each realization and each time step and can be compared to the negative free capacity in single regions considered in isolation.

2.5 Step V: Computation of Adequacy Indicators

According to regulation (EU) 2019/943, reliability standards used to monitor and steer the security of electricity supply of EU member states are to be expressed based on the indicators loss of load expectation (LOLE) and expected energy not served (EENS) (Council of European Union 2019). For the GA assessment in this study, we use these indicators according to the definition in ACER (2020). Both indicators are calculated based on the remaining free capacity $RC'_{i,r}(t)$ of which negative values indicate the amount of electricity demand that cannot be covered in realization i during time step t within region r. The Equation 5 states that LOLE per region r is calculated as the expected number of time steps t with negative $RC'_{i,r}(t)$ and is given as the sum over all time steps $t \in [0T]$. In addition, in Equation 6 EENS quantifies the total expected $RC'_{i,r}(t)$ in the entire time period T.

$$LOLE_r = \sum_t^T \mathbb{E}\left[\mathbb{1}_{RC'_{i,r}(t)<0}\right] \tag{5}$$

$$EENS_r = \sum_t^T \mathbb{E}\left[\max\left\{0, -RC'_{i,r}(t)\right\}\right] \tag{6}$$

3 Case Study

3.1 Scope and Data

The model presented in Section 2 is applied in a case study to assess the GA during winter 2022/2023 from 01.10.2022 - 31.03.2023 for the following core European countries: Austria (AT), Belgium (BE), Switzerland (CH), Czech Republic (CZ), Germany (DE), Denmark (DK), France (FR), Italy (IT), Netherlands (NL) and Poland (PL). Data from ENTSO-E (2021) are used to estimate the seasonalities and the stochastic dependencies of RES infeed and electricity demand as presented in Section 2.1. The semi-Markov model for the simulation of available thermal power plants is parameterized based on empirical data from 2018 to 2022 (ENTSO-E 2022a). Scenario data of installed power plant capacities, cumulative electricity demand, and net transfer capacities are based on the recent years as provided by ENTSO-E (2022a) in September 2022. Furthermore, commodity prices reflect the average of future contracts for 2023 traded from June until the end of August 2022 (Energate 2022).

3.2 Scenarios

In this case study, we evaluate the GA in five scenarios described in Table 1 that reflect the geopolitical events and the specific situation in continental Europe in autumn 2022. The objective is to assess the combined effects of usual stochastic events like RES infeed and power plant outages and the specific risks that have given raise to serious concerns about security of supply in the investigated core European countries. In addition, the case study enables the analysis of model performance.

Table 1: Overview of evaluated scenarios

ID	Scenario	Description
S1	Reference	Based on expectations at the end of 2021
S2	Gas shortage	Available generation capacity from natural gas power plants reduced by 30 %
S3	Nuclear outage	Incorporation of predicted available generation capacity from French nuclear power plants by end of September 2022
S4	Heating substitution	Increased temperature sensitivity of electric demand in Germany
S5	Combined	Combination of scenarios S2 to S4

For the reference scenario S1, the electricity demand and the installed and available generation capacities are determined for the scenario period based on expectations at the end of 2021 (ENTSO-E 2021). These data are adjusted for the extension of the run time of German nuclear power plants as decided by the German government (Deutscher Bundestag 2022).

As the reduction of Russian natural gas flows to Central Western Europe during 2022 could limit the amount of natural gas available for power generation, the effect of such gas flow restrictions on the GA is analyzed in a gas shortage scenario S2. For this scenario, we assume that all CHP obligations are met as a priority to avoid shifting of demand shortfalls to the heating sector. However, the limited fuel availability of gas-fired power plants affects GA primarily at peak load. Thus, we limit the available generation capacity of all gas-fired power plants for the entire scenario period to 70 % of their installed generation capacity. No explicit limit is placed on the total amount of gas available.

Another stress factor for the winter 2022 / 2023 has been the low availability of the French nuclear power fleet during summer and autumn 2022. This has been an additional motivation for the extension of the run time of the remaining German nuclear power plants was extended until April 2023. In a further scenario, called the nuclear outage scenario S3, we examine these changes in the availability of French nuclear power plants on the GA. In this scenario, forecasts regarding the availability of French nuclear power plants are considered instead of their historical availabilities. According to the forecasts used, approx. 40 GW of French nuclear power plants are available until November, after which availability gradually increases to approx. 55 GW in January.

Further, as a consequence of limited Russian natural gas flows, also the gas supply for heating is potentially at risk. In response, a partial substitution of natural-gas heating by electric heating might arise. In this heating substitution scenario S4, we model a situation where half of the German households heating with natural gas make use of a small electric heating device with a nameplate capacity of 2 kW. This corresponds to an additional nameplate capacity of 10 GW which may be activated at very low temperatures. Regarding the impact of this additional heating energy demand on the hourly demand profiles, we use data on the French temperature sensitivity (RTE 2021) which we scale proportionally to the nameplate capacity.

In a final scenario (S5), the co-occurrence of a reduction in natural gas power plant generation capacities, a reduction in the availability of the French nuclear power fleet, and increased temperature sensitivity of electric demand in Germany is modeled.

4 Results and Discussion

The assessment of GA in core European countries for winter 2022/2023 is subsequently discussed using the adequacy indicators introduced in Section 2.5. Table 2, presents the key results for the reference scenario S1 both in terms of LOLE and EENS, with and without consideration of cross-regional exchanges. Additionally, the simulation results are compared to the national reliability standards as indicated in ACER (2022).

Without the consideration of cross-regional exchanges, the LOLE indicator yields positive values for all countries except Switzerland, Denmark, and Italy. Especially in Belgium and France

Table 2: National reliability standards according to ACER (2022) and adequacy indicators in reference scenario S1 without and with consideration of cross-regional exchanges

	LOLE in h		EENS in MWh		National reliability standard as LOLE in h
	Isolated	Connected	Isolated	Connected	
DE	0.01	0.00	7.24	0.00	2.77
AT	2.99	0.00	1379.25	0.00	
BE	101.75	0.66	66 764.10	280.82	3.00
CH	0.00	0.00	0.00	0.00	
CZ	0.04	0.00	5.94	0.00	15.00
DK	0.00	0.00	0.28	0.00	
FR	10.10	0.24	28 591.91	462.07	2.00
IT	0.00	0.00	0.00	0.00	3.00
NL	0.18	0.00	70.08	0.00	4.00
PL	0.05	0.02	29.63	5.34	3.00

GA is severely impaired, with a respective LOLE of 101.75 hours and EENS of 66 764.1 MWh in Belgium and 10.1 hours and 28 591.91 MWh in France. Critical LOLE above the national reliability standards are reached in Austria, Belgium, and France. With consideration of cross-regional exchanges, the LOLE is equal to zero (at two digits precision) in the reference scenario S1 in most countries except for Belgium, France, and Poland. As in the case without cross-regional exchanges, we identify the highest LOLE values for Belgium with an expectation of 0.66 hours of power shortfalls. In contrast, France has the highest energy not served, yet the LOLE is only 0.24 hours per year. The higher value of EENS obviously is related to the bigger size and the correspondingly higher electricity demand of the country.

Figure 2 illustrates graphically the occurrences of EENS with consideration of cross-regional exchanges during the scenario period. It shows that scarcity events may occur in Belgium during the entire scenario period, whereas in France they are limited to the period between end of December and beginning of March. Correspondingly, France has rather high EENS values in individual hours. The results suggest a systematic lack of available power in Belgium induced by limited generation capacities and import capabilities. In contrast, the scarcity events in France are rather related to its high share of temperature-sensitive electricity demand. The significantly lower LOLE and EENS values in the case with cross-regional exchanges show that grid interconnection severely decreases GA risks, especially in Belgium and France. Overall, all computed LOLE remain below the respective national reliability standards, indicating prima facie that GA is met in the reference

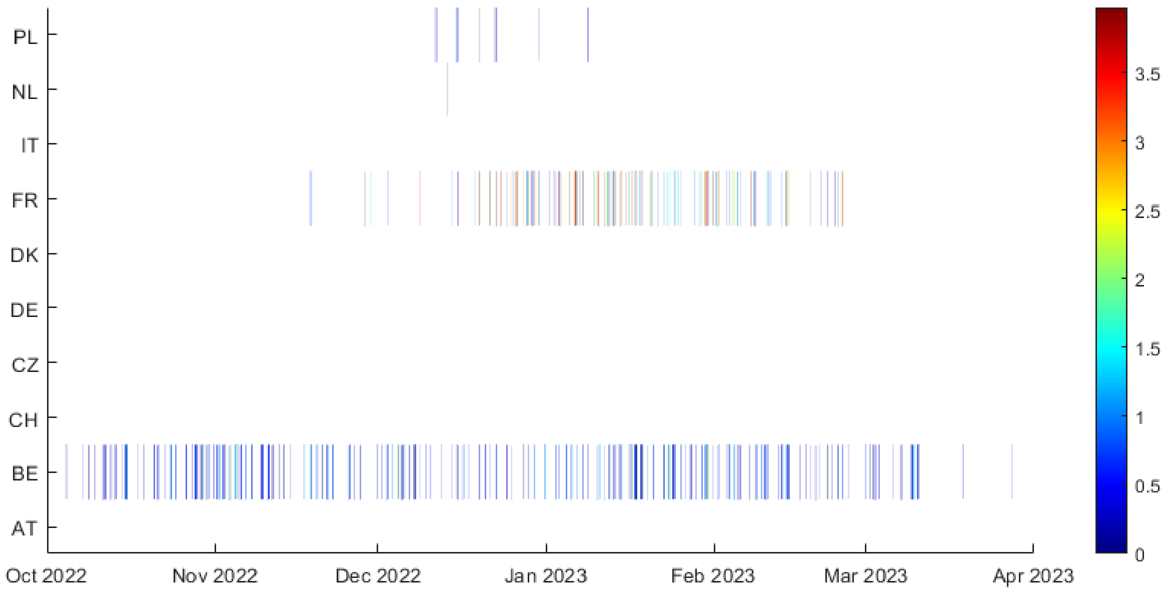

Figure 2: Expected energy not served (EENS) per hour in MWh for the reference scenario S1 with consideration of cross-regional exchanges

scenario S1. This is unquestionable despite the fact that the reliability standards are set for a full year whereas the calculations focus on the winter half year. But typically load and residual load attain their maximum during the winter half-year so that two times the numbers indicated in Table 2 is an upper bound to the annual LOLE.

Table 3: Average loss of load expectation (LOLE) in hours for all investigated scenarios in an interconnected power system

ID Scenario	S1 Reference	S2 Gas shortage	S3 Nuclear outage	S4 Heating substitution	S5 Combined
AT	0.00	0.00	0.00	0.00	0.19
BE	0.66	17.78	0.39	0.66	35.36
CH	0.00	0.01	0.00	0.00	1.01
CZ	0.00	0.00	0.00	0.00	0.00
DE	0.00	0.00	0.00	0.00	1.44
DK	0.00	0.00	0.00	0.00	0.07
FR	0.24	1.59	0.80	0.24	7.17
IT	0.00	0.51	0.00	0.00	1.50
NL	0.00	2.08	0.00	0.00	3.47
PL	0.02	0.16	0.01	0.02	0.14

The adequacy indicators for the remaining scenarios are summarized in Tables 3 and 4. In the gas shortage scenario S2, as the available generation capacity from gas-fired power plants during peak load is reduced (in total by 38 GW), the LOLE increases especially in Belgium. But also in the Netherlands and France, scarcity events increase substantially, attaining almost the level set by the national reliability standards. Further positive LOLE values, albeit smaller, are observed in Italy, Poland, and even Switzerland. For the Netherlands and Italy, the results reflect the high share of power generation from gas-fired power plants, namely 49.5 % in Italy and 46.5 % in the Netherlands (IEA 2022a; IEA 2022b). Praktiknjo et al. (2022) find similar effects with higher EENS in the aforementioned countries when the available gas volume is reduced by 30 %. The findings of Praktiknjo et al. (2022) are in line with our results, indicating also that GA is not ensured in the gas shortage scenario S2 in Belgium.

Table 4: Average expected energy not served (EENS) in MWh for all investigated scenarios in an interconnected power system

ID Scenario	S1 Reference	S2 Gas shortage	S3 Nuclear outage	S4 Heating substitution	S5 Combined
AT	0.00	0.00	0.00	0.00	0.00
BE	280.82	10 387.22	167.13	281.57	23 266.52
CH	0.00	5.33	0.00	0.00	550.39
CZ	0.00	0.00	0.00	0.00	0.00
DE	0.00	0.00	0.00	0.68	3535.29
DK	0.00	0.00	0.00	0.00	0.38
FR	462.07	4047.20	1649.98	466.76	23 077.36
IT	0.00	423.05	0.00	0.00	1528.09
NL	0.00	1145.23	0.00	0.00	2343.84
PL	5.34	78.82	5.82	5.34	69.09

In the nuclear outage scenario S3, both adequacy indicators triple in France compared to the reference scenario S1 with a total EENS of 1.64 GWh. Thus, the number of scarcity events in France increases, but the expected power deficit per scarcity event does not. Moreover, the scarcity events concentrate from December to March with varying level of EENS. According to our results, GA is yet maintained in France with a LOLE of 0.80 hours, which is below the national reliability standard of 2.00 hours.

Besides these effects in France, only the adequacy indicators in Belgium change in S3 compared to the reference scenario S1. Table 3 shows a decrease in LOLE in Belgium from 0.66 hours in S1 to 0.39 hours in S3. This is a counter-intuitive result at first sight since the only adjustment in scenario S3 is a reduction in availability of French nuclear power plants. A closer look reveals that in comparison to S1 and S2, less scarcity events are determined in Belgium at the end of the scenario period. On the other hand, it turns out that the forecasts for the availability of French nuclear power plants used in this scenario exceed the realizations in S1 at the end of the winter period. Correspondingly, more power can be exported from France to Belgium at the end of the scenario period in S3 than in S1 and the LOLE decreases in Belgium.

In the heating substitution scenario S4, the results indicate no substantial effects on GA. Despite an increase of peak load in Germany by up to 10 GW, the increase in expected power deficits in Germany is very limited, the LOLE remains below 0.01 h and for EENS, a value smaller than 1 MWh is obtained.

Overall, the individual adjustments in scenarios S2, S3, and S4 have minor to moderate effects on GA. The most critical effects are observed in the gas shortage scenario S2, where the available capacity of gas-fired power plants is reduced by 30 % in all analyzed regions.

In the combined scenario S5, the LOLE is however strictly positive in all countries except the Czech Republic. In Germany, 1.44 hours of LOLE come along with 3.53 MWh of EENS. Figure 3 illustrates that scarcity events with varying intensities are expected from December to March in Germany and France and in Belgium the scarcity events prevail over the entire winter season - as well as in the Netherlands, albeit there to a lower extent. The high EENS in individual hours in Germany is caused by the combination of volatile electricity generation, the increased temperature sensitivity of electricity demand, and limited conventional generation capacities. The two latter factors also induce a total of 7.17 hours of LOLE in France, which exceeds the corresponding national reliability standard of 2.00 hours (for a whole year). Furthermore, Table 3 illustrates that countries with a positive LOLE in S1 are particularly affected in S5. Again, the highest LOLE is observed in Belgium, which exceeds the national reliability standard for a whole year by more than a factor ten. Also in the Netherlands, the reliability requirements are not met, albeit the LOLE and the EENS are much lower. This reveals structural deficits in generation capacities that can not be compensated by the neighboring countries in such a high-stress scenario. Overall, the results of the combined scenario S5 show that the simultaneity of scarcity events in multiple regions reduce the compensating effects of cross-regional exchanges and hydro storages on the GA.

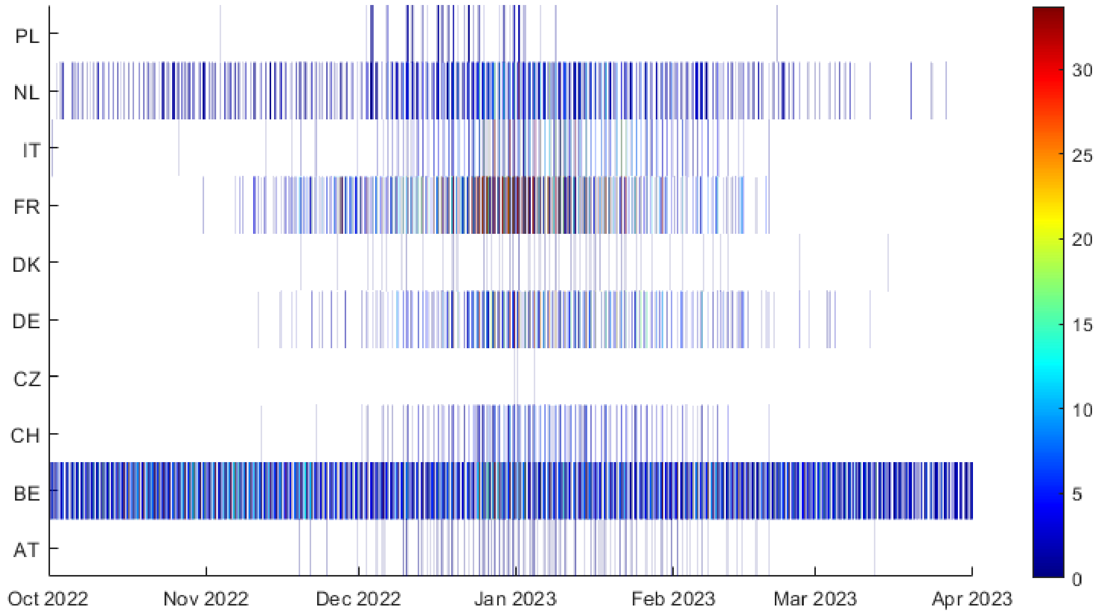

Figure 3: Expected energy not served (EENS) per hour in MWh for the combined scenario S5

5 Conclusions and Policy Implications

In this paper, we present a case study using a comprehensive framework for the assessment of generation adequacy (GA) - i.e., the ability of the power system to meet electricity demand at all times. First, the uncertainties of the power system critical for GA are quantified considering their empirical distributions and spatio-temporal dependencies over the past years. These include the infeed of onshore and offshore wind, photovoltaics, and run-of-river power plants as well as partly temperature-dependent variations in electricity demand. In addition, the uncertainty regarding the availability of thermal power plants is modeled based on an empirical parameterization of a semi-Markov model. Thereby, we incorporate planned and forced power plant outages and CHP restrictions. This detailed characterization of uncertainties enables a thorough assessment of the probability of rare events of scarcity, in which GA is threatened. By generating 1000 hourly realizations of the uncertainty factors in a Monte-Carlo simulation, we create a large event sample to characterize the stochastics of the power system. This enables a valid assessment of GA.

In the case study, the focus is on the GA assessment for winter 2022/2023, where several extraordinary threats to GA have been identified ex-ante. Correspondingly, we have analyzed the impacts of reduced Russian natural gas flows to Central Western Europe, extensive outages of

French nuclear power plants and increased electricity demand in Germany resulting from heating substitutions due to increased gas prices. As observations of similar events in recent history are nonexistent or very rare, they are modeled through dedicated scenarios. These scenarios reflect additional stress on the electricity system that comes on top of the ordinary stochastic fluctuations. Individually, the analyzed events have moderate impacts on GA except for the reduction of the available capacity of gas-fired power plants. Yet in a combined scenario, the resulting scarcities significantly affect the GA in most investigated countries, especially in Belgium and France with both over 23 GWh of EENS and the LOLE substantially exceeding the nationally set reliability standards.

The comparison of adequacy indicators with and without consideration of cross-regional exchanges shows that storage power plants and cross-regional exchanges compensate for scarcity events in individual countries in scenarios S1 to S4. But when the multiple stress factors arise simultaneously, available power generation and transmission capacities in core European countries turn out to be insufficient, and simultaneous scarcity events occur across Europe.

The reference scenario suggests that the combination of markets and state regulations in Europe has so far ensured GA. But the analyses show that since the end of 2021, new threats have emerged which induce substantial risks for the European power system: fossil fuel shortages and extended outages of nuclear power plants. As these risks are likely to persist through winter 2023/2024, there is a need for regular probabilistic GA assessments in the near future. Though regular short-term assessments of GA are required by law (c.f. regulation (EU) 2019/941), hardly any comprehensive probabilistic assessments have been carried out so far. In ENTSO-E (2022b), a probabilistic approach was used to evaluate GA in winter 2022/2023, but it largely accounts only for stochastic variations due to weather years. However the focus of these assessments should be, as in the framework presented in this paper, to quantify comprehensively the uncertainties in the power system and to assess the risk of multiple simultaneous stress factors.

In the longer term future, power systems will be dominated by RES infeed and have to cope with lower conventional capacities. Consequently, security of supply will be potentially at greater risk and probabilistic assessments will gain in importance. In this perspective, the combined role of different storage technologies such as battery and hydrogen storage requires particular scrutiny.

Advanced probabilistic methods need to be developed to assess their combined contributions in a systems context to ensure GA in the future. In addition, the interplay between energy markets and capacity mechanisms deserves closer scrutiny in order to ensure security of supply while transforming the energy system.

The analysis is limited by an incomplete geographical scope of the case study, a lack of consideration of demand-side flexibility, and a simplified representation of of supply-side flexibility. While we implicitly assume that reserve generation capacity is available to prevent scarcity events, this assumption has to be validated. Further work needs to be done to develop a stochastic dynamic programming approach to determine the available storage generation capacity and to analyze the impact of drought periods affecting the availability of hydro and thermal generation capacities on GA. Additionally, more research should focus on understanding compound risks of GA and transmission adequacy, such as dependencies of power and gas systems and their effects on GA.

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