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Impact of coordinated capacity mechanisms on the European power market

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Impact of Coordinated Capacity Mechanisms on the European Power Market

HEMF Working Paper No. 01/2017

by

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January 2017

UNIVERSITÄT
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Open-Minded

Impact of Coordinated Capacity Mechanisms on the European Power Market

by Michael Bucksteeg*, Stephan Spiecker, Christoph Weber

Abstract

There is an ongoing debate on the introduction of capacity markets in most European countries while a few of them have already established capacity markets. Since the implementation of independent national capacity markets is not in line with the target of a pan-European internal electricity market we investigate the impacts of uncoordinated capacity markets compared with coordinated capacity markets. A probabilistic approach for the determination of capacity requirements is proposed and a European electricity market model (E2M2s) is applied for evaluation. The model simultaneously optimizes investments and dispatch of power plants. Besides the impact on generation investments, market prices and system costs we analyse effects on production and security of supply. While coordinated capacity markets reveal high potentials for cross border synergies and cost savings, uncoordinated and unilateral implementations can lead to inefficiencies, in particular free riding effects and endanger security of supply due to adverse allocation of generation capacity.

Keywords: capacity markets, system adequacy, market design

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1 Introduction

Over the last two decades, power markets in Europe have been liberalized and competition has been introduced into the wholesale markets. At the same time a European emissions trading scheme has been introduced and renewable technologies have been supported in most European countries. As a consequence previously regulated utilities face a more dynamic world with various uncertain and stochastic parameters. In this new environment, investment decisions in generation facilities are based on revenues gained in the energy-only market and are therefore dependent on adequate price signals. Moreover, they are subject to insecure future conditions notably with respect to the development of renewable capacities, electricity demand, CO₂- and fuel-prices as well as regulatory uncertainties (cf. Hasani and Hosseini 2011).

In theory, competitive energy-only markets incentivise optimal investments in new generation capacities in line with the peak load pricing approach (cf. e.g. Boiteux 1960 or Stoft 2002). In practice, market imperfections however lead to a violation of the assumptions behind the peak load pricing theory. Especially, the long lead times for generation investments and the absence of demand response prevent reaching a situation of market equilibrium. As a result there are reasonable concerns about insufficient investment incentives in restructured electricity markets, which would lead to supply shortages and endanger system adequacy. While in theory the adequacy problem can be avoided by sufficient short-term demand elasticity, in practice electricity markets are characterised by low demand flexibility at present. Thus, in order to ensure an adequate long-term allocation of generation capacities, different capacity mechanisms have been proposed and implemented in recent years (cf. e.g. Cramton and Ockenfels 2012).

In several European countries (e.g. Poland, Sweden, Finland) a strategic reserve operated by the TSO was implemented. In order to avert a capacity shortage, the system operator contracts a certain volume of generation capacity. This reserve capacity is made available to the electricity market at a price significantly higher than the marginal cost of generation. While in many European countries (e.g. Germany, Belgium, Italy) there is ongoing debate on the introduction of capacity markets, only a few countries (United Kingdom, France) recently implemented capacity markets (cf. e.g. Creti et al. 2012; Newbery 2011). In this context capacity markets can be understood as a market

instrument to allocate and provide the level of generation capacity that minimizes the duration of supply shortages.

Cramton and Ockenfels (2012) note that strategic reserves would not reduce investment risks and thus would likely suppress new investments and compromise long-term reliability of a power system. Both, Cramton and Ockenfels (2012) and de Vries and Heijnen (2008) note that capacity markets perform best in terms of a lower price volatility and system reliability. Consequently, we focus on capacity markets within this paper and analyse the impacts on the European power market.

In recent years mainly national debates brought out several and heterogeneous capacity market models (cf. e.g. ACER 2013; Creti et al. 2012; Newbery 2011). However, as the EU member states aim for an internationalization of the electricity sector and an integration of national power systems, the implementation of unilateral national capacity markets is not expedient. The target model for the implementation of the internal market focuses on an integrated energy market but does not foresee a capacity market design (cf. European Commission 2011). So far, few studies have addressed the impacts of capacity markets in interconnected power markets. Cepeda and Finon (2011) study the impacts of heterogeneous market designs on generation adequacy using a stylised two-country model. Their results contradict the intuition that in the case of unilateral capacity mechanisms countries without adequacy policies would free-ride in the long-term. Heterogeneous capacity mechanisms rather lead to negative externalities compromising the efficiency of neighbouring energy-only markets. Meyer and Gore (2015) apply a game-theoretic two-country model and analyse cross-border effects of strategic reserves and reliability options. They find that unilateral capacity mechanisms lead to competition effects increasing benefits for consumers in both countries but reducing producer surplus in the country without capacity mechanism. Accordingly, the missing-money problem would be exacerbated leading to decommissioning of generation capacities. However, in both studies the impacts on a large scale power system like the European one and the resulting security of supply are not investigated.

Tasios et al. (2014) deploy a model of the European electricity market and compare EU-wide symmetric (homogeneous national) and asymmetric (unilateral national) capacity mechanisms. They also find that an asymmetric implementation of capacity mechanisms induces market distortions and inefficiencies. However, they do not model generation

investments endogenously and apply capacity payments based on the missing money resulting from a wholesale market simulation, hence ignoring interactions between energy-only and capacity markets.

The present paper analyses the impacts of different capacity market designs on the European power market and adds to the current literature by filling the following gaps: First, in addition to symmetric and asymmetric capacity markets we also consider two EU-wide coordinated capacity market designs, which are in line with the internal electricity market. To the authors knowledge so far several studies have addressed the effects of symmetric and asymmetric capacity markets (cf. Tasios et al. 2014; Cepeda and Finon 2011), but not the impacts of coordinated capacity markets. Second, we apply a probabilistic approach for a consistent determination of capacity requirements. For the cases of coordinated capacity markets this approach is extended to a multiregional or transnational level. Third, we assess the long-term development with an electricity market model (E2M2s) in order to consider interactions between energy-only and capacity markets. The model covers the European power system and generation investments are modelled endogenously (cf. Spiecker et al. 2013 and Spiecker et al. 2014). Besides economic effects, the impacts on security of supply utilising the probabilistic approach are also analysed.

The remainder of this article first describes the applied methodology in section 2. A probabilistic approach for the determination of capacity requirements is presented and a description of the applied model is included. Subsequently the investigated scenarios and input data are reviewed. In section 3 model results are presented and economic effects and arising implications for security of supply are discussed. The article ends with brief conclusions on the achieved results.

2 Methodology

2.1 General Approach

The procedure implemented in this study to analyse the different capacity market designs can be divided into four major steps (Figure 1): (I.), inputs are prepared, covering electricity demand (and RES generation profiles), the installed power plant fleet and unscheduled generation unavailabilities. (II.), capacity requirements using a probabilistic

sizing approach are computed. (III.), short- and long-term equilibria are determined utilising an electricity market model. (IV.), the endogenously calculated generation investments are used to assess the resulting level of security of supply (e.g. LOLP).

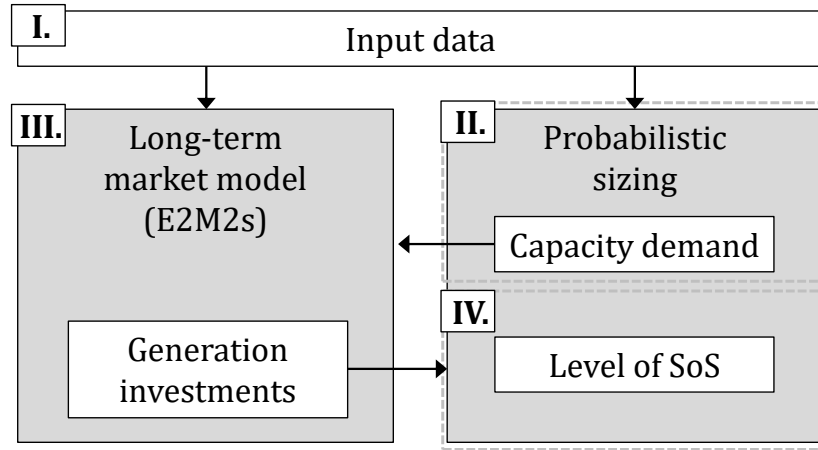


Figure 1: General approach

2.2 Probabilistic Sizing of Capacity Requirements

The effectiveness and efficiency of capacity markets is dependent on an adequate determination of capacity requirements. Due to long lead times of power plant construction, capacity requirements have to be forecasted three to five years ahead. The dimensioning of generation capacity in order to secure an adequate supply during peak load hours is particularly dependent on the availability of generation units and the predicted development of (residual) power demand. Main drivers of demand for electricity are economic development, regulatory framework, energy efficiency measures as well as future climate and weather conditions.

An adequate methodology for the determination of capacity requirements has therefore to consider the stochastic superposition of power demand imbalances, intermittent renewables generation and unplanned generation outages. While in practice and also in literature (cf. e.g. Cepeda and Finon 2011) the capacity requirements are determined based on the expected peak load plus a reliability margin, we apply a probabilistic convolution approach.

Besides an incorporation of the stochastics of unscheduled generation unavailabilities and power demand, the convolution approach allows the consideration of intermittent renewables generation. Moreover, it accounts for the non-simultaneity of random events

(e.g. plant outages, peak load) at the regional or European level in the case of coordinated capacity mechanisms beyond national power markets. By this means too high capacity requirements and hence excessive provision of generation capacity can be avoided.

In most power systems supply shortages are tolerated to a certain degree (e.g. 1 hour in 10 years). Hence, when determining the capacity requirement it has to be ensured that the available generation capacity is almost always sufficient to cover the electricity demand in the respective hour. Or in other words, the frequency of a remaining capacity less than zero should not exceed the tolerated degree or security level. The remaining capacity ψ is calculated by formula (1) where the available generation capacity in hour h is given by $C(h)$ and the load in hour h is referred to as $L(h)$.

$$\psi(h) = C(h) - L(h) \quad (1)$$

The available generation capacity $C(h)$ depends on the installed generation capacity C_{icap} and the probability of a forced outage or unexpected unavailability of generation units. Hence, both $C(h)$ and $L(h)$ are realizations of random variables and can be described by their statistical distributions. The cumulative distribution function of the remaining capacity ψ can then be determined by a convolution of the distributions of (residual) load (cumulative distribution $F_{L(h)}$) and of the available generation capacity of all units (cumulative distribution $F_{C(h)}$). According to Laplace's method (cf. Laplace 1812), we make use of the probability density function $f_{C(h;C_{icap})}$ for the generation capacity and introduce C_{icap} as design variable that impacts the distribution. The cumulative distribution function F_ψ of the remaining capacity is then given by:

$$F_\psi(y; C_{icap}) = \int_0^{+\infty} F_{L(h)}(x - y) \cdot f_{C(h;C_{icap})}(x) dx \quad (2)$$

With $y = 0$, the probability of a capacity shortage or a remaining capacity ψ less than or equal to zero is given by formula (3), where the pre-defined security level α (e.g. 1 hour in 10 years) may not be exceeded:

$$\widetilde{F}_\psi(0; C_{icap}) \leq \alpha \quad (3)$$

For a small number of identical generation units the probability function of the available generation capacity can be approximated by a binomial distribution. However, according to the de Moivre-Laplace theorem for probabilities not too close to zero or one

and a large number of generation units (suitable approximation from 30 units up) the available capacity can be modelled through a normal distribution (cf. de Moivre 1738). Using a first-order Taylor expansion around a reference capacity C_R , (3) can be approximated by:

$$\widetilde{F}_\psi(0, C_{icap}) \approx \widetilde{F}_\psi(0, C_R) + \left. \frac{\partial \widetilde{F}_\psi}{\partial C_{icap}} \right|_{0, C_R} (C_{icap} - C_R) \leq \alpha \quad (4)$$

$$\Leftrightarrow C_{icap} \geq C_R + \frac{\alpha - \widetilde{F}_\psi(0; C_R)}{\frac{\partial \widetilde{F}_\psi}{\partial C_{icap}}} \quad (5)$$

With costly capacity investments, the optimal capacity will satisfy the inequality (3) with equality. C_R ultimately specifies this minimum generation capacity to ensure the pre-defined security level and describes the capacity demand for a capacity market. Based on formula (5), the required minimum capacity C_R is then determined iteratively, so that $\widetilde{F}_\psi(0; C_R) = \alpha$ applies.

Figure 2a depicts a conceptual example of the proposed approach. Thereby the inverse cumulative distribution function of the power demand (black line) is convolved with the distribution of the available generation capacity (red line) for a given installed generation capacity of $C_{icap} = C_R = 97GW$ (dashed red line). Figure 2b zooms into Figure 2a and indicates the region where the available generation capacity is not sufficient (blue shape).

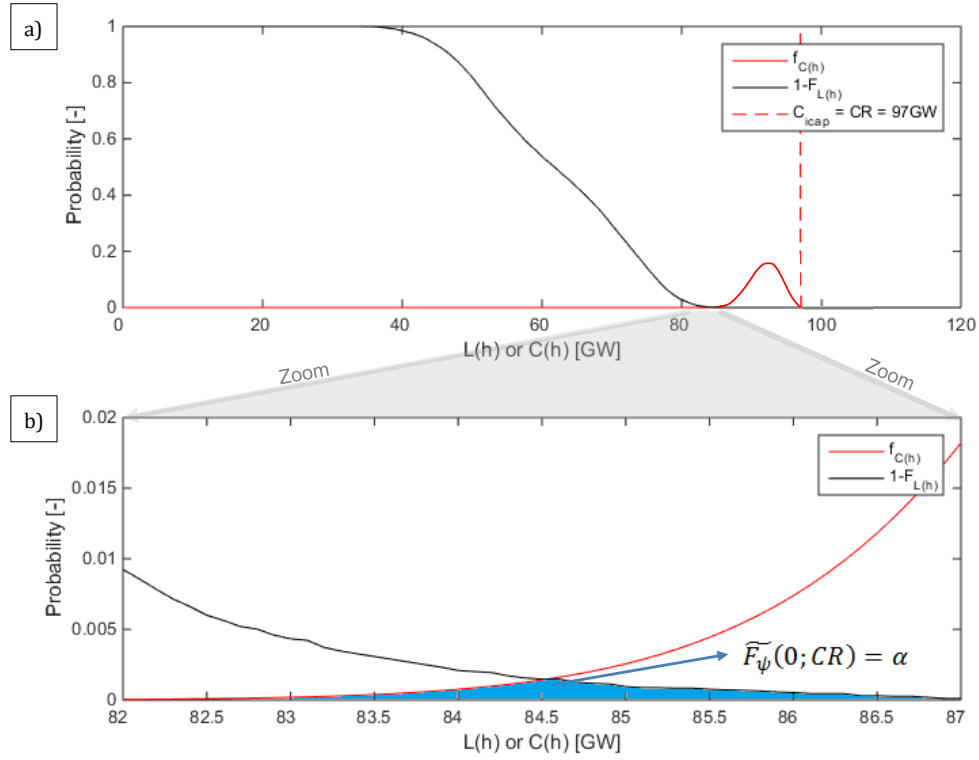


Figure 2: a) Conceptual example of the convolution approach, b) Zoom into a

2.3 Modelling of Capacity Markets

For the quantification of the economic effects of coordinated capacity markets, the European electricity market model (E2M2s) is used. It has been developed within the GreenNet-EU27 project and further elaborated in the SUPWIND project (cf. GreenNet-EU27 2009 and Supwind 2009). Assuming functioning competitive markets, market results are determined through optimization in the E2M2s model. That leads to an installation and operation of cost efficient power plants to cover demand. It is assumed that demand is price-inelastic. The model is formulated as a linear, stochastic problem with different regions and different time steps. The model is implemented in the General Algebraic Modelling System (GAMS).

The key variables of the model are generation, transmission and pumping quantities. During optimization, the yearly vector of variables that minimizes total cost subject to load restrictions is determined simultaneously. We consider electricity load profiles and heat load profiles. Moreover, reserve requirements for the provision of balancing services have to be covered. Technical limitations like minimum and maximum capacities, minimum and maximum down-times and start-up costs are considered in further

constraints of the power system. For details see Swider and Weber (2007), Spiecker et al. (2013) and Spiecker et al. (2014).

Load and RES fluctuations are captured in the model by analysing power supply and demand for eight typical days within one year. Thereby a working day and a non-working day are considered for every season. These typical days are again divided into seven time-steps in order to represent intraday fluctuations in demand and RES. The day starts with a 6 h time step, followed by a 5 h one. The third time-step represents the peak hour at noon. The remaining time of the day is split into 4 time-segments of equal length. This representation is chosen to represent on the one hand adequately the management of large-scale hydro reservoirs, which are typically used for seasonal storage. On the other hand the daily load patterns are required to describe the scheduling decisions for thermal power plants, including start-ups and operations at part load. In order to account for the intermittency of wind and solar infeeds and to overcome the limitations of typical time segments a recombining tree approach is applied (cf. Spiecker et al. 2013).

The use of transmission infrastructure is subject to restrictions considering the interconnections between market zones. A zonal representation of the European transmission grid is chosen due to computational reasons and the focus on generation adequacy in the longer run. Besides the optimal utilisation of transmission lines and power plants also investments in new power plants are determined endogenously. While in the short-run in most power systems sufficient generation capacity is available to meet demand, power plants might be shut down in the longer run due to a lack of fixed cost recovery through revenues from the energy-only market.

Hence, capacity markets are introduced which avoid the lack of energy supply in the long run and represent an additional income stream for power plants. To model capacity markets an additional constraint is introduced into the E2M2s model. It is assumed that only generation units which are not intermittent (i.e. excluding renewable energy sources like wind and solar) can offer firm capacity. Accordingly, capacity demand of a region $C_{R,r}$ can be covered by installed capacity of conventional thermal generation units $L_{r,u}$ and the minimum water inflow of run-of-river plants $\min(W_{r,u})$. Hydro reservoirs are expected to contribute with their installed capacity to firm capacity since profit oriented operation implies that they will usually adjust water usage in a way to deliver energy in times of scarcity. Correspondingly, the capacity market constraint can be described by:

$$\sum_{u \in U_{thermal,hydro-res}} L_{r,u} + \sum_{u \in U_{run-of-river}} \min(W_{r,u}) \geq C_{R,r} \quad (6)$$

The shadow price of the implemented constraint reflects the price on the capacity market. If this price is zero, either no new generation units are installed or new generation units can cover their capital costs by profits generated on electricity, heat and balancing markets.

2.4 Analysed Capacity Market Designs

As outlined in the introduction, in several European countries there are national plans for an implementation of capacity markets. As the EU Commission strives for an integration of national power systems, the implementation of unilateral national capacity markets is not expedient. A key issue for the analysed cases are therefore different levels of coordination. In order to investigate the effects of different levels of coordination, we first consider a reference case (**NATIONAL: NAT**) with independent national capacity markets. Thereby we assume that every country has to provide firm capacity and ensure system adequacy regardless of interconnections and generation capacities in neighbouring countries. Cross-border exchanges are however considered on the energy market in this case as in all further cases investigated.

In contrast, we model a Europe-wide capacity market (**EUROPE: EU**) with a joint provision of firm capacity. A Europe-wide mechanism might be difficult to realize given national energy policies and ambitions to achieve national self-sufficiency. However, this scenario is in line with the objective to achieve a single European electricity market, but requires a high coordination amongst all Member States.

The case **COORDINATED (COOR)** represents a reduced need for coordination. Here, a Europe-wide and common determination of capacity requirements is implemented. However, capacity markets are introduced at a national level. Compared with the reference case, the transnational coordination of capacity requirements allows taking advantage of some synergies that the EU case provides but without cross-border participation in the capacity markets and a full integration of national capacity markets.

To contrast these implementations with second-best alternatives we also assess possible drawbacks of uncoordinated capacity markets by considering two more cases. Under the scenario **ASYMMETRIC (ASYM)**, we investigate the latest national plans with an unilateral introduction of national capacity markets in France, United Kingdom, Ireland, Poland, Italy and Spain. In all cases capacity markets are introduced in 2020. To simplify, we assume centralised capacity auctions with capacity obligations. Under the assumption of full information this is equivalent to a decentralised capacity market as implemented e.g. in France. Following de Vries and Heijnen (2008), capacity obligations lead to more stable and efficient investment conditions and prices.

Figure 3 summarizes the simulated capacity market designs with regard to the degree of coordination and geographical coverage.

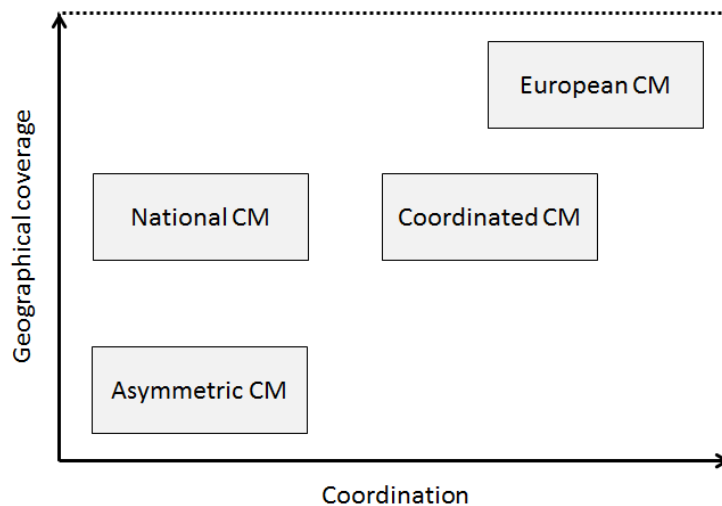


Figure 3: Simulated capacity markets

Furthermore, we model an **ENERGY-ONLY MARKET (EOM)** without consideration of capacity adequacy policies. In this case, profits and investments are basically driven by prices on the spot and balancing markets.

2.5 Data and Modelling Assumptions

The E2M2s model is applied to the previously described capacity market designs for the period from 2015 until 2050. Existing conventional generation capacities have been collected in the SUPWIND project (cf. Supwind 2009) and are further improved based on information of commercial power plant databases like Platts and several studies. The

existing capacities are adjusted by new capacities from already planned plants up to 2030 based on Entso-E (2014a) and Bundesnetzagentur (2016) (see also Figure 4).

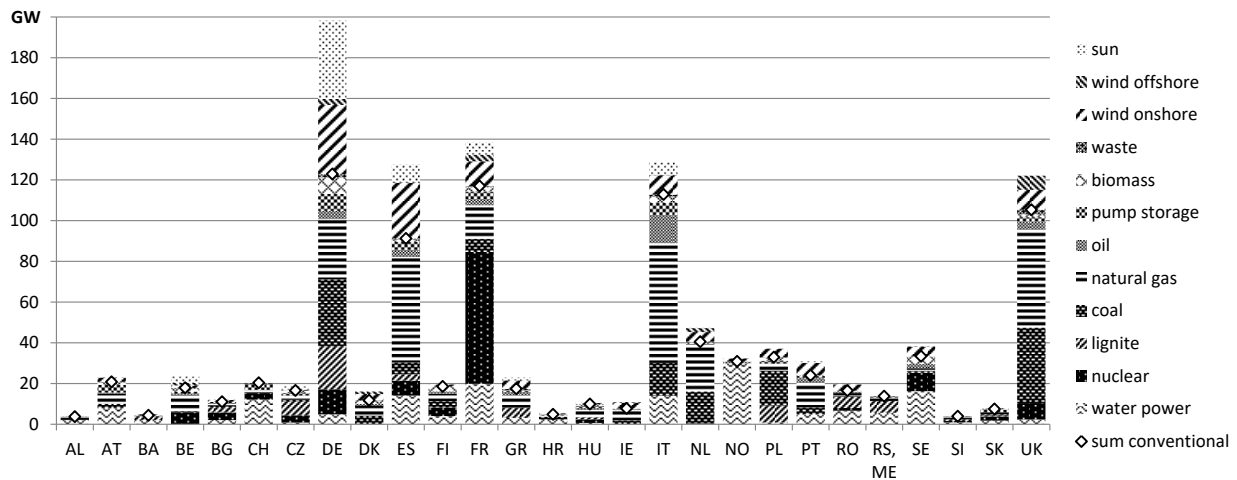


Figure 4: Installed generation capacities per country in 2015 (sum conventional: without wind onshore and offshore and sun)

All capacities are assumed to be decommissioned after a lifetime of 40 years in case of coal, lignite and gas plants with steam or combined cycle turbines. Gas turbines are assumed to be decommissioned after a lifetime of 35 years. Investment costs are based on European Commission (2013). Fuel prices are chosen in line with World Energy Outlook scenarios IEA (2015).

For renewable extension, estimations were made based on several studies (e.g. BMU 2012 and Entso-E 2014a). For the endogenous extension of wind, solar and biomass generation capacities, investment and variable costs are taken from Kost et al. (2013) and the European Commission (2013). Biomass units are dispatched according to their marginal costs. Wind and solar generation is modelled based on time series obtained from the European TSOs.

For the market model the reference electricity demand for each country is based on 2012 (cf. Entso-E 2016a and IEA 2014). In order to isolate the impacts of different capacity market designs, no change in electricity demand is assumed. The capacity demand is calculated using the above described power plant data and generation unavailabilities based on VGB (2014). Load profiles are taken from Entso-E (2016a). The results are described in section 3.1.

The E2M2s model covers the EU-27 countries and international cross-border flows are modelled using transmission capacities based on Entso-E (2016b). Thereby the expansion

of interconnection capacities is taken from the Ten Year Network Development Plan (TYNDP) (cf. Entso-E 2014b). Transmission capacities are assumed to be constant beyond 2030 given the ambitious expansion plans of the TYNDP.

The CO₂-price is modelled endogenously by specifying a EU-wide CO₂-reduction target for the electricity sector until 2050. Thereby a reduction of CO₂-emissions of 90% compared to 1990 is assumed.

3 Results and Discussion

3.1 Calculation of Capacity Requirements

According to step (II.) in Figure 1 the capacity requirements CR have to be predefined for modelling the capacity market designs. Based on ENTSO-E load data for three years, installed generation capacities and outage probabilities we calculate the CR for each country and Europe as a whole. Figure 5 depicts the computed capacity requirements for independent national capacity markets (NAT) using a reference security level of 1 hour in 10 years or $1.1416 \cdot 10^{-5}$. The sum of required firm capacity amounts to 727 GW.

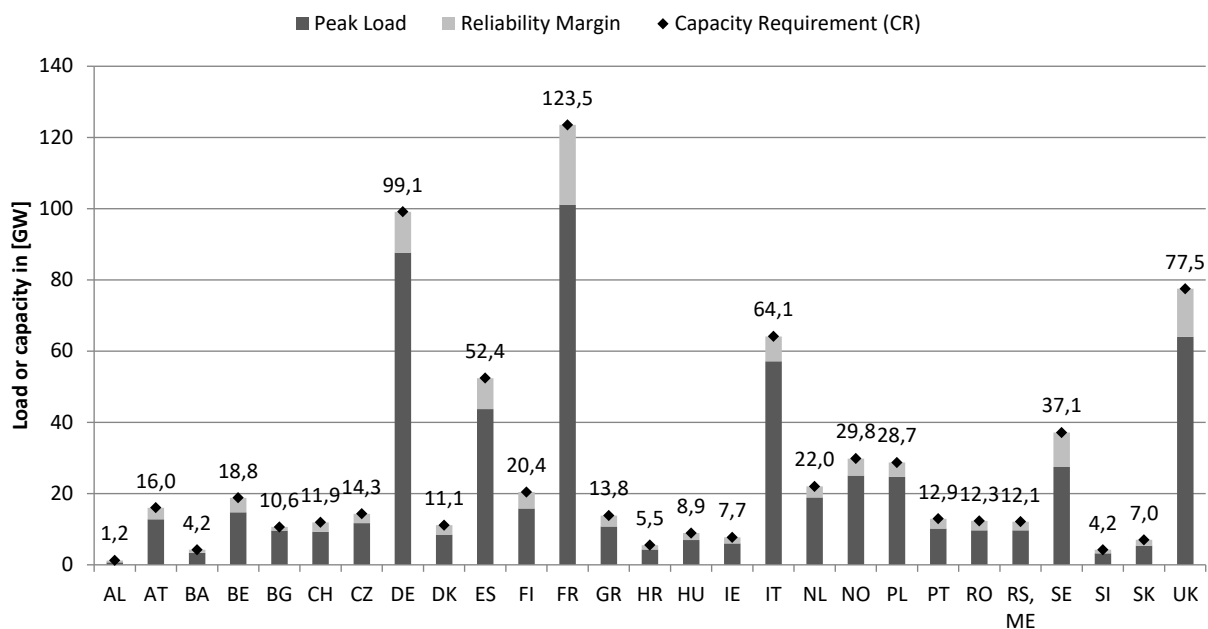


Figure 5: Capacity requirements and peak loads

The joint provision in case of a Europe-wide capacity market (EU) reduces the capacity requirements by roughly 10 % (661 GW instead of 727 GW). This can be attributed to two main effects. First, the simultaneous peak load of the European power system is about

30 GW lower than the sum of national peak loads due to compensatory effects. Second, the impact of unscheduled generation outages decreases with an increasing system scope due to the law of large numbers. Accordingly, capacity requirements are relatively higher in particular for small power systems and countries with a high share of nuclear plants due to their unit size. Notably the reliability margin in relation to peak load is 29.9 % on average for single countries with peak load below 15 GW whereas the average is 20.5% for those countries with peak load above 15 GW.

For the case COOR we adjust the national capacity requirements shown in Figure 5 by the proportion of the capacity requirement for a Europe-wide capacity market (EU) over the capacity requirements for national capacity markets (NAT):

$$C_R^{COOR} = C_R^{NAT} \cdot \frac{C_R^{EU}}{\sum C_R^{NAT}} = C_R^{NAT} \cdot 0.9183 \quad (7)$$

According to formula (7) the capacity requirement e.g. for Germany is reduced from 99.1 to 91.0 GW.

In the case ASYM, we consider an unilateral introduction of capacity markets in France, Poland, United Kingdom, Ireland, Greece, Italy and Spain. The capacity requirements are taken from Figure 5. For the remaining countries no capacity restriction is considered.

As no comprehensive historical information on hourly renewables generation for all European countries was publicly available, we do not consider the effects of intermittent renewables on capacity requirements in this paper. However, it should be noted that depending on the simultaneity of high power demand and high renewables generation, capacity requirements may be reduced. E.g. for Germany (where detailed data on hourly renewables generation is available) the capacity requirements can be decreased from 99.1 to 95.7 GW when taking renewables into account. The reduction of 3.4 GW can be mainly attributed to wind generation, since solar generation facilities usually are not available during typical high load situations in evening hours in winter.

3.2 Impacts on Power Markets

3.2.1 Generation Investments and Capacity Prices

The effects caused by the considered capacity market designs vary especially with the calculated capacity requirements. Together with a further increase of renewable generation and decreased operating hours of conventional plants, gas turbines are the cheapest option for additional firm capacity. Thus, investments in gas turbines are induced in case of NATIONAL capacity markets. In contrast, a EUROPE-wide capacity market results in lower additions of gas turbines (cf. Figure 6). In this case, firm capacity is shared between countries and until 2050 conventional capacity investment of about 100 GW is saved all over Europe. While this effect is mostly driven by the lower capacity requirements, we also observe a partial relocation of power plant investments. Due to advantages in terms of transportation and fuel costs and a more central location in the European power system, generation investments shift particularly from France to Germany, the Netherlands and Switzerland. Furthermore, we find increasing full load hours for existing (base load) generation capacities especially in Germany as building nuclear power plants in France is less profitable. To achieve the predefined CO₂ reduction target, the lower additions of gas and nuclear plants with relatively low CO₂-intensity are compensated by higher additions of wind offshore plants especially in 2030 (see right graph in Figure 6).

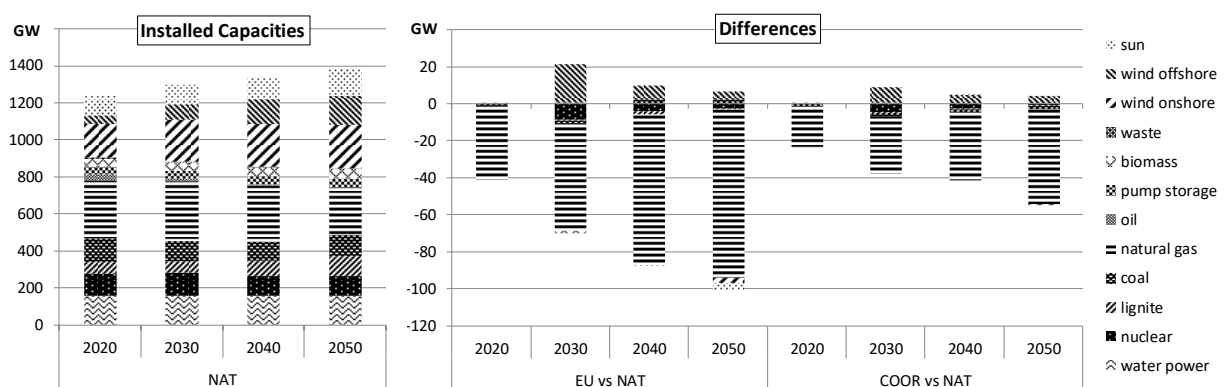


Figure 6: Comparison of generation investments – EU & COOR vs NAT

Comparing the cases NAT and COOR, it turns out that coordinated capacity markets reduce the needed power plant capacities. The difference is about 50 GW over the period 2020 to 2050 (cf. Figure 6). However, the coordinated determination of capacity

requirements combined with national capacity markets results in a higher addition of firm capacity compared to a Europe-wide capacity market. As no cross-border participation in the national capacity markets is considered in the case COOR, no relocation of plant investments occurs. Wind offshore plants are likewise built to compensate the lower additions of nuclear plants and to stick to the CO₂ reduction target. When capacity markets are introduced unilaterally (ASYM), lower investments in generation capacities occur in countries without capacity markets. These missing investments are partly compensated by higher gas turbine investments of countries that have capacity markets (see Figure 7). In the case EOM, the missing capacity remuneration schemes lead to lower additions of gas turbines and lower investments in base load capacities (nuclear and lignite). In both cases wind offshore plants are likewise built to compensate the lower additions of nuclear plants and to stick to the CO₂ reduction target.

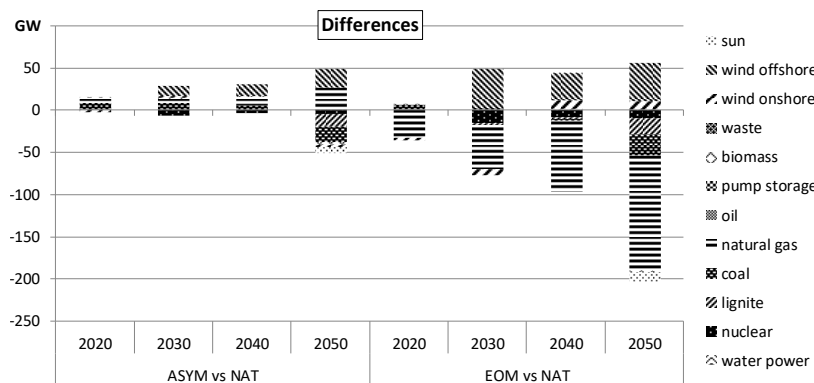


Figure 7: Comparison of generation investments – ASYM & EOM vs NAT

Further insights may be derived from the obtained capacity prices and capacity costs (cf. Figure 8). Investments in gas turbine plants are a consequence of their comparably small capital costs. In case of national capacity markets, gas turbine plants are thus chosen to fill the capacity gap and the capital costs of gas turbines are setting the capacity prices. As gas turbines are mainly built to provide additional firm capacity in hours with peak demand, the annual full load hours amount to only 200 at the maximum.

In case of a Europe-wide capacity market, lower capacity prices and costs are particularly observed in 2020 and 2030 as a result of lower capacity requirements and a joint provision of firm capacity. In these years only replacement investments in conventional base load capacity (partly driven by the nuclear phase-out in Germany) are observed and capacity prices are amounting to the fixed annual costs of gas turbine plants except

capital costs, i.e. cost for staff, insurance and cyclical maintenance. Existing peakers are sufficient to satisfy the capacity requirements in that case. Since their capital costs are sunk cost, they are not reflected in the capacity prices. With existing plants setting the price more frequently in the energy market, both their operating hours and their operating profits (for the inframarginal plants) increase compared to the NATIONAL case.

National capacity markets induce excess generation capacities and thus a more rapid and expensive modernisation of the existing power plant fleet. In contrast, a Europe-wide capacity market leads to a higher utilisation of existing plants and thus a higher capacity gap towards 2050, when the current power plant fleet reaches the end of its technical lifetime. As a consequence capacity prices rise in later years and capacity costs increase.

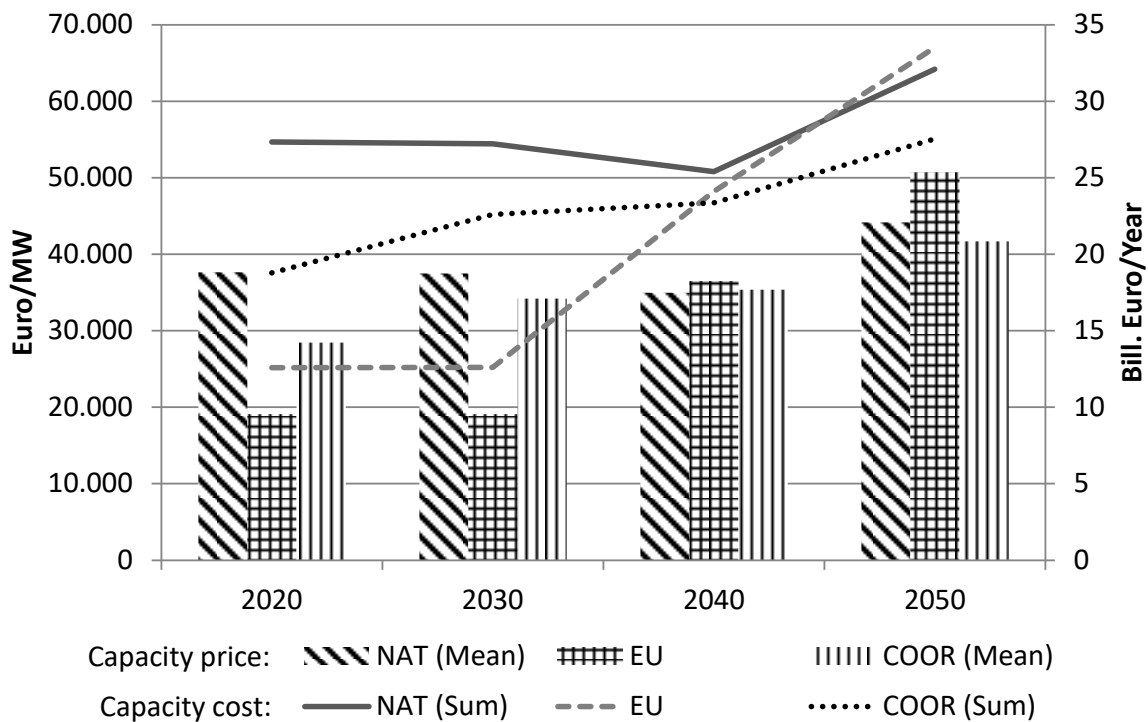


Figure 8: Average yearly capacity prices (bars - left axis) and costs (lines - right axis)

Similar effects can be observed when introducing coordinated capacity markets. However, in countries like France with extreme demand peaks during the winter period we find capacity prices amounting to the capital costs of new gas turbine plants, as firm capacity has to be provided on a national level and independently. In average this results in higher capacity costs compared to the Europe-wide capacity market especially in 2020 and 2030. Due to earlier replacement investments under the scenario COOR the need for reinvestments and retrofitting decreases towards 2050. Accordingly, lower capacity costs arise.

In all cases an increase of capacity prices or capacity costs until 2050 is observed, as renewable energy sources with small variable costs are becoming more important and consequently profits of conventional plants in the energy market decrease.

3.2.2 Spot Prices and System Costs

The geographical allocation of generation capacities varies with the considered capacity market designs. The resulting power plant mix in turn affects the merit order curves and thus the marginal prices in the (national) spot markets.

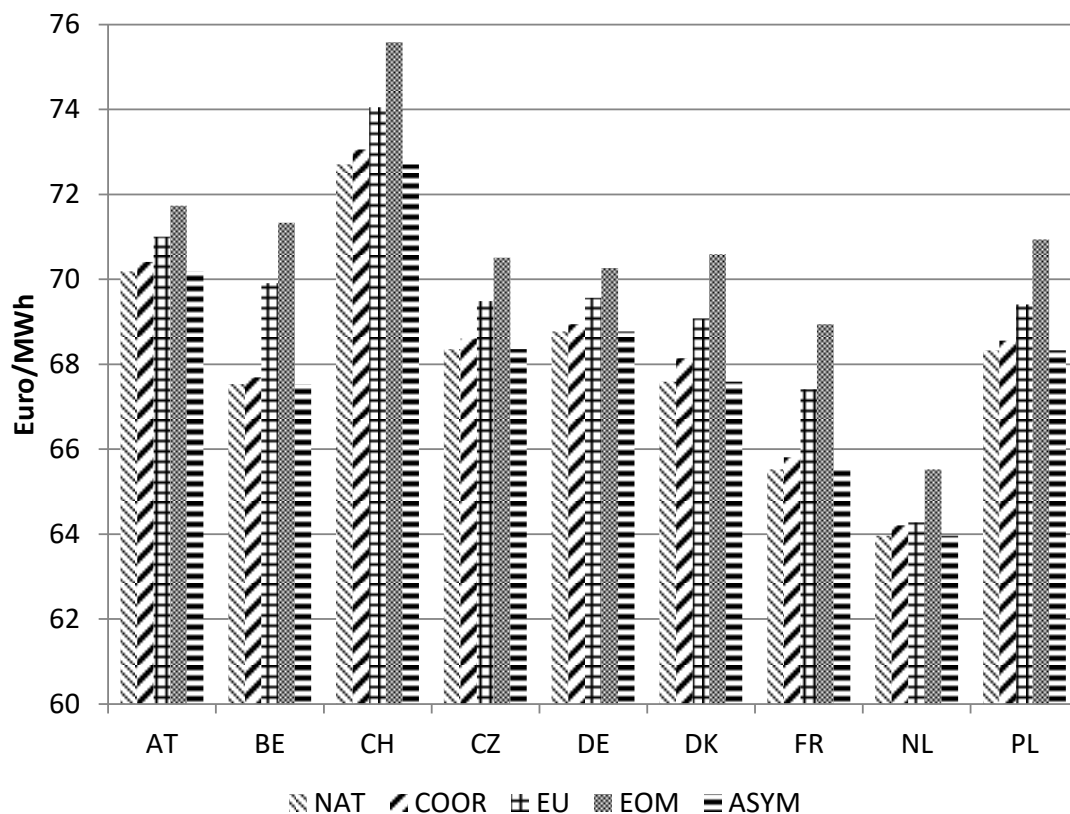


Figure 9: Average spot prices for selected countries in 2030

Figure 9 depicts the average spot prices for selected countries in 2030. The observed price effects can be explained by two key aspects. First, higher capacity requirements and corresponding additional capacities induce lower scarcity signals in the spot markets. In the case of national capacity markets lower peak prices are consequently observed given the earlier modernisation of the power plant fleet. Hence more efficient gas turbine plants with lower variable costs are price-setting. The lower generation investments under case EU result in a steeper end of the merit order curve and thus higher peak prices. Second, the considered market designs affect the profitability of base load

generation capacities and lead to a shift of the merit order curve. The smaller capacity requirements and lower capacity prices in case of a Europe-wide capacity market translate into a lower profitability and less addition of base load plants especially in France. As a consequence the (European) merit order curve shifts to the left compared to the scenario with national capacity markets. In hours with low or medium electricity demand, spot prices thus move up.

For the scenario EOM, where investments are basically driven by electricity prices, the simulations show the highest spot prices. A high standard deviation of hourly spot prices indicates a high volatility and increasing risks for market parties. In contrast, (coordinated) capacity market designs lead to a lower level and volatility of spot market prices. Thus, capacity markets not only provide reliable capacity payments but also reduce uncertainties regarding revenues from the spot markets (see Figure 10).

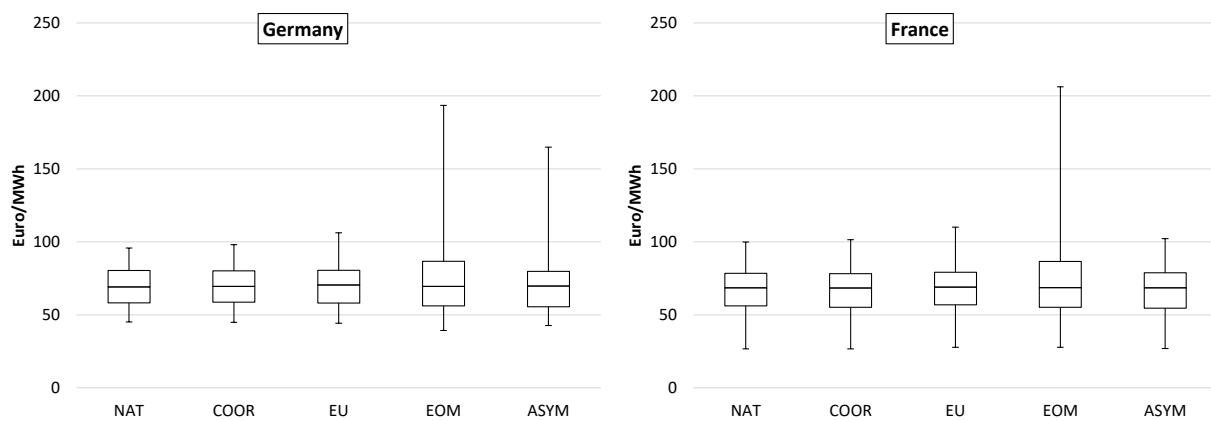


Figure 10: Boxplot spot prices Germany and France in 2030

In case of unilateral capacity markets (ASYM), the model results indicate adverse effects on spot prices and investment risks. In countries with capacity markets (amongst others France and Poland), low spot price levels are observed (see Figure 9) and investment uncertainties are reduced by capacity payments (see also Figure 10). Accordingly, spot price levels in interconnected countries decrease and countries without capacity markets free-ride. Depending on the simultaneity of peak demands and the available transmission capacities, additional firm capacity is thereby provided by countries that introduced capacity markets. This free riding effect is also observed by Tasios et al. (2014). In the long-term, unilateral capacity markets however compromise the efficiency of the energy-only market in neighbouring countries (cf. also Cepeda and Finon 2011). As a consequence of lower peak prices, investments in firm generation capacities shift to

countries that introduced capacity markets and security of supply decreases (see section 3.3).

In case of coordinated capacity markets CO₂, abatement costs increase, since less new gas and nuclear plants are built and the utilization of existing base load generation in particular lignite and coal plants increases. In order to comply with the European climate targets, higher CO₂ emissions of conventional plants are compensated by more offshore wind capacities (cf. section 3.2). In contrast national capacity markets associated with excess generation capacities and lower spot prices lead to a lower market value of intermittent renewables.

The impacts of introducing capacity markets on costs are shown in Table 1. Thereby, it has to be noted that the considered market designs and impacts on generation investments lead to different levels of security of supply (see also section 3.3). Under the reference scenario (NAT), the simulations show the highest system costs at the European level. The independent provision of firm capacity induces excess capacities and correspondingly high capacity costs, which cannot be compensated by the lower costs arising from the energy spot market. Coordinated capacity market designs (EU and COOR) lead to decreasing overall costs (up to -1.6% in 2030). This can be mainly attributed to efficiency gains induced by a joint provision of firm capacity, international synergies and a relocation of generation investments due to locational advantages.

Table 1: Impacts on system costs in Bill. Euro/Year

	REFERENCE	DIFFERENCES			
	NAT	EU	COOR	EOM	ASYM
2020	239,26	-2,66	-1,93	-3,74	-1,89
2030	246,12	-3,85	-2,41	-6,06	-3,55
2040	252,14	-4,95	-2,69	-7,96	-4,93
2050	263,38	-4,62	-3,03	-10,45	-5,48

Under the scenarios EOM and ASYM system costs are slightly lower. However, in both cases the level of security of supply is comparatively low (cf. section 3.3) and costs for load curtailment are not taken into account.

3.3 Impact on Security of Supply

As outlined in section 3.1 and 3.2, the considered capacity market designs lead to different capacity requirements and geographical allocations of generation investments. From a system operation perspective this might lead to differing levels of security of supply with regard to a national, regional or European perspective. Hence, based on the probabilistic sizing approach of capacity requirements and generation investments C_{icap}^{E2M2s} obtained from the market simulation a backward computation of the corresponding security level is performed for the simulation period 2030 (step IV. in Figure 1). The loss of load probability (LOLP) is a commonly used indicator for the evaluation of security of supply and describes the probability that a supply shortage might occur for a given period of time (cf. e.g. Calabrese 1947). Modifying equation 2, the LOLP measured in hours per year and the realized security level α can be computed as follows:

$$LOLP = \alpha \cdot 8.760h$$

$$\alpha = \widetilde{F}_{\psi}(0, C_{icap}^{E2M2s}) = \int_0^{+\infty} F_{L(h)}(x - y) \cdot f_{C(h; C_{icap}^{E2M2s})}(x) dx \quad (8)$$

As discussed in section 3.2, coordinated capacity markets lead to a geographical relocation of generation investments making some countries more and others less dependent on import capabilities and firm capacity abroad. An analysis of historical time series indicates that there is little likelihood of simultaneous electricity peak demand. Hence, the LOLP calculated for each country independently and without taking into account import capacities provides only a rough indicator of actual problems with security of supply. Yet an analysis of relative changes of LOLP between the considered capacity market designs will still provide valuable insights on their impacts on security of supply. The use of pure national LOLPs may also be justified by the fact that security of supply is challenging especially in extreme situations with simultaneous scarcity situations. Moreover, the analysis of LOLPs including imports and exports would ultimately require the modelling of joint distributions and the solution of optimisation problems for any possible joint realizations of remaining capacity ψ (cf. PLEF 2015). This is beyond the scope of the present study and therefore we focus on relative comparisons of pure national LOLPs.

While an increase of coordination allows taking advantage of compensatory effects and economic benefits, the national LOLPs and thus the threats to security of supply increase under the scenarios COOR and EU compared with national capacity markets (see Figure 11 and Figure 12). Accordingly, the LOLP is the lowest due to full national self-sufficiency and the induced excess generation capacities in the case of independent national capacity markets. Comparing EU and COOR we find that the absence of relocation of generation investments under the scenario COOR is beneficial in terms of security of supply and self-sufficiency in particular for countries at the periphery of Europe with otherwise higher costs and lower additions of firm capacity. Under the Europe-wide capacity market, especially Belgium and Denmark become highly dependent on import capabilities increasing their security of supply risk (for absolute national LOLPs see Figure 15 in the appendix).

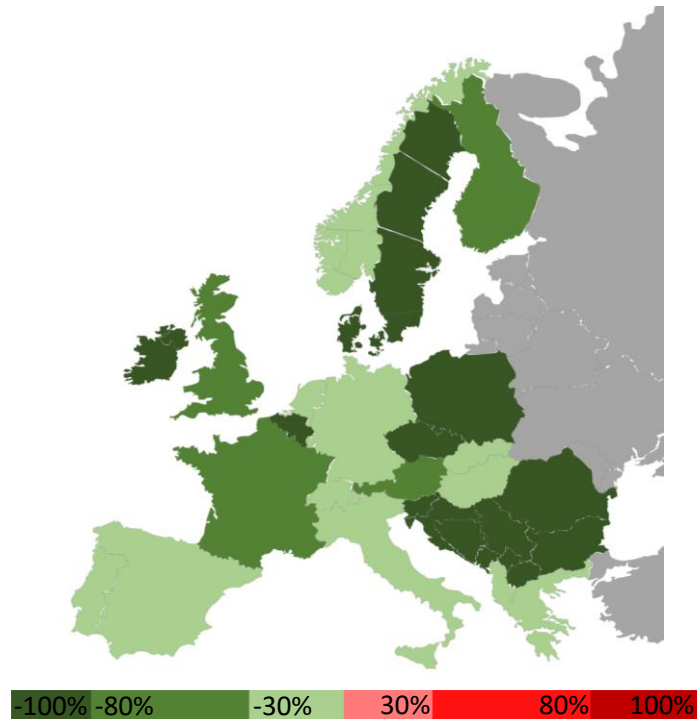


Figure 11: Relative change of LOLP for COOR vs EU

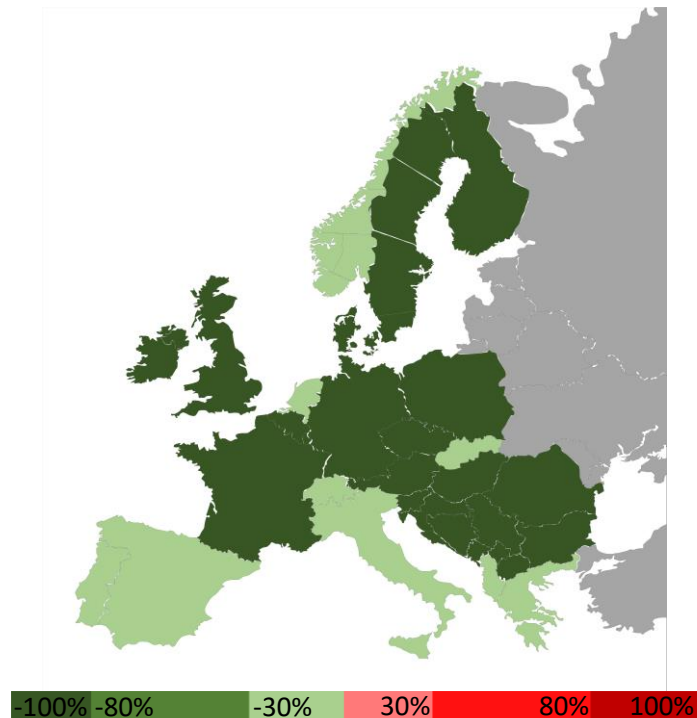


Figure 12: Relative change of LOLP for NAT vs EU

A comparison of the cases ASYM and EOM illustrates the adverse effects regarding the free-riding problem and security of supply. In general the spot markets would allocate available transmission capacity to countries with a supply shortage in the case of non-simultaneous scarcity. In particular Germany would become a net-importer and free-ride

on capacity markets in neighbouring countries in the short-term. However, in the long-term inadequate investment incentives in countries without capacity mechanisms would push domestic generators out of the market. In combination with scarce import capacity, the LOLP would consequently increase. According to Figure 13, the unilateral introduction of capacity markets in France, United Kingdom, Ireland, Poland, Italy and Spain puts security of supply at risk in the surrounding countries.

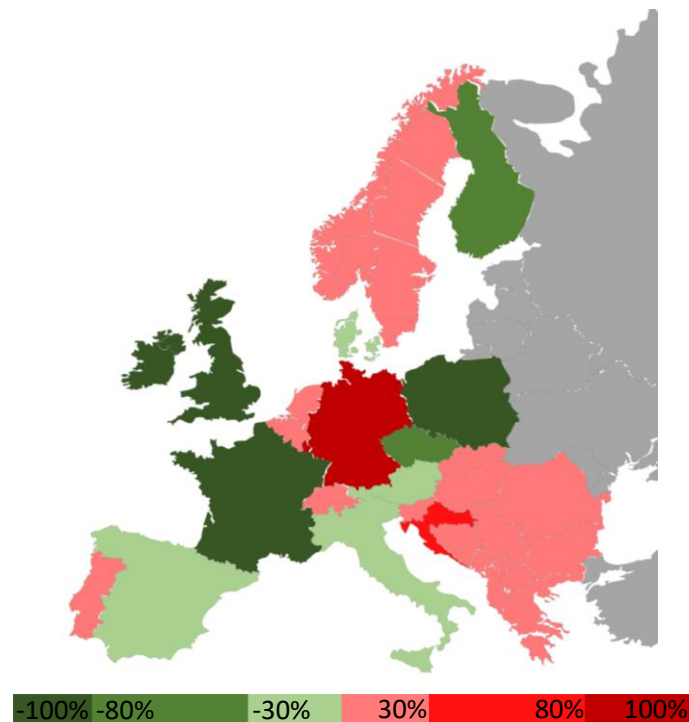


Figure 13: Relative change of LOLP for ASYM vs EOM

Under a framework without capacity markets, investment decisions are based on revenues gained in the energy-only market which are subject to fundamental risks like the development of renewable capacities, electricity demand, CO₂ and fuel-prices as well as regulatory uncertainties. The expected future electricity demand (and renewables infeed) is also relevant for the determination of capacity requirements (cf. section 2.2). Consequently, an underestimation of the realised electricity demand will lead to an underestimation of capacity requirements in the case of capacity markets. This will lead to scarce generation capacity and supply shortages exceeding the tolerated security level. In Figure 14, we analyse the impact of a deviation of 3% of the expected electricity demand on the average LOLP for the considered market designs in 2030. For the cases ASYM and EOM, a considerable increase of LOLP is found. Under the scenario ASYM,

the higher LOLP is notably found in countries without capacity markets, where domestic generators are pushed out of the market.

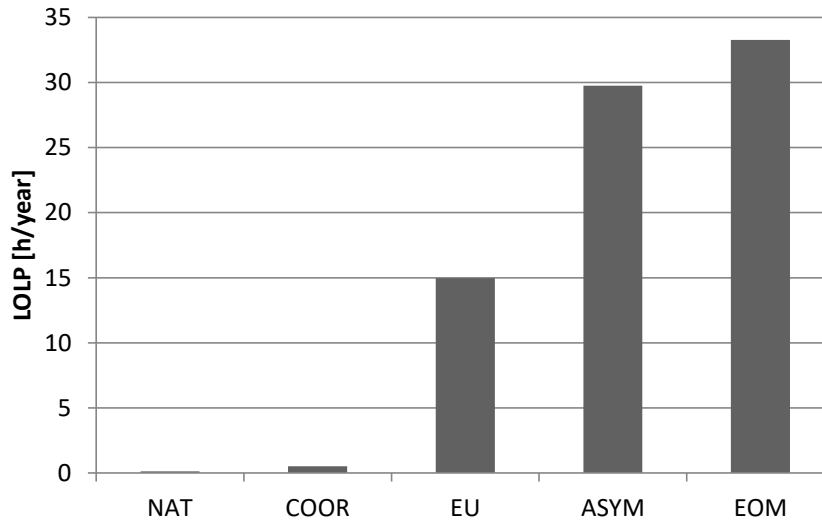


Figure 14: Average change of LOLP if load is 3% higher than expected

In the case of a Europe-wide capacity market, the LOLP increases in particular in countries that face lower additions of generation capacity due to the geographical relocation of generation investments (i.e. France). Due to the absence of relocation of generation investments under the scenario COOR, a lower increase of LOLP is observed. Only under independent national capacity markets, robustness in case of a load deviation of 3% and simultaneous scarcity is ensured (increase of LOLP by only 0.03 h/a).

4 Conclusion

In this article we present a probabilistic approach for the determination of capacity requirements and analyse the long-term development of the European power market considering different capacity market designs. The analysis indicates that coordinated capacity markets lead to lower capacity requirements compared to independent national capacity markets. Under a Europe-wide capacity market, the joint provision of firm capacity reduces the capacity requirements by roughly 10% (661 GW instead of 727 GW). Following the model results, we come to the conclusion that coordinated capacity markets result in efficiency gains of up to 5 billion Euros per year. Besides lower capacity requirements, the reduction in system costs is also a consequence of a geographical relocation of generation investments to regions with lower fuel prices and a higher utilization of existing (base load) generation units. In terms of security of supply, it is

however shown that coordinated capacity markets with a joint provision of firm capacity lead to a higher dependency on import capabilities especially for Belgium and Denmark. Accordingly, the level of security of supply and the self-sufficiency will decrease in the case of simultaneous scarcity.

The simulations indicate that asymmetric capacity markets induce adverse cost effects and a distortion of generation investments. It is shown that unilateral capacity markets have strong negative effects on the energy markets in interconnected countries. While countries without capacity markets free-ride on countries with capacity markets in the short-term, the missing money problem increases in energy-only markets in the long run and domestic generators are pushed out of the market. Consequently, generation investments shift to countries with reliability mechanisms and security of supply in countries without a capacity market decreases.

Finally, it has to be noted that the benefits of coordinated capacity markets basically depend on the structure and potential cross-border synergies of the considered power system. As an adequate determination of capacity requirements is of major importance, the proposed multiregional probabilistic approach should be extended to account for grid constraints. Moreover, uncertainty with respect to future developments should be incorporated explicitly since deviations may have a considerable negative impact on security of supply counteracting any economic benefit. Further research should therefore focus on the performance of capacity mechanisms under uncertainty in interconnected power systems.

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Appendix

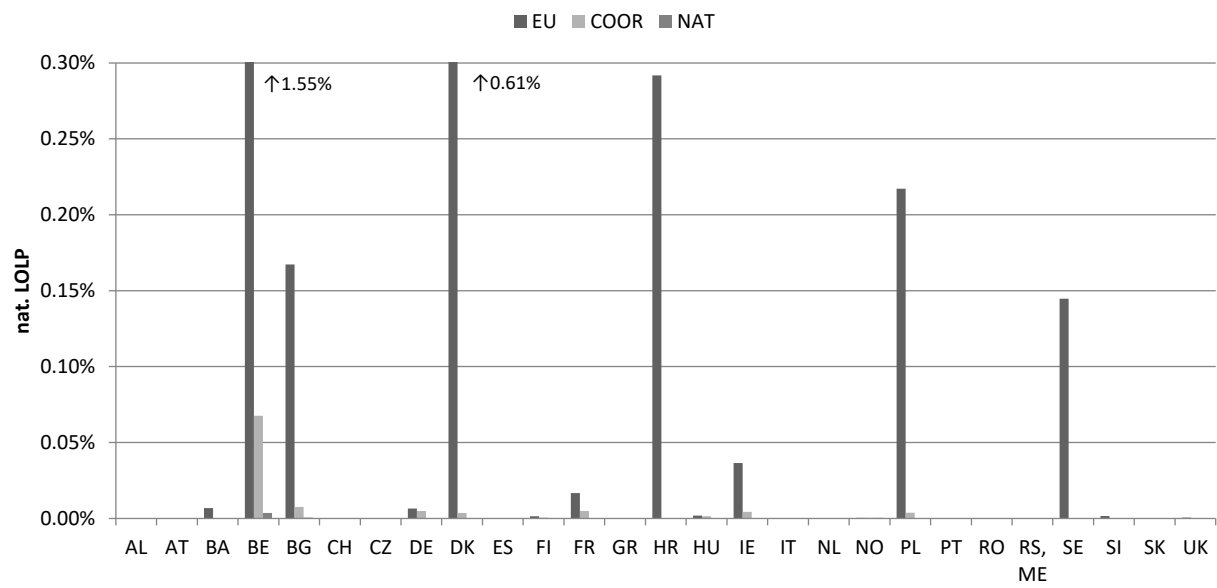


Figure 15: National LOLPs for the cases EU, COOR and NAT

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