INTEGRATING INTERMITTENT RENEWABLES:

INTERACTION OF ELECTRICITY CAPACITY MARKETS AND INTERCONNECTION

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Abstract

Scaling up intermittent renewable energies is critical to mitigating climate change. However, their economic structure and intermittency poses several challenges. While pertinent responses such as interconnection and capacity markets have been studied extensively on their own, their interaction has received little attention in the literature. Especially the influence of intermittent renewables and stakeholder opinions has not been considered. I contribute to closing this gap, using theoretical economic analysis, semi-structured interviews and empirically-grounded electricity-modelling to examine effects on energy security, welfare and carbon emissions based on a case study of France and Germany. I find that benefits from increased interconnection and capacity markets outweigh their costs, however, resulting in redistribution effects primarily within countries. Moreover, to some extent markets with significant shares of intermittent renewables might benefit from neighbouring capacity markets through interconnection. Finally, polycentric governance is suggested as appropriate form of governance due to different rationales of introducing capacity mechanisms.

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1. Introduction

1.1. Relevance and justification

Scaling up renewable energy is absolutely critical to solving climate change. Scenarios that both leave 'a safe operating space for humanity' (Rockström et al. 2009) and are economically plausible require a significant increase in renewable energy, especially wind and solar energy (Nauclér & Enkvist 2009; International Energy Agency 2010; Edenhofer et al. 2011).

Resolving challenges regarding intermittency and economic structure of these renewables is critical to their grid integration and scale up. Due to the flexible and often unpredictable generation of solar and wind, highly flexible energy systems are required. Additionally, due to their economic structure with effectively zero marginal costs, they might remove incentives for sufficient backup generation investment and endanger security of supply.

Thus, the interconnection of electricity markets and the design of mechanisms to ensure security of supply are central to solving these challenges. A variety of solutions have been suggested for solving the flexibility issue, including incentivising storage, demand-side response, flexible capacity and (cross-border) interconnectors (Edenhofer et al. 2011). Moreover, a myriad of capacity mechanisms have been suggested to ensure short-term security of supply and long-term generation adequacy.

In the European Union, the expansion of electricity cross-border interconnectors is a headline goal of the Energy Union, among others for integrating renewable energies. Every Member State should be able to export 10% of its generation capacity by 2020, the goal of 15% by 2030 is currently being discussed. Interconnection not only enables the integration of low-carbon and intermittent renewables, but also allegedly contributes to the other two dimensions of the energy policy trilemma (European Commission 2015b).

While these efforts represent major steps of physically integrating European energy systems, energy policy is still largely at the discretion of its Member States. Among others, market design is primarily a concern of national energy policy and many European countries have been discussing or already implementing different capacity remuneration mechanisms (CRM) to ensure generation adequacy. However, given increasing interconnection, the European Commission has already raised concerns about the lack of harmonisation of different CRMs which has the potential to distort cross-border trade and impede the realisation of the European Internal Electricity Market (European Commission 2013b) and thus might ultimately also hamper the integration of intermittent renewables. I define interconnection as the physical grid connecting electricity markets of two countries and consider a wide definition of capacity markets, including forward capacity auctions and decentral obligations, while focusing on the latter for the case study.

The effects of both capacity markets and increased cross-border interconnection have been studied extensively on their own, however, their interaction has received very little attention in the academic literature. While this topic may seem somewhat obscure and academic, it is absolutely central to the reduction of greenhouse gas emissions and climate change mitigation. It is thus an important area of research on its own but also a wider case study on polycentric governance of energy systems (Ostrom 2010; Goldthau 2014).

1.2. Aims, research questions and organisation

On the broadest scale, this dissertation aims to advance our understanding of the necessity of coordinated and homogenised energy policies across different countries. More specifically, it investigates the interaction of cross-border interconnection and capacity markets given intermittent renewables, and precisely the effects of increased interconnection capacity between energy-only and energy-and-capacity markets on security of supply, welfare and carbon emissions. Due to the current debate about the introduction of a capacity market in France as well as the large penetration of intermittent renewables in the German electricity market, I will primarily focus on the French-German case using mixed methods research.

To achieve aforementioned aims and objectives, the specific research questions that my dissertation will address are: To what extent can increased interconnection expansion be combined with the introduction of capacity markets? (a) To what degree are interconnection and capacity markets substitutes? (b) To what degree does interconnection necessitate a common solution with respect to market design? (c) What are the effects of increased interconnection and a unilateral introduction of capacity markets on both markets, especially given substantial shares of intermittent generation? Figure 1 presents the research questions as well as the analyses in which they will be addressed.

Research Questions	Methods
To what extent can increased interconnection expansion be combined with the introduction of capacity markets?	Theoretical economic analysis Semi-structured interviews Electricity system modelling
(a) To what degree are interconnection and capacity markets substitutes?	Theoretical economic analysis Electricity system modelling
(b) To what degree does interconnection necessitate a common solution with respect to market design?	Semi-structured interviews Electricity system modelling
(c) What are the effects of increased interconnection and a unilateral introduction of capacity markets on both markets, especially given substantial shares of intermittent generation?	Electricity system modelling Semi-structured interviews

Figure 1 Research Questions and Methods

This dissertation is structured as follows. Section 2 gives an overview of the related literature and describes the electricity markets in Germany and France. Section 3 specifies and justifies the mixed methods approach while section 4 presents the results of theoretical economic analysis, semi-structured interviews and empirically grounded electricity system modelling as. Broader implications and limitations are presented before concluding in section 5.

2. Literature Review

To deliver the context of the debate around increased interconnection and capacity mechanisms in the EU, this chapter first outlines the governance of energy systems in the EU, before reviewing the literature on the problem of the flexibility and capacity issue concerning intermittent renewables. Focusing on interconnection and capacity mechanisms as possible responses, the literature on these topics as well as their interaction is synthesised and critically analysed. Finally, the electricity systems of Germany and France are shortly described.

2.1. European energy market integration and national policy

2.1.1. The Internal Energy Market and the Energy Union

Energy has been one of the primary areas of policy of the European Union since its foundation. Already in the 1980, the formation of an Internal Energy Market consisting of a convergence of rules and expansion of physical grid interconnectors was envisaged (European Commission 1988). However, concrete steps towards such a fully integrated European energy market were only taken in 2009, with the Third Energy Package, more concretely by the Directive 2009/72/EC that defines “common rules for the internal electricity market” (European Parliament and Council 2009, p.1). The package promotes, among others, better cross-border collaboration among member states, specifically, the directive formulates operational, regulatory and technical rules for interconnectors. These efforts towards an internal energy market with cross-border interconnection as the “internal market’s hardware” (European Commission 2015a, p.8) are intensified as part of the “Energy Union” in 2015. Interconnectors have specifically be seen as an effective method of addressing concerns about security of supply as a result of the increasing integration of intermittent renewable energy supply into the electricity grid (Puka & Szulecki 2014).

2.1.2. Energy policy: responsibility of the Member States?

While the move towards an internal electricity market has led to an increased integration of European electricity markets (IEA 2014), energy policy is still largely a concern of the Member States with some notable exceptions (Strunz et al. 2014; Tews 2015; Szarka 2016). Although the Lisbon Treaty defines energy as a shared competence between Member States and the European Union, the general structure of the energy supply, including the security of supply, is specified as still a competence of the Member States. This might lead to a governance dilemma (Tews 2015). On the one hand, the internal energy market, including cross-border interconnection expansion, aims at harmonising European energy markets and is primarily a matter of the European Union. On the other hand, issues relating to the energy mix, e.g. decisions to incentivise specific (renewable) energy sources, or measures to increase the security of supply, e.g. capacity mechanisms are primarily at the discretion of the Member States. As a result, the integration of low carbon and intermittent electricity sources into the grid requires multi-level or even polycentric governance in the European Union (Calliess & Hey 2013; Goldthau 2014).

2.2. Integrating intermittent renewables into the electricity system

While the costs of intermittent renewable energy, notably solar and wind, have decreased rapidly in the last years (IRENA 2014), the largest challenges of integrating them into the electricity system relate to their intermittency and economic structure (e.g. Henriot & Glachant 2013).

2.2.1. The flexibility issue

The issue: intermittent generation

The first challenge of integrating intermittent renewable energy is its variable generation. Balancing electricity demand with supply is already an issue in many countries (e.g. RTE 2015) and further integration of intermittent renewables into the grid enhances this problem. In general, there are four – although not mutually exclusive – options to integrate intermittent renewables into the electricity grid. These comprise (1) flexible supply, e.g. curtailment, (2) flexible demand, e.g. demand side response, (3) balancing over time, e.g. battery storage and (4) balancing over space, e.g. cross-border electricity interconnectors (Edenhofer et al. 2011). Due to its alleged characteristic of positively contributing towards all three dimensions of the energy policy trilemma, the expansion of electricity cross-border interconnectors has been stressed to be a pivotal step towards the internal European energy market and the integration of intermittent renewables (European Commission 2015a).

A response: Interconnection expansion

In order to steer, monitor and assess the expansion of cross-border interconnectors in 2002, the European Union stipulated that every member state should be able to export at least 10%

of its capacity by 2005 (Jacottet 2012). However, progress has been limited and in reaction the 10% target was reiterated with the time horizon over which this should happen being adjusted several times, recently targeting 2020 (European Commission 2015a). As part of the Energy Union, it is currently discussed whether the target should be set to 15% interconnection capacity by 2030 (European Commission 2015b). However, in spite of the increased effort on the European level to promote the expansion of interconnector capacity, progress so far has been limited and many member states still fall significantly short of the 10% and 15% objectives (see Figure 2) – an issue described as the 'grid-lock' problem (Puka & Szulecki 2014, p.125). In order to accelerate the pace of interconnection expansion a number of Projects of Common Interests (PCIs) were identified to enhance the build-out of a trans-European grid network.

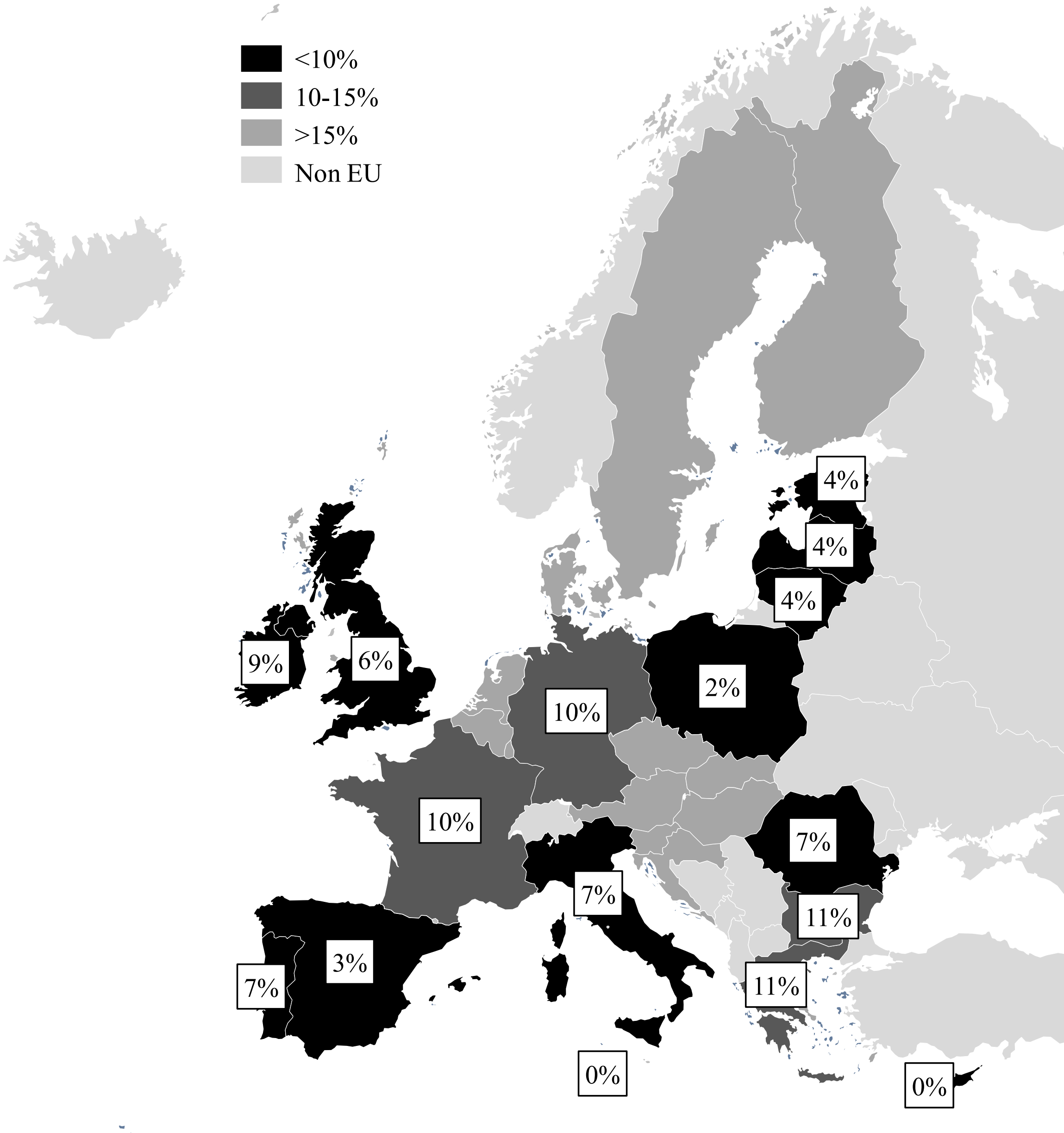

Figure 2 Interconnection capacity as percentage of generation capacity (based on European Commission 2015b)

The literature primarily states benefits of increased interconnection, effectively contributing to all three pillars of the energy policy trilemma, however with several notable caveats.

Affordability

Most of the benefits from increased interconnection are ascribed to efficiency gains resulting from increased competition and trade (Nooij 2011). Interconnectors drive down mark-ups over marginal costs resulting from market power (Küpper et al. 2009) as well as enable an increased utilisation of low cost generation (Billette de Villemeur & Pineau 2010), thus decreasing overall average wholesale prices. While there seems to be some consensus that interconnectors have such effects for the overall electricity system (e.g. Nepal & Jamasb 2012), for individual countries, wholesale prices might increase due to an interconnector (Turvey 2006; Parisio & Bosco 2008), resulting in questions regarding distributional fairness. Although these issues arise, as such, interconnectors are seen to be generally welfare enhancing, if welfare increases are larger than investment cost (Valeri 2009). Lynch et al. (2012) stress, based on their assessment of Northern Europe, that these benefits are only larger than interconnection investment costs for scenarios of higher shares of renewable generation.

Energy security

It is often assumed that increased interconnection enhances energy security, primarily security of supply (European Commission 2015b), although it is contested in the literature. Generally, increased interconnection decreases the need for reserve capacity in national electricity markets (Valeri 2009). However, there is much debate about whether interconnection enhances security of supply during peak demand periods. First, Worthington et al. (2005) argue that interconnection leads to spatial averaging during peak times. Second, Jerko et al. (2004) find no difference of interconnectors enhancing spatial averaging during peak compared to off-peak periods. Third, based on data from the UK, Germany, France and the Netherlands, Bunn & Gianfreda (2010) find that during times of high seasonal demand and peaks, interconnectors provide least benefits from spatial averaging. This would imply that during times of potential electricity grid blackouts, interconnectors are least able to balance supply and demand over space. As a result, only to some extent, might interconnectors be able to balance increased supply volatility from intermittent renewable energy.

Other studies specify the contingencies under which interconnection increases the security of supply. Brancucci et al. (2013) find that the planned additional cross-border interconnection capacity in Europe will not significantly increase security of supply, however it will be needed in case of increased supply from intermittent renewable energy. Furthermore, Wilson et al (2010) suggest that the ability of interconnectors to enhance the resilience of the energy system depends on the energy mix across the connected regions. DECC (2013) report that more interconnection leads to an increased security of supply using two stress test scenarios. Although low wind supply and high demand situations might often be correlated across European markets, plant outages are not, resulting in significant enhancements of energy security through interconnectors. Cepeda et al. (2009) conclude that interconnection improves long-term security of supply, i.e. generation adequacy, up to a certain level, which depends on the symmetry of technologies, market size and adequacy criteria of interconnected markets. In conclusion, the assumed positive effect of increased interconnectors seems to depend on several contingencies, including the energy mix, market size and security of supply standards.

Sustainability

Electricity interconnectors have been identified as one of the main possibilities of integrating intermittent renewable energy into the electricity grid, thus contributing to a decarbonisation of the energy system. In a 100% renewable scenario, Steinke et al. (2013) find that backup capacity can be decreased from 40% to 19% through increased interconnection. Similarly, Becker et al. (2014) model that quadrupling current European interconnection reduced backup requirements by 33%. In contrast, (Mezősi et al. 2016) suggest that carbon emissions might rise after the fulfilment of the 10% interconnection target due to the increase of cheap coal- and lignite based electricity production in Germany, Poland and the Czech Republic that is exported to neighbouring countries. While these results point towards some caveats of increased interconnection, they underline the necessity to increase low carbon electricity production at the same time.

While interconnection is able to contribute to the integration of intermittent low-carbon technologies, there are additional environmental and social benefits and costs, or more broadly impacts, during construction and operation of interconnector projects (UN 2006). As a result, environmental impact assessments (EIAs) are a legal requirement for the construction of every interconnector within EU member states. For example, past EIAs of interconnector projects include, among others, impacts on ecology, land use, geology, hydrology, noise and air quality and develop several mitigation plans (ScottishPower 1997; NationalGrid 2014). However, while EIAs assess environmental impacts of interconnector projects, cost-benefit analyses usually do not consider them explicitly in their calculation, although some attempts to qualitatively describe them seem to be made (Nooij 2011). For the East-West interconnector, the cost-benefit analysis even overlooks environmental costs completely, only mentioning environmental benefits, e.g. reduced wind curtailment (EirGrid 2008). However, there seems to be a general consensus that the inclusion of an environmental impact assessment usually minimises local negative environmental impacts (Marshall 2005). Regarding social sustainability, public opposition for amenity reasons and "not in my backyard issues" signals negative effects of increased interconnection, leading to an increased consideration of more expensive underground cables (Battaglini & Lilliestam 2006). In conclusion, electricity interconnectors contribute to the integration of renewable energy into the grid, enabling the prevention of dangerous anthropogenic climate change, while resulting in some other negative environmental and social impacts.

In conclusion, despite several notable caveats, cross-border electricity interconnectors contribute to all three pillars of the energy policy trilemma, while enabling the grid integration of intermittent renewables.

2.2.2. The capacity issue

The issue: Recovering generator fix costs

The second challenge for the integration of intermittent renewable energy into the grid is incentivising adequate investments in back-up capacity with an increasing share of close to zero marginal cost renewable energies.

In theory, liberalised electricity markets incentivise short-term economic efficiency and long-run generation capacity adequacy (Caramanis 1982; Schweppe et al. 1988; Stoft 2002). In these competitive energy-only markets, electricity suppliers bid their short-term marginal costs, resulting in a typical merit order supply curve from low marginal cost renewables, nuclear plants and coal to high cost gas. The hourly electricity market clearing price arrives at the marginal cost of the last generator, provided that demand does not exceed dispatchable capacity. Generation plants thus directly recover their variable costs. They also recover their fixed costs through inframarginal rents, the area between marginal costs and the market clearing price as well as through scarcity rents. The latter arise in a small number of hours of scarcity situations per year when demand is larger than dispatchable capacity and demand is curtailed at the value of lost load or the maximum price as set by the regulator. These scarcity rents are an important source of revenue for plants that are only dispatched a few times a year during peak periods to recover fixed costs. As a result, liberalised electricity markets should generally be able to provide sufficient incentives for capacity adequacy (Oren 2005; Hogan 2005). For an overview of the fundamental economics refer to Figure 3.

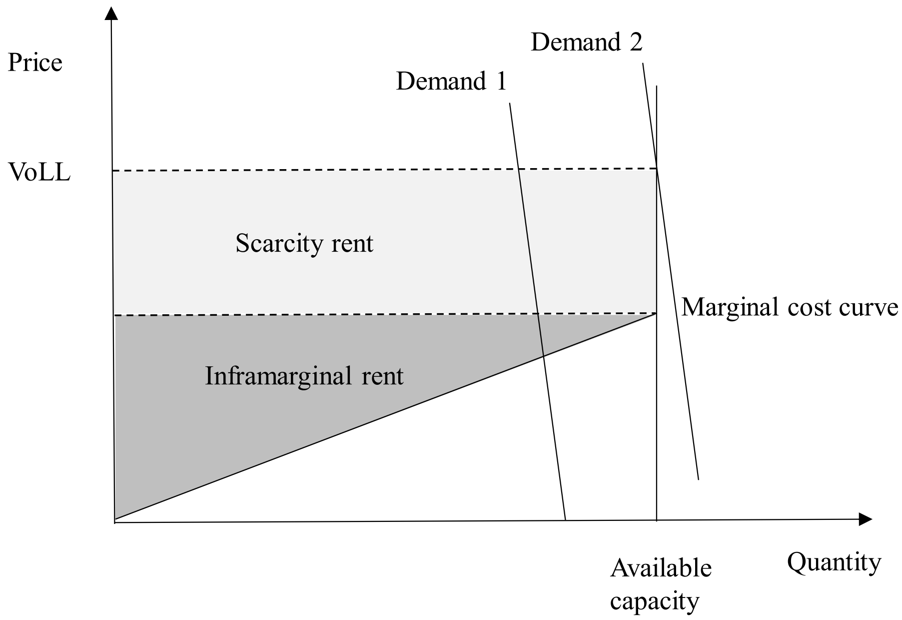

Figure 3 Fix cost recovery in the wholesale market (based on Joskow 2006)

However, several scholars have argued that energy-only markets exhibit several market failures, suggesting that they are unable to guarantee capacity adequacy and security of supply at all times (Bidwell & Henney 2004; Cramton & Stoft 2005; Joskow 2007; Joskow & Tirole 2007; de Vries & Heijnen 2008; Batlle & Pérez-Arriaga 2008; Finon & Pignon 2008; Cramton & Ockenfels 2012; Olsina et al. 2014). First, the regulator might have to cap scarcity prices in order to prevent market-power abuse in times of scarce supply. Such capped scarcity prices may make it difficult for energy producers to recover fixed costs thus causing a "missing money problem" (Joskow 2008, p.159). Second, while demand and supply are to be balanced in real time, the increase of capacity takes a number of years. Given that investors are risk-averse, new capacity investments usually are delayed and only realised when they are sure to be profitable (Dixit & Pindyck 1994; Neuhoff & De Vries 2004; Hary et al. 2016), posing risks to capacity adequacy. Third, the increasing share of renewables might cause a missing money or even missing capacity problem. Most renewable energies, notably solar and wind, have zero marginal costs and are often subsidised by feed-in-tariffs, thus representing entirely "price-inelastic demand" (Cramton et al. 2013, p.1). As a result the merit order is shifted rightward, leading to an overall decrease in electricity prices (Tveten et al. 2013). As a result, back-up plants receive insufficient revenues to cover their fixed costs, leading to their decommissioning and limited investment incentives for new backup plants. This limited investment in backup plants puts the provision of security of supply at risk. The intermittency of most renewable energy technologies additionally enhances this problem as these rely especially on additional backup capacity (Steinke et al. 2013). As concerns about energy security are frequently prioritised over sustainability (e.g. Proedrou 2016), the provision of inadequate backup security during the transition to a low-carbon energy system, thus might inhibit the legitimacy of the project in the first place.

A response: Capacity remuneration mechanisms

As a result, a myriad of capacity remuneration mechanisms have been suggested both by policy makers and the literature. They have been discussed or have already been implemented in a number of European countries. These comprise of capacity markets, capacity payments, strategic reserves and reliability options. For a detailed overview of these mechanisms refer to European Commission (2016). What they all have in common is to ensure the short-run security of supply and long-run adequacy of generation capacity by providing revenues to recover fixed costs of peaking plants (Creti & Fabra 2007; de Vries & Heijnen 2008; Joskow 2008; Cramton & Ockenfels 2012). In contrast to the wholesale market, compensation is not based on the produced electricity but on the generator availability (or installed capacity) to complement the energy-only market (e.g. Roques 2008) or even replace it (e.g. Boute 2012).

Capacity remuneration mechanisms have been subject to considerable debate over the last decade both in terms of the general need for them and the optimal design (Batlle & Pérez-Arriaga 2008; Neuhoff et al. 2011; Bhagwat et al. 2016). This is also exemplified by the application in practice. Capacity market designs for the UK and France are fundamentally different (RTE 2014a; DECC 2014), while Germany has entirely decided against the introduction of a capacity market (BMWi 2015). A detailed review of the advantages and disadvantages of various capacity mechanisms is beyond the scope of this thesis, however, some remarks regarding capacity mechanisms' ability to integrate intermittent renewables and capacity markets specifically are made.

A few papers assess the ability to integrate intermittent renewables of capacity remuneration mechanisms. Cepeda & Finon (2013) find that capacity mechanisms can help to decrease the social cost of large-scale wind power by decreasing the loss of load probability. Moreover, Neuhoff et al. (2016) elaborate that strategic reserves are especially beneficial for integrating renewables and the transition to a low-carbon electricity system as they are smaller in size and less prone to suboptimal parameter choices compared to capacity markets. Similarly, Bhagwat et al. (2016) state that given high generation from variable renewable energy, a strategic reserve reduces the cost to consumers as it stabilises thermal power investment cycles. In contrast, Henriot & Glachant (2013) argue that simple capacity mechanisms only increase complexity and are not needed for the introduction of intermittent renewable generations. However, if one decides in favour of the introduction of a capacity mechanism, it should include a fine level of spatial granularity that specifically addresses the needs for flexibility. Finally, Riesz & Milligan (2015) seek a compromise. They argue that there are effective examples of both energy-and-capacity and energy-only market designs and imply that therefore the choice of the market design might be less important for the integration of intermittent renewables, compared to its implementation and governance.

In general, modelling studies conclude that capacity markets reach generation adequacy in an economically efficient way. For example, using a dynamic capacity investment model, Hach et al. (2016) examine affordability, reliability and sustainability for several capacity market scenarios. They find for a case study in Great Britain that capacity markets increase generation adequacy, while decreasing lost load and the possibility of exercising market power. Hary et al. (2016) use a simulation model to consider dynamic effects of capacity markets and find that these help solve the adequacy issue, meaning that shortages are decreased in comparison to an energy-only market. However, case studies of already implemented capacity markets, e.g. in the US provide a less optimistic assessment of capacity markets. In an expert survey in the US, capacity markets provided incentives for generation adequacy but in an economically inefficient manner as they cause excess generation capacity (Bhagwat et al. 2016). This especially seems to be the case if the contribution of foreign capacities through interconnection is not considered (Newbery 2016).

In conclusion, the necessity and design of capacity markets and mechanisms is debated with respect to economic efficiency and integration of renewable energies among practitioners and academics alike. Consequently, some EU member states have already introduced or are planning to set up a capacity market or a myriad of capacity mechanisms, while others decided to remain with the energy only market. This might negatively affect cross-border trade, the internal energy market and perhaps renewable energy expansion in general (European Commission 2013a). An overview of the different proposals for capacity mechanisms in Europe are categorised and illustrated in Table 1 and Figure 4.

Strategic reserve	**Targeted capacity payment**	**Market-wide capacity payment**	**Central buyer**	**De-central obligation**
Belgium	Italy	Ireland	Ireland*	France*
Germany	Poland		Italy*	
Poland	Portugal		United Kingdom	
Sweden	Spain			

Table 1 Capacity remuneration mechanisms in the EU, * indicates plans (based on European Commission 2016)

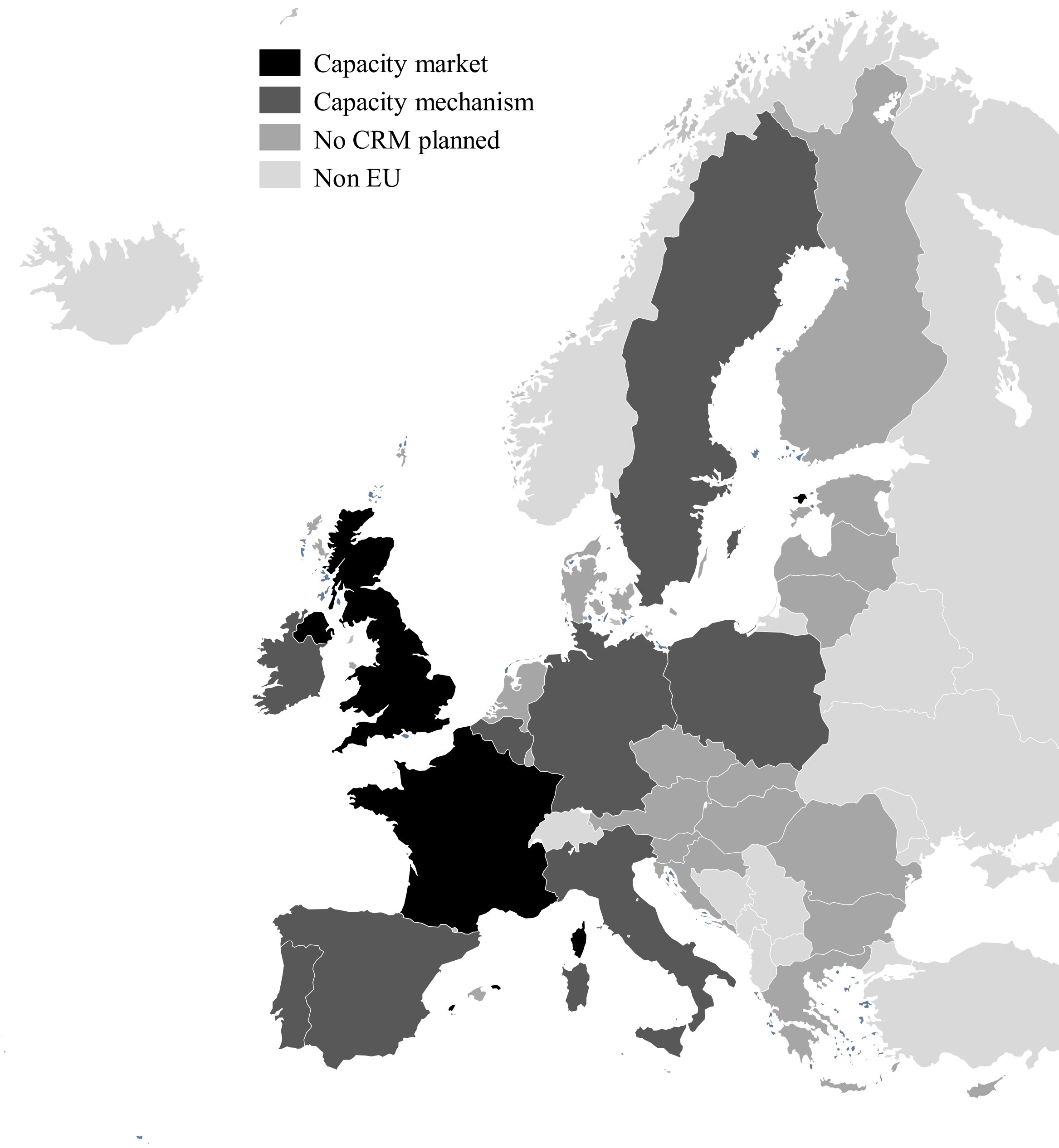

Figure 4 Capacity remuneration mechanisms in the EU (based on European Commission 2016)

2.3. Interaction of increased interconnection and capacity mechanisms

While interconnection is a possible solution to the intermittency issue of electricity from solar or wind and capacity mechanisms are a possible solution to the capacity issue, their interaction has received very little attention in the literature.

Some studies have assessed the interaction, primarily using complex electricity models. Using a two-country model over a time horizon of 30 years, Cepeda & Finon (2011) examine the effects of capacity mechanisms on investments and cross-border trade. Introducing a price cap and capacity market unilaterally and implicit foreign participation in the capacity market, they find no evidence for the proposition that countries with energy-only markets free-ride on the adequacy policies of the neighbouring market in the long-term. On the contrary, negative externalities occur in the energy-only market as price peaks decrease and peaking plants become unprofitable causing security of supply issues. These distortions are increased with larger interconnection between the two markets.

These results based on stylized energy markets are also reported for empirically grounded energy modelling studies. Similarly, Gore et al. (2016) find comparable effects for the case of the Finish energy-only and Russian energy-and-capacity market, and argue that increased interconnection might necessitate the introduction of a strategic reserve in Finland (Ochoa & Gore 2015). Moreover, for unilateral introductions of capacity payments in the cases of Colombia and Ecuador as well as France and the United Kingdom, similar effects are found (Ochoa & van Ackere 2014; Ochoa & van Ackere 2015). Finally, Meyer & Gore (2015) assess the effects of strategic reserves and reliability options on interconnected markets. Unilateral introductions of such mechanisms would thus lead to negative welfare effects for consumers and producers in total. In conclusion, these modelling studies suggest that integration and capacity policies should be coordinated or even homogenised to avoid negative cross-border effects.

However, several limitations prevail regarding the current literature. First, with some exceptions most studies do not quantify benefits arising from security of supply based on probabilistic methods, probably leading to an underestimation of overall benefits. Second, institutional factors such as different rationales and perceptions that might hinder the homogenisation of electricity market designs are not taken into account. Third, and most importantly they do not consider significant shares of intermittent renewable energy in their capacity mixes, being the primary reasons for the necessity of increasing interconnection and introducing capacity markets in the EU.

2.4. French and German Market designs

2.4.1. The German energy only market

In 2011, under the title of the "Energiewende", the German government committed to phasing out nuclear electricity by 2022, replacing it with energy from renewable sources. German plans to increase the share of renewables already started in 2000 through the adoption of the EEG, including feed-in-tariffs. As a result, electricity generation from renewables has increased from 6% in 2000 to 33% in 2015 (BMWi 2016). Although contributions from intermittent renewables to total generation fluctuate between 2 and 70% and sometimes even cause negative wholesale prices, Germany has decided against the introduction of a capacity market (BMWi 2015). Instead a capacity mechanism, precisely a strategic reserve, will be introduced in 2018 and will compensate 5% of peak demand, i.e. approximately 4 GW. These plants are not allowed to participate in the electricity market and are expected to be mothballed without this market intervention, which would cause issues regarding security of supply. Nevertheless, the German electricity market can still be characterised as an energy-only market.

2.4.2. The French electricity mix and the rationale for a capacity market

Due to technology choices in the 1970s and 1980s, France currently has a low-cost and low-carbon power industry compared to other EU member states. Large shares of nuclear power, currently comprising around 75% of the electricity mix, and hydroelectricity contribute to security of supply, affordability and low carbon emissions. This development also led to the increased use of electric heating to reduce fossil fuel dependence. As a result, these decisions have led to an "intense peak demand phenomenon" in France (RTE 2014a, p.4). While overall electricity demand has been falling in recent years, peak demand has been increasing sharply. To illustrate, during the winter of 2011-2012, maximum peak demand was 102.1 GW, while it was only 79.6 GW in the winter of 2001-2002 – an increase of 30 percent. France has a particularly temperature-sensitive electricity demand. During winter peak hours, demand rises by 2,400 MW for every 1°C temperature decrease. Climate change is likely to increase peak demand even further over the coming decades (RTE 2014a). Such sharp peak demand periods pose considerable risks to the security of supply. Before the discussion about the introduction of a capacity market, the resource adequacy report of the French TSO forecasted that the security of supply standard of 3 hours loss of load expectation (LOLE) is unlikely to be met from 2013 onwards (RTE 2009; RTE 2010). Although the slow recovery after the financial crisis might have delayed this problem, high peak demand remains a concern.

While the French electricity demand side already imposes challenges for capacity adequacy, these are enhanced by plans to decommission French nuclear power plants. By 2025, nuclear power should only comprise 50% of the electricity mix according to government targets. At the same time, intermittent renewables are forecasted to increase to 56 GW by 2030 – around 35% of total electricity supply (RTE 2014a). As a result, balancing demand and supply will become increasingly complicated over the next decades and exhibits a particular challenge to the provision of adequate back-up supply. Wider developments towards increased intermittent renewable electricity but also the French temperature-sensitive demand, have led to the proposed introduction of a capacity market to cope with these trends.

2.4.3. The proposed energy-and-capacity market in France

In 2012, the French government proposed the introduction of a capacity market through which suppliers would be allocated capacity certificates that can be traded with utilities in order for the latter to comply with their legal obligation (French Government 2012). The proposed capacity market (1) is technologically neutral, i.e. generation, demand side response and storage can bid into the market, (2) does not differentiate between new and existing electricity generators, (3) is designed as not interfere with the Internal Energy Market and (4) forward-looking.

At its core, the French capacity market aims to reward operators for their capacity availabilities during peak demand situations. On the supply side, demand side response and electricity generators commit to being available for a certain capacity during peak demand and are issued certificates accordingly. On the demand side, the French Transmission System Operator (TSO) assigns utilities obligations based on the projected consumption of their customers during peak periods. In order to meet these obligations, utilities either certify their own capacities or purchase certificates from demand side response, storage or generating capacities. The latter are traded bilaterally or on a market beginning four years prior to delivery. After the delivery period, utilities are reviewed concerning their capacity sufficiency given actual peak consumption and suppliers of certificates are reviewed concerning their availability. As part of the imbalance settlement, penalties are imposed in the case that a party cannot meet its obligations (RTE 2014a). An overview of the French capacity mechanism can be found in **Figure 5**

In 2015, the capacity market started for the first delivery years in 2017, 2018 and 2019. However, the market is currently on hold as the EU Commission investigates whether the French capacity market is effectively state aid (European Commission 2016).

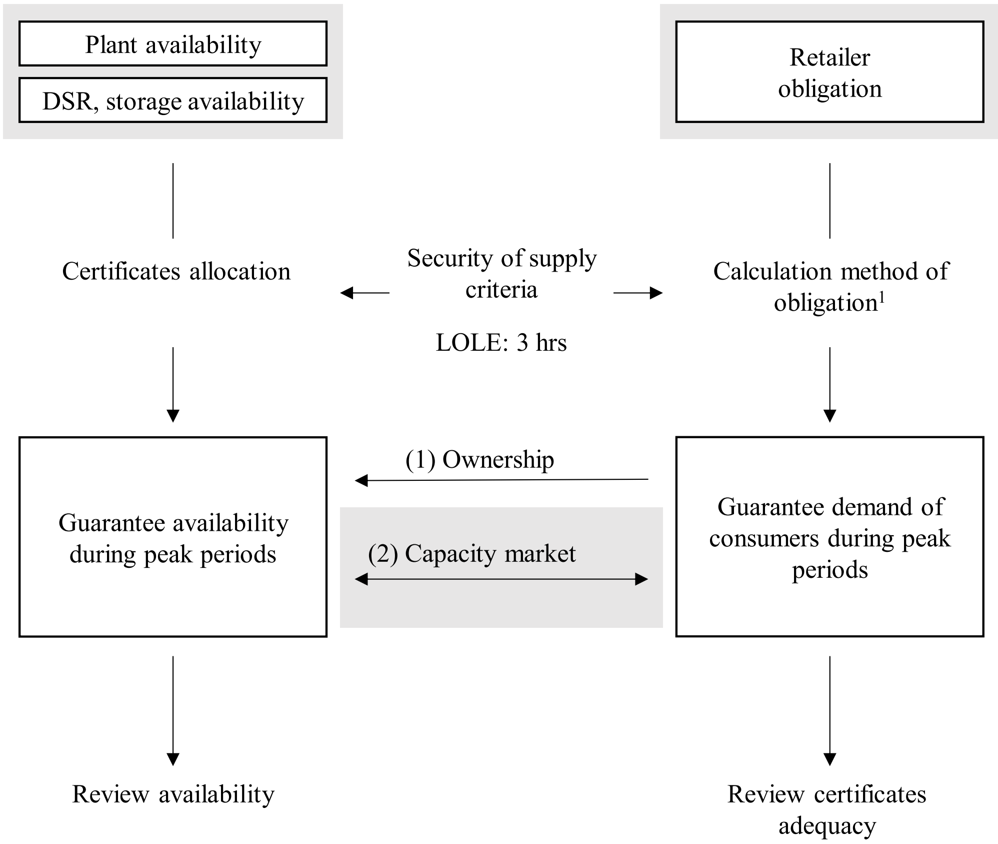

Figure 5 French capacity market (based on RTE 2014b), [1]Based on consumer demand, temperature sensitivity and interconnection

3. Methodology

3.1. Mixed methods approach

3.1.1. Description of design and justification

To investigate the research question, theoretical (economic analysis), qualitative (semi-structured interviews) and quantitative methods (empirically-grounded energy system modelling) were used. There are several reasons for the appropriateness of this approach given the research question. First, the research design enables the comparison of fundamental economic principles with modelling results and stakeholder expectations to consider a variety of analyses and explore differences and commonalities. Second, semi-structured interviews were considered in framing the modelling approach and design. Third, modelling results can be interpreted in light of stakeholder views to deepen and triangulate findings to minimise biases that might result from the use of only one methodological approach. Further justification of the specific methods used can also be found in the limitation section.

3.1.2. Justification of case study selection

Moreover, the case study of French and German electricity market designs seems appropriate to both limit scope and draw general implications. First, discussions about the introduction of capacity markets and interconnections are a current topic in these countries, which ensures that stakeholders have an informed view. Second, the focus on a particular case enhances the appropriateness of the modelling approach by making it applicable to the case instead of modelling stylised facts. Third, the case study is instrumental in understanding the effect of connecting different electricity markets and decarbonisation pathways. In addition to different decisions around capacity markets, France focuses on nuclear and increasingly intermittent renewables while Germany aims at increasing intermittent renewables to decarbonise their energy system. Nevertheless, the case study enables to draw wider implications on the interconnection of different market designs and polycentric governance.

3.2. Theoretical economic analysis

To determine the economic value of capacity markets and interconnection in combination with intermittent renewable generation, I derive a theoretical framework and formulate the fundamental relationships using economic analysis following Becker (1968). Here, I consider the economic effects of increased interconnection and capacity markets, while assuming perfectly competitive electricity markets. Additional assumptions will be stated directly in the analysis.

3.3. Interview methodology

3.3.1. Participant selection

In order to qualitatively examine the research question, 14 interviews with a total of 15 experts and stakeholders were conducted. To gain a comprehensive overview of the different opinions with a focus on the French and German case, semi-structured interviews were used as the selected method, with key decision-makers on the French, German and European side. Utility companies, transmission system operators, regulators and energy ministries in both countries as well supranational institutions such as the EU, ACER and ENTSO-E were included. Potential participants were selected based on their expertise with regards to interconnection and capacity mechanisms. They were identified via contacts from my supervisors and other persons within the Environmental Change Institute, contact persons in reports on the issue, a search on the professional network LinkedIn and organisations' webpages and thus represent a convenience sample. Unfortunately, no interview with the French Ministry could be conducted. An overview of interviewed persons and organisations can be seen in

	Organisation	**Description**
European stakeholders	ENTSO-E	European Network of Transmission Service Operators
	EU, DG COMP	European Union
	ACER	Agency for the Cooperation of Energy Regulators
French stakeholders	EDF	Utility company
	RTE	Transmission System Operator
	CRE	Regulator
German stakeholders	BDEW	Federal Association of the German Energy and Water Industry
	Vattenfall	Utility company
	EnBW	Utility company
	TenneT	Transmission System Operator
	50Hertz	Transmission System Operator
	BNetzA	Regulator
	BMWi	Federal Ministry for Economic Affairs and Energy

Table 2 Expert interview participants

3.3.2. Interview protocol

Contacts were approached via email and a 20-25 minute Skype or telephone call was arranged if they agreed to participate. These interviews were conducted between June and early August 2016. Due to the spatial dispersal of stakeholders, personal interviews were not possible except for one case. A semi-structured question guide was followed to investigate the interviewee's opinion of interconnectors, capacity markets and their interaction. Interviews were recorded if permitted, afterwards transcribed, and finally coded. Otherwise notes were taken. The Ethics Committee approved the methodology, their guidelines were followed and participants' requests were considered. Interviews were analysed using thematic analysis (e.g. Boyatzis 1998). Given experts with a similar cultural background, this is an appropriate methodology to systematically analyse responses.

3.4. Modelling methodology

3.4.1. Modelling overview

For the modelling part of this dissertation the European electricity market model of Aurora Energy Research (AER-ES) was used. It models 15 European countries, including Germany and France as well as their neighbouring countries. Given the scope of the project and the complexity of the research topic, a complex electricity market model is an appropriate choice. The overall objective function of the model is to minimise total system costs while maximising profits for individual plant owners. Specifically, the model assumes perfect competition and simulates the dynamic dispatch of plants subject to efficiencies, ramping cost, rate restrictions and stochastic availability of plants, which are calibrated using historical data since 2005. Hourly demand functions are assumed to be inelastic to price. Intermittent renewable productions are modelled based on normalised historical load factor patterns scaled by the corresponding yearly capacity. Load factors are increasing over time to simulate technology improvement. Fuel prices are derived from Aurora Energy Research models for global energy commodities (AER-GLO) and regional gas markets (AER-GAS). For computational efficiency, 12 representative days, i.e. three per season, are modelled for each year on hourly granularity. For each hour and country, the market clearing equation is solved. To determine wholesale prices, net production, imports and unserved electricity (loss of load) is set equal to demand, export and spill (electricity overproduction):

$$Net\ production_t + Imports_t + \ Unserved\ electricy_t = \ Demand_t + Exports_t + Spill_t$$

German capacities are based on BNetzA (2016) and comprise 197 GW in 2015, of which 81 GW are intermittent renewables. At the beginning of each year, investment decisions of thermal plants are modelled endogenously considering net present value of expected returns assuming perfect foresight. French capacities are assumed exogenously as investment and divestment decisions are largely driven by French policies, e.g. nuclear decommissioning. In 2015, French capacity comprised 129 GW, of which 15 GW were intermittent renewables (RTE 2016b). Spot prices in both countries are calibrated using historical capacity, production and demand data from 2013, 14 and 15 from the French TSO (RTE 2016a) and ENTSO-E (2016). For a more detailed description of the model refer to AER (2016).

3.4.2. Interconnectors

For cross-country interconnectors, interconnector flows are modelled endogenously and calibrated using commercial flows for the years 2013-2015 (ENTSO-E 2016). Interconnectors are assumed to have a lifetime of 40 years and costs of 100,000 EUR/MW similarly to Lynch et al. (2012). I base interconnector capacities on the yearly average of hourly data in 2013, 14 and 15, which represents commercially available capacities between countries. These are lower than technical capacities; in extreme cases even consistently 0 if loop flows prevail. Assuming that loop flow issues are solved and interconnections are used more efficiently by 2020, capacities are linearly increased to the maximum of observed hourly commercially available capacities in 2014 and 2015. Future interconnector capacity expansions are based on the ENTSO-E Ten Year Network Development Plan (TYNDP) 2016 and added with a 0.8 derating factor to approximate commercial capacities.

3.4.3. Scenario formulation

To investigate the effects of the interaction of a unilateral capacity market introduction and simultaneous increase in interconnection, I ran the model for 18 scenarios (see Table 4). For the capacity market, two dimensions are included, one with a capacity market in France and another without. For interconnection, three dimensions are defined, a low case with capacities remaining on the current level, a base case building on the TYNDP and a high case with double the capacity indicated in the TYNDP in 2030. A timeline of interconnection capacities can be seen in Table 3. Demand is assumed to be the same across all scenarios. In 2030, French demand is projected to be 501 TWh according to the diversification scenario (RTE

2014c). German demand is projected to be 573 TWh by 2030, which is based on 1.1% annual GDP growth, approximately constant population, no significant electrification of heating, modest uptake of electric vehicles of 22% by 2040 and annual efficiency improvements of approximately 1.5% (AER 2016b).

IC Capacity FR-DE (MW)	**2016**	**2020**	**2025**	**2030**
Low interconnection	2534	2534	2534	2534
Base interconnection	2534	2900	3020	3620
High interconnection	2534	3300	4800	7240

Table 3 DE-FR Interconnection capacity expansion

	Low interconnection	Base interconnection	High interconnection
Base case without capacity market			
Base case with capacity market			
French government targets without capacity market			
French government targets with capacity market			
German coal exit without capacity market			
German coal exit with capacity market			

Table 4 Overview of modelling scenarios

Given considerable uncertainty in electricity systems (Spiecker et al. 2013), e.g. regarding policies for generation mixes, three dimensions with different capacity mixes are considered as well. Although not being collectively exhaustive, they deliver the option to explore a range of possible futures. The scenarios were developed based on German and French policy plans and suggested by interviewees. The first scenario includes German and French base capacity timelines. The German capacity timeline considers the nuclear phase-out by 2022 and the Renewable Energy Act 2017 for renewable energy while modelling other capacities endogenously. The French capacity timeline is based on the "diversification" scenario of RTE (2014b), which is also used by the French TSO assessment to determine the influence of its capacity market (FTI 2016). The second scenario assumes a compliance with French discussed policy plans to limit nuclear plant's share of generation to 50% by 2025 from 2019 and an increase in renewable generation to 30% by 2030, while keeping the German base case. This enables the examination of the effects of increased intermittent renewables. The third scenario assumes a German coal exit by 2040 while keeping French base capacities, to decrease the German capacity margin while simultaneously having large shares of intermittent renewables. An overview of the capacities for different scenarios in 2030 is depicted in Figure 6.

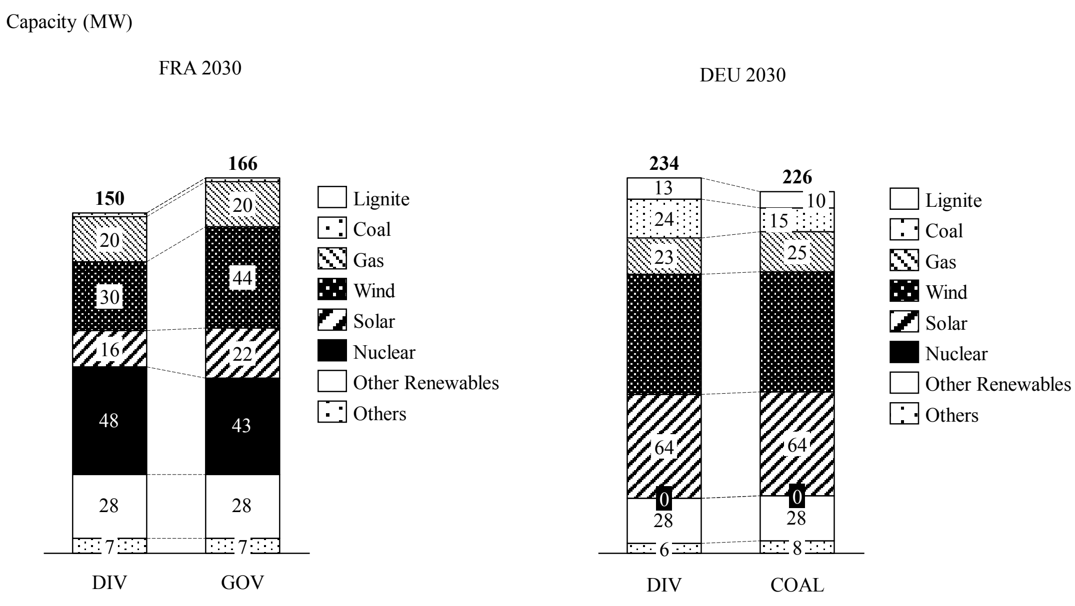

Figure 6 Plant capacities per technology in differing modelling cases[1]

3.4.4. Loss of load expectation and capacity market simulation

In order to model the effect of the capacity market on French capacities, I use the following approach. The required capacity to meet 3 hours LOLE in France is determined based on a

[1] DIV, GOV, COAL represent base case, government targets and coal exit, respectively

Monte-Carlo analysis for the years 2020, 2025 and 2030 following Haroonabadi & Haghifam (2011) and DECC (2013b). For each of these years, 25 samples of each country's distribution of wind generation, solar generation, thermal capacity availability and interconnector availability as well as demand are randomly drawn from each reference year 2010 until 2014. For each of these 125 samples, all hours of the year are simulated to determine how much capacity is required to meet 3 hours LOLE if these patterns occur in years 2020, 2025 or 2030. The capacity needed in the years in between is then interpolated linearly. To estimate the effects of the capacity market on the French capacity timeline, I assume that the capacity required to meet the 3 hours criterion is added as efficient gas plants (1/3 open cycle gas turbines, 2/3 closed cycle gas turbines). Their investment costs are estimated with 360,000 and 650,000€/MW, respectively. Although the French capacity market is designed neutrally in terms of incentivised technologies, this seems to be a reasonable assumption that is also confirmed by the French capacity market assessment (RTE, 2016), although the influence of demand side response is likely underestimated. However, the assessment which technologies, e.g. gas peaking plants, demand side response and storage, will participate in the capacity mechanism is difficult to predict, largely driven by assumptions about costs and highly controversial (European Commission 2016). I will discuss my results in light of this assumption. For the size of the capacity market I add derated capacities approximated using UK factors and add the capacity as determined by the Monte-Carlo analysis. The result is multiplied with yearly plant fixed costs of the new capacities minus their revenues in the wholesale market to approximate the capacity price. I use a discount rate of 9%, which is reasonable for the French and German electricity market. Furthermore, I use a value of lost load (Voll) of 10,000€/MWh, similarly to Cepeda et al. (2009). Both markets have price caps at 3,000 EUR/MWh. Finally, in line with the current proposal, interconnectors are only implicitly taken into consideration when calculating LOLE, but foreign plants cannot explicitly bid into the capacity market.

3.4.5. Measuring effects

To assess the unilateral introduction of a capacity market in France, I will consider effects on the three dimensions of the energy policy trilemma, primarily economic efficiency, security of supply and CO_2 emissions. First, effects on security of supply will be assessed in both countries, especially the capacity needed to cover 3 hours of loss of load expectation. Second, differences in welfare effects including consumer, producer and interconnector rent will be assessed under different scenarios. Third, the effect on CO_2 emissions will be examined. These dimensions were also confirmed in the interview as main criteria for decision-making.

4. Results

4.1. Theoretical economic analysis

In order to assess to what extent interconnection and capacity markets are combinable, I determine to what extent and under which conditions capacity markets and interconnections are substitutes with regards to economic value from a country's perspective. Using, the following theoretical analysis, I especially focus on the influence of intermittent renewables in terms of correlation of residual demands. I consider economic welfare as well as security of supply effects while ignoring carbon emission effects as these largely depend on assumptions about the emissions of technologies in interconnected markets as well as the social cost of carbon. Therefore, the following economic framework aims to determine the economic value of interconnection between two markets, the value of a unilateral capacity market as well as their interaction from the energy-and-capacity market perspective.

Four parts determine the change in total yearly value through an increase in interconnection and the introduction of a capacity market. First, the change in value of increased interconnection $\Delta V_{IC}(\Delta Q)$ is a function of the interconnector capacity increase ΔQ. Second, $K_{IC,t}(\Delta Q)$ describes the yearly depreciated and discounted investment cost of interconnection. Here, it is assumed that France and Germany finance half of the investment costs each. Third, the cost of the capacity market $K_{CAP}(\Delta Q, C_{FR})$ is a function of interconnection capacity and the additional French capacity C_{FR}, that the capacity market provides. Fourth, the benefit of avoided loss of load $\Delta V_{Alol}(\Delta Q, C_{FR})$ also depends on both interconnection and the required French capacity. As a result, the total yearly change in economic value ΔV through a simultaneous interconnection increase and capacity market introduction can be described as

$$\Delta V = \Delta V_{IC}(\Delta Q) - \tfrac{1}{2} K_{IC,t}(\Delta Q) - K_{CAP}(\Delta Q, C_{FR}) + \Delta V_{Alol}(\Delta Q, C_{FR}) \quad \text{with } \Delta Q, C_{FR} > 0 \quad (1)$$

The components are described in more detail in the sections below and an overview of the relations can be seen in Figure 7.

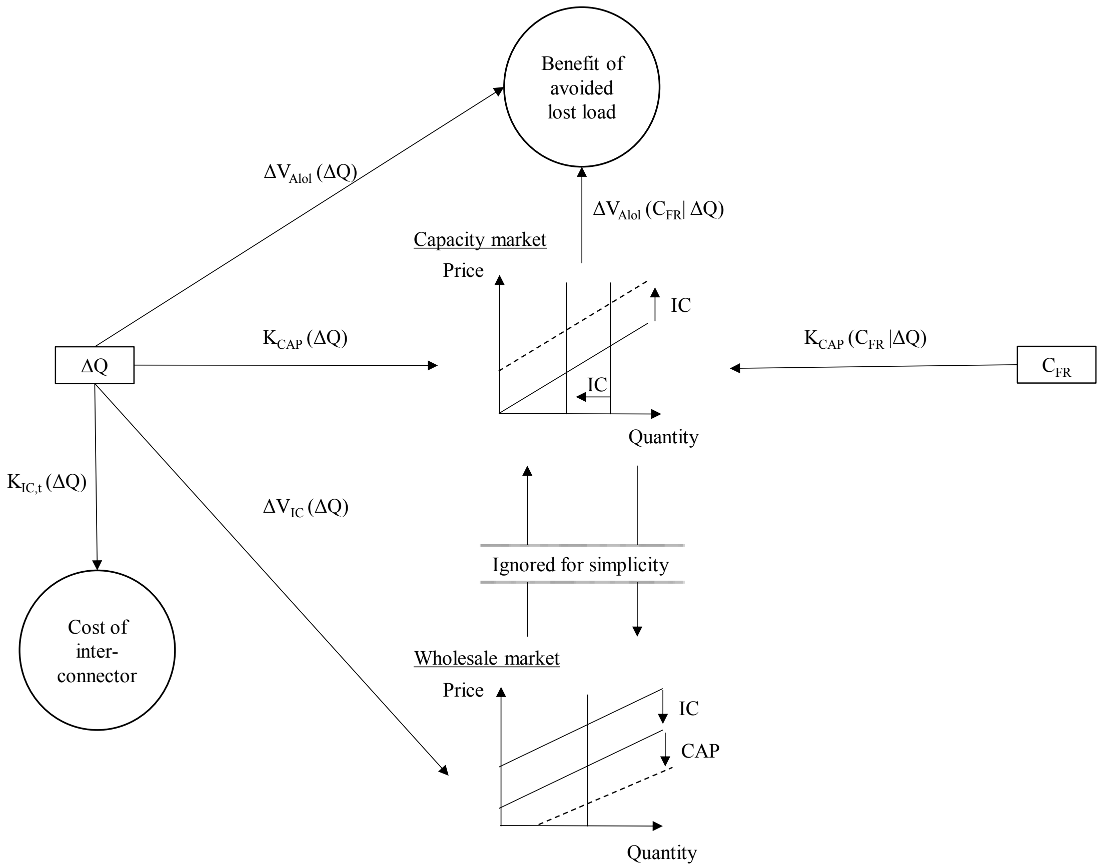

Figure 7 Overview of interaction of capacity market and interconnection, assuming FR importing at all times (Author's own)

For simplicity, I ignore two effects in this theoretical economic analysis. First, the wholesale market effect of the capacity market is not considered. In the long run, the capacity market could lower wholesale prices by incentivising new low marginal cost capacity, and influence the merit order. However, as the capacity market should primarily incentivise the construction of peaking plants that only run a few hours a year, the effect on wholesale prices is here assumed to be small. Second, I do not consider the indirect effect of increased interconnection via the wholesale market on the capacity market. As more interconnection influences wholesale prices, the capacity market price could be influenced, too. A lower/higher wholesale price would lead to less/more income for plants resulting in higher/lower capacity market price bids and thus a higher/lower capacity market price. However, this might only be true if plants deviate from bidding their fixed costs. Although these effects are ignored in the formulation of the theoretical framework, they are depicted as dotted lines in Figure 7. Moreover, they will be included in the modelling part.

4.1.1. Yearly benefits from interconnection: Wholesale market effect

The yearly welfare increase from increased interconnection in France can be formalised as

$$\Delta V_{IC}(\Delta Q) = \sum_h \left(\Delta V_{CS} + \Delta V_{PS} + \frac{1}{2}\Delta V_{ICRent}\right) \quad (2)$$

with hourly increases in consumer surplus ΔV_{CS} if France imports, increases in producer surplus ΔV_{PS} if France exports and the change in interconnector rent ΔV_{ICRent} that is here split evenly between France and Germany. Here, I ignore redistribution effects, i.e. transfers from producer to consumer rent or vice versa, within a particular country, as they do not enhance economic efficiency.

I assume French and German wholesale supply curves, S_{FR}: $P_{FR} = mQ_{FR} + u$; and S_{DE}: $P_{DE} = mQ_{DE} + v$; as well as equal price-inelastic demand and capacities in both countries. Further, in order to reduce complexity, I assume here that France is only importing. Then producer rent increase, consumer rent increase and interconnection rent can be described as follows:

$$\Delta V_{CS,FR} = \frac{1}{2}(mQ_{FR} + u - (mQ_{FR} + (u - lv)) \cdot \Delta Q = \frac{1}{2} lv \cdot \Delta Q \quad \text{[with l > 0]} \quad (3)$$

$$\Delta V_{PS,DE} = \frac{1}{2}\left((mQ'_{DE} + u) - (mQ_{DE} + u)\right) \cdot \Delta Q = \frac{1}{2} m(\Delta Q)^2 \quad (4)$$

$$\Delta V_{ICRent} = \Delta Q \cdot (P_{FR'} - P_{DE'}) = \Delta Q \cdot \Delta P' \quad (5)$$

ΔQ describes the hourly export from France to Germany. It is assumed to be equal to the interconnection capacity here. For the case that France is importing, Figure 8 shows the increase in French consumer rent A, increase in German producer rent B and the change in interconnector rent C, assuming that it was 0 previously. The interconnector rent C, i.e. the electricity flow through the interconnector multiplied with the price differential between both countries, can either be depicted in France or Germany and is equal to area D.

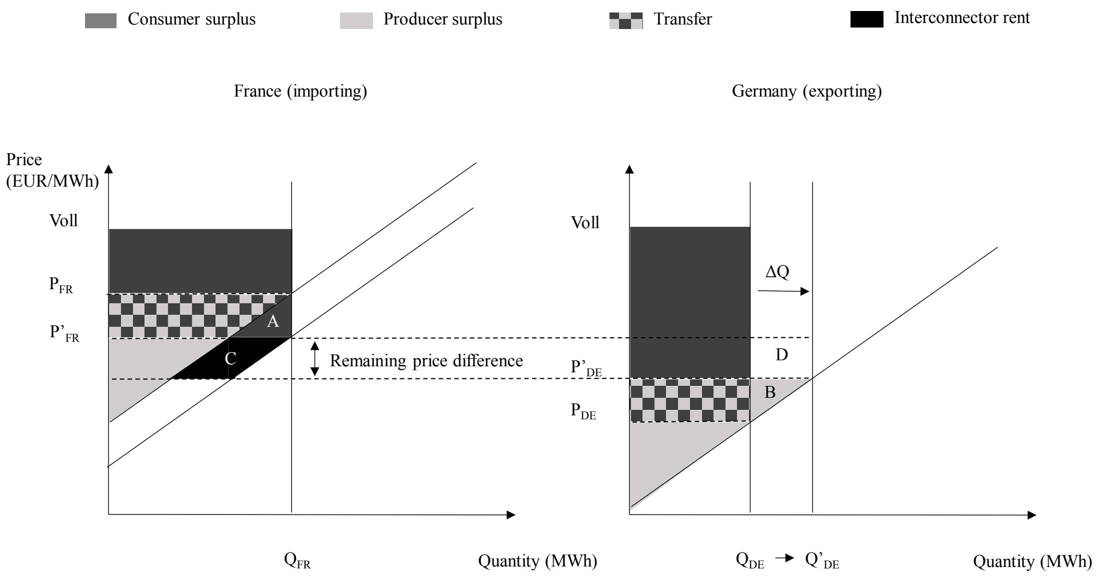

Figure 8 Effects of interconnection on the wholesale market in two interconnected markets (based on Turvey (2006); AER (2016a))

If interconnector capacity ΔQ is increased further, such that the price differential in both markets ultimately becomes 0 at all times, the additional benefit from increased interconnection is declining, which can be seen in Figure 8. Therefore, assuming that France is importing in all hours of the year, the yearly benefit from increased interconnection can be described, with scaling factor z >0, n>1:

$$\Delta V_{IC}(\Delta Q) = z\, \Delta Q^{\frac{1}{n}} \qquad (6)$$

4.1.2. Yearly costs from interconnection

Yearly investment costs from interconnection can be described as a function of interconnection capacity and represent a depreciated and discounted component of interconnector capital, maintenance and operating expenditure. For simplicity, yearly investment costs can be described as depreciated and discounted investment costs per capacity k_t, multiplied with interconnection capacity ΔQ:

$$K_{IC,t}(\Delta Q) = k_t\, \Delta Q \qquad (7)$$

4.1.3. Yearly net cost of the capacity market: Capacity market + interconnector

Large parts of the cost of the capacity market, although faced by consumers, will benefit producers and are thus a redistribution of welfare. However, the yearly net cost of the required capacity for France with interconnection can be described as the required capacity $C_{FR,DE}$ for a loss of load expectation of 3hrs – the French security of supply criterion - multiplied with the capacity price λ.

$$K_{CAP}(\Delta Q, C_{FR}) = C_{FR,DE} \cdot \lambda \tag{8}$$

Additionally, a stylized capacity supply curve can be defined with a depending on the fixed and investment costs of the technologies bidding into the capacity market.

$$\lambda = a\, C_{FR,DE} \tag{9}$$

Without interconnection, $C_{FR,DE}$ is equivalent to C_{FR}. However, with interconnection the capacity required might likely be lower depending on the correlation coefficient of residual demands in France and Germany $r_{FR,DE}$ ($-1 < r_{FR,DE} < 1$), interconnection capacity ΔQ and the scaling factor $b > 0$. Residual demand is defined as demand minus intermittent generation.

$$C_{FR,DE} = C_{FR} - b \cdot \Delta Q \cdot (r_{FR,DE} - 1)^2 \tag{10}$$

The benefit from interconnection is larger for a negative correlation of residual demand than positive, as security of supply emergency situations are less likely to happen at the same time. During simultaneous security of supply emergency situations in both countries, it is assumed that the interconnector is not used. As a result, for perfectly positive correlated residual demand in both countries, the interconnector does not provide any benefit, given the same market sizes and demand in both countries. Consequently, the yearly net cost of the capacity market for French plants with interconnection can be expressed as

$$K_{CAP}(\Delta Q, C_{FR}) = a(C_{FR} - b \cdot \Delta Q \cdot (r_{FR,DE} - 1)^2)^2 \tag{11}$$

A simplified overview of the relation between the capacity required depending on residual demand correlation and the capacity price can be seen in Figure 9.

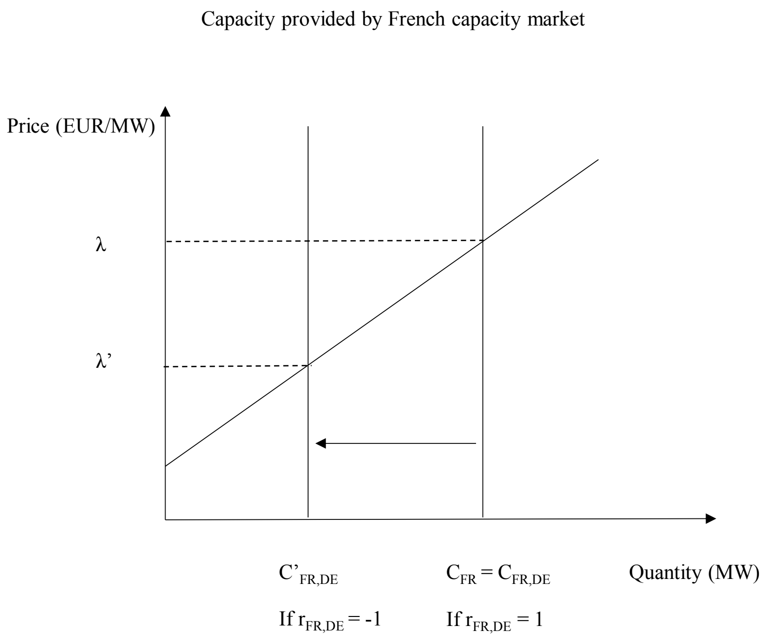

Figure 9 Net costs of French capacity market for different correlation coefficients of residual demand in interconnected markets (Author's own)

4.1.4. Yearly benefits from avoided lost load: Capacity market + interconnector

The benefit of avoided lost load $\Delta V_{Alol}(\Delta Q, C_{FR})$ can be broken down into a capacity market and an interconnection component. The effect of increased interconnection $\Delta V_{Alol}(\Delta Q)$ on avoided lost load, equals the value of lost load to consumers *Voll*, multiplied by the increase in the hours of avoided loss of load Δh_{lol1} and the depth of the lost load d_l. In case of a blackout, d_l would equal demand in France.

$$\Delta V_{Alol}(\Delta Q) = Voll \cdot \Delta h_{lol1} \cdot d_1 \tag{12}$$

The increase in the avoided hours of loss of load Δh_{lol1} is itself assumed to be a function of the correlation of residual demand, in France and Germany $r_{FR,DE}$ and interconnection capacity with scaling factor s > 0:

$$\Delta h_{lol1} = \mathrm{s}\, \Delta Q (r_{FR,DE} - 1)^2 \tag{13}$$

The benefit from interconnection is declining from negative to positive correlation of residual demand as security of supply emergency situations are more likely to happen at the same time. Therefore, the possibility of averaging out demand patterns over space via interconnectors decreases as demand is more correlated. Nevertheless, increased interconnection increases the avoided hours of lost load, although to a smaller extent with high correlation of residual demand between France and Germany.

The second component of the value of avoided lost load $\Delta V_{Alol}(C_{FR}|\Delta Q)$ describes the increase in the avoided hours of loss of load due to increased peaking capacity incentivised by the capacity market, given interconnection and similarly equals the value of lost load multiplied with the hours of avoided lost load Δh_{lol2} and the depth of lost load d_2.

$$\Delta V_{Alol}(C_{FR}|\Delta Q) = Voll \cdot \Delta h_{lol2} \cdot d_2 \quad (14)$$

The increase in the avoided hours loss of load Δh_{lol2} itself is a function of the required capacity, with scaling factor $w > 0$.

$$\Delta h_{lol2} = w\ C_{FR,DE} \quad (15)$$

As a result, the combined benefit of interconnection and capacity market on avoided hours of loss of load per year can be described as the combination of equations (12-15) defined above. The two components can be added, as they are mutually exclusive and collectively exhaustive. Additionally, $C_{FR,DE}$ can be expressed as C_{FR} following equation (11).

$$\Delta V_{Alol}(C_{FR}|\Delta Q) = Voll \cdot s\Delta Q\left(r_{FR,DE} - 1\right)^2 \cdot d_1 + Voll \cdot r\left(\Delta C_{FR} - b \cdot \Delta Q \cdot \left(r_{FR,DE} - 1\right)^2\right) \cdot d_2 \quad (16)$$

4.1.5. Total change in welfare from interconnection and capacity market

Building on equation (1) and inserting the yearly net benefit from interconnection (7), the yearly cost from interconnection (8), the net cost of the capacity market (12) and the benefit of the capacity market (16) one arrives at:

$$\Delta V(\Delta Q, C_{FR}) = z\,\Delta Q^{\frac{1}{n}} - k_t\,\Delta Q - a(C_{FR} - b \cdot \Delta Q \cdot (r_{FR,DE} - 1)^2)^2$$
$$+ Voll \cdot s\Delta Q\left(r_{FR,DE} - 1\right)^2 \cdot d_1 + Voll \cdot r\,(C_{FR} - b \cdot \Delta Q \cdot \left(r_{FR,DE} - 1\right)^2) \cdot d_2 \qquad (17)$$

In conclusion, given perfect positive correlation of residual demand, the capacity market provides benefits in security of supply while posing quadratic increases in costs for increasing capacity incentivised. Interconnection provides economic value through the net increase of economic welfare while its costs increase linearly with increased interconnection. Thus, the value of both interconnection and capacity market are concave functions for $\Delta Q, C_{FR} > 0$. Given less correlation or even negative correlation of residual demand, which might be caused by different spatial renewable generation patterns, the interconnector increasingly adds value through providing security of supply and reducing the net costs of the capacity market. It thus becomes a substitute with respect to security of supply. However, given the complexity of the relationships, and to consider an empirically-grounded example, an electricity market model will be considered in section 4.3.

4.2. Expert interviews with stakeholders

A total 13 of semi-structured expert interviews with stakeholders were conducted to examine to what extent interconnection and capacity mechanisms can be combined with each other. Thematic analysis was used to analyse (1) the perception of interconnection and capacity markets, (2) the necessity to homogenise capacity mechanisms given interconnection and (3) the effects of unilateral introductions of capacity markets. Core codes that resulted from the interview analysis are marked in *italic*. Interviewees include key decision-makers within energy utilities, transmission system operators, regulators and the energy ministries in both countries, as well as the involved European and transnational institutions. As a note of caution, opinions voiced by the participants represent their own views and do not necessarily be those of the organisation.

4.2.1. Rationales for market integration and interconnection

Although there seemed to be a consensus among interviewees that internal energy market integration and increased interconnection was a positive and necessary initiative, rationales differed substantially. A first dominant reasoning concerned *economic efficiency* and *welfare enhancement* and was mentioned by almost all interviewees in both countries, primarily utilities. Given different generation fleets within Europe and load patterns, cheaper sources of energy production could be used more efficiently through increased market integration. Similarly, interconnector projects should be scrutinised on an individual basis to examine whether a specific project is actually welfare enhancing. The second line of reasoning primarily raised by German and European organisations was about the *integration of volatile and intermittent renewable energy sources* while simultaneously decommissioning a large part of established energy production assets. The internal electricity market even was mentioned as an inevitable step towards renewable energy integration by some interviewees. Finally, some mentioned the positive effects on *security of supply* if backup capacities could be used for a larger geographical area. While some argued that more ambitious reforms would be needed rather than a simple optimisation of the current energy system, noone voiced any concerns about the fact that increased market integration might be at odds with at least one pillar of the energy trilemma.

However, most participants mentioned that although an internal market integration was generally positive, the physical aspect, i.e. more interconnection between countries, was currently still *developed insufficiently.* While TSOs argued that steady progress had already been made in the last decade with regards to interconnection, others reasoned similarly but pointed out that many of the projects were delayed for administrative, financial, distributive and political reasons, similarly to Puka and Szulecki (2014).

4.2.2. The necessity of capacity markets

Similar to the academic literature, there was no general consensus on the necessity of a capacity market. However, perhaps unsurprisingly, most French stakeholders argued that it would be necessary while most German stakeholders thought the opposite, although with reservations. Currently, meeting the security of supply criterion in Germany seemed to be no issue and therefore, capacity markets were not considered necessary. However, given plans of expanding *intermittent renewables* and the *phase-out of nuclear plants*, the energy only market might not be sufficient to guarantee security of supply in the mid twenties and at least a capacity mechanism albeit a market might be necessary as some mentioned. In contrast, French stakeholders uniformly believed that a capacity market was necessary given plans to phase out existing capacities and increase of *intermittent renewables* combined with a *highly temperature sensitive demand*. Some even saw it as fully-fledged complement to an energy market to ensure the public good of security of supply. While the positions of German and French stakeholders were as expected, European institutions argued that in the long-term a capacity mechanism might not be necessary as the *demand side would become sufficiently flexible*. However, one should not inhibit current proposals for capacity mechanisms, as they might be necessary for a particular region, as long as they do not block the move towards increased demand side response.

4.2.3. The necessity of a homogenous solution

As established above, EU member states have different rationales with regards to both interconnection and capacity markets. At the same time, given plans for increased integration of EU energy markets, the question arises whether it was necessary to have a uniform solution of capacity mechanisms for all member states or whether one could leave it up to national discretion. Views were controversial with regard to this point, too.

Some believed that it was in principle necessary to have homogenous mechanisms. Differing solutions might lead to market *distortions and redistribution effects*. These effects might be further enhanced with plans for increased interconnection and thus even endanger the successful implementation of the internal energy market. As a result, mechanisms would have to be very similar or even identical to minimise negative effects.

In contrast, others argued that member states had different perceptions of the risk of security of supply. As security of supply was primarily a matter of national discretion, and only some countries had a consistent objective for security of supply, e.g. the Netherlands, Germany, France and the UK with 3 hours loss of load expectation, it remained a challenge to unite Member States around one homogenous capacity mechanism. Moreover, not only *political hurdles* but also *technical hurdles* to the homogenisation of energy market designs were mentioned. Capacity mechanisms had to be designed to address the specific problem of the member state or region. For example, temperature sensitive demand to cold spells during the winter in France might require a different mechanism compared to countries with temperature sensitive supply to heat spells of hydrogenation during the summer e.g. in Portugal or Norway, and there is no one-size fits all solution.

Some also recommended a compromise. While it might be desirable to have mechanisms that were not too different from each other, for *political and coordinative reasons* this might not be possible. Thus, it should be ensured that mechanisms do not remain only national but also include the explicit participation of foreign capacities. Here, *coordination and communication* among member states was stressed as a crucial element if one would decide for largely national solutions in order to address security of supply emergencies effectively.

Finally, there was some dispute about sequence. On the one hand, some mentioned that it would be necessary to have *unified capacity mechanisms before* one could increase interconnection due to the market distortions they expect. On the other hand, others reason that increased interconnection would lead to an *alignment of capacity mechanisms* as problems might be exported with increased interconnection. For example, if France had to import electricity during the winter, neighbouring countries might run into security of supply issues, too, requiring the set-up and alignment of capacity mechanisms. In conclusion, there remained large disagreement about the necessity to have a homogenous European electricity market design, but interconnection would require or cause the alignment at least to some extent.

4.2.4. The consequences of lacking coordination

Given that there is no consensus about whether it was necessary to have homogenous energy market designs, the question arises what the effects and their magnitude of the unilateral introduction of capacity markets would be. With regards to this issue, there is also much controversy among stakeholders and experts.

Some reasoned that effects would be small or non-existent. As the design of the French capacity market aimed to incentivise only 2-3 GW, or 10 GW according to other sources, the impact on France itself but also on neighbouring countries would be *small compared to other policies* such as the nuclear phase-out. Other lines of reasoning were that there would be no impact on German energy markets if the French capacity market was *well calibrated*, which largely depended on the details of the market design.

Others asserted that unilateral introductions of capacity markets might result in *market distortions and distribution effects*. First, there may be free-riding effects, as for example Germany could benefit from the flexible capacity supplied by the French capacity market during emergency situations. French consumers would have to pay for the provision of these capacities. Second, interconnection would lead to the issue that neighbouring countries would *import a missing money problem.* As demand spikes would primarily be met by peaking plants from the country with a capacity market, neighbours' peaking plants would not be compensated sufficiently to cover their fixed costs, a distortion of competition. As a result, loss of load expectation would increase in the neighbouring country. This melt-off effect of foreign capacities would be increased by additional interconnection, requiring the set-up of a capacity mechanism there as well. This market distortion could be overcome by allowing the explicit participation of foreign capacities in the French capacity market to avoid an intra-country preferential treatment.

A third group of interviewees explained that the interaction of unilateral capacity markets was a *complex problem*. It was thus impossible to make any definitive statement regarding the exact interaction and effects of unilateral introductions of capacity markets. Finally, several interviewees stressed that increased *coordination and communication* among neighbouring member states would become necessary to deal with security of supply emergency situations. This was especially important with increased interconnection as this would mean that security of supply no longer was a national concern but became a European one. As the European Union was largely built on trust, the mutual support during these situations would become a pivotal step to demonstrate the legitimacy of increased interconnection and the internal energy market. As a result, the communication of member states and establishment of protocols and regulations for emergencies was an issue of utmost importance according to some. In conclusion, large disagreement seemed to prevail among interviewees about the effects of unilateral introduction of capacity markets combined with (increased) interconnection capacity.

Notably, there seemed to be no consistent pattern among interviewees with respect to the question of interaction. In Germany, France and European institutions some expected large distortions while others did not. There was also no clear pattern among utilities, TSOs, ministries or regulators.

In conclusion, the rationales for interconnection and the opinions on capacity markets among experts in German, France and European institutions differed considerably. Moreover, there was no consensus among stakeholders about whether capacity mechanisms had to be homogenised given increased interconnection and what the effects would be. As a result, the effects of increased interconnection combined with a unilateral introduction of capacity markets are complex and disputed both in perceptions and effects. Integrating renewable energy was only one of many rationales for the introduction of a capacity market and increased interconnection. Therefore, a range of factors should be considered when deciding in favour of one or the other. A closer inspection via a complex energy model might reveal some insights into whether one could embrace polycentric governance and leave the introduction of capacity markets to Member States, while incentivising interconnection on a European level.

4.3. Empirically grounded electricity modelling

Finally, I examine the effects of a unilateral capacity market introduction on the policy trilemma for a total of 18 scenarios. I discuss model results on security of supply, wholesale power prices and welfare effects as well as carbon emissions in Germany and France. I primarily focus on the year 2030 to examine long-term results.

4.3.1. Security of supply

Base case, French government targets and German coal exit

In the base case, France will require 1.5, 6.5 and 15 GW of additional capacities in 2020, 25 and 30, respectively, to meet 3 hours loss of load expectation, primarily driven through the nuclear phase out. For the more pronounced nuclear phase out with intermittent renewable energy increase, France would require higher backup capacities of 7.0, 15.0 and 19.0 GW in 2020, 25 and 30. A German coal exit does not significantly affect French required capacities compared to the base case, with 2.5, 7.5 and 15.5 GW being required. As determined in the assessment last year (BMWi 2015), Germany seems not to be running into security of supply issues in the coming years. In the base scenario, the energy-only market will provide 15.0 GW and 7 GW more than needed in 2020 and 2025 to meet the 3 hours security of supply criterion. However, as mentioned in the interviews, in the long-term the energy-only market might not provide sufficient investments for back-up capacities with increasing renewables. In 2030, 3.5 and 4 GW are projected to be required in the base and French government target scenarios, which could be met by the strategic reserve. With a German coal exit, even 8.5 GW will likely be required to reach the security of supply criterion in Germany.

Interconnection

The increase of interconnector capacity does not materially affect French required capacities while it does benefit German security of supply in all scenarios. In order for France to meet 3 hours LOLE, the especially deep cases of unserved energy would have to be addressed. However, during these times, Germany has loss of load, too. Therefore, the additional interconnection in the high interconnection case does not help France regarding security of supply. For a graphical representation refer to Figure 10.

A further explanation for this result is the fact that demand in France and Germany in 2012,13, and 14 were correlated with a coefficient of 0.57 while intermittent renewable generation was only correlated with 0.47. Since France primarily requires the capacity market to meet their demand peaks from electric heating, it benefits less from an increase in interconnection than high intermittent renewables Germany with respect to spatial averaging.

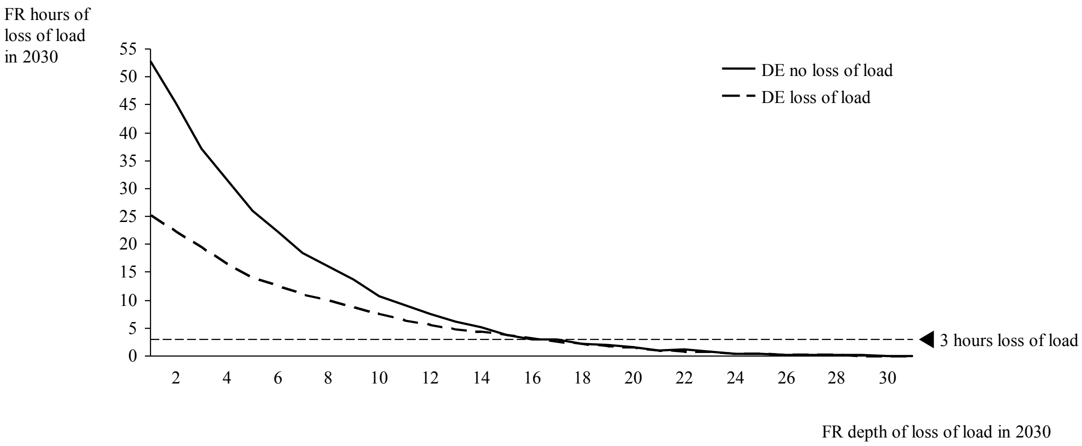

Figure 10 Comparison of French hours of loss of load and depth for times Germany experiencing loss of load to and not experiencing loss of load

Capacity market

In contrast to interconnection, the capacity market does materially affect security of supply both in Germany and France and there is evidence for a German free-riding effect. As the capacity market is calibrated such that it sets LOLE to 3 hours, the required capacity to meet this goal is approximately 0 GW in France. Additionally, there is evidence for German free riding on the French capacity market during system stress periods. The French capacity market will provide Germany with an additional 2 GW capacity margin to meet the 3 hours LOLE criterion in 2020. In 2030, France will provide 2.5 GW backup capacities. Similar results prevail for the French nuclear and higher benefits from the French capacity market in the German coal exit scenario, since the German capacity margin is made very tight through the coal exit.

While there is thus evidence for a German free-riding effect, Germany also seems to import a missing money problem in the long run. German gas plant capacities decreased with a French capacity market by approximately 0.5-1 GW by 2030. This is the case for all different generation capacity scenarios and is likely due to the increased provision of French peaking capacities during situations of high demand. As German plants are not allowed to explicitly participate in the French capacity market under the current proposal, they might not be able to recover their fixed costs, leading to their closure. In terms of magnitude, however, this effect is considerably smaller than the free-riding effect and the overall German installed capacity of 234 GW in 2030.

In conclusion, both German free-riding effect and missing money problem can be seen in the modelling, however, their effects are rather small compared to overall market size. Results can be seen in Table 5.

2030 capacity required (GW)	*Low IC*	*Base IC*	*High IC*
Base case			
FRA without CM	15.00	15.00	15.00
FRA with CM	0.00	0.00	0.00
DEU without CM	4.50	3.50	2.50
DEU with CM	3.00	1.00	0.00
French government targets			
FRA without CM	19.00	19.00	19.00
FRA with CM	0.00	0.00	0.00
DEU without CM	5.00	4.00	2.50
DEU with CM	4.00	1.50	-0.50
German coal exit			
FRA without CM	15.50	15.50	15.50
FRA with CM	0.00	0.00	0.00
DEU without CM	12.00	12.00	12.00
DEU with CM	9.00	8.50	8.50

Table 5 Capacity required to meet 3hrs loss of load expectation in 2030

4.3.2. Welfare effects

To examine arguments of economic efficiency, I compare prices and welfare effects for the different scenarios.

Prices

In the base case one can see that prices converge between France and Germany with increased interconnection. Furthermore, due to the capacity provided by the capacity market, price peaks become less in frequency and magnitudes resulting in generally lower prices by about 0.2 EUR/MWh in 2030 and similarly for previous years. One can see that with regards to this point, German wholesale prices decrease, too, suggesting a free-mover effect. This effect, however, is very small and significantly smaller than the French price decrease.

Similar effects prevail for the other cases, although they are generally larger. With the German coal exit, French prices with the capacity market decline by 1 EUR/MWh compared to without a capacity market, as French plants would benefit from higher price spikes in Germany when exporting. With increased French intermittent capacity and the stronger nuclear phase out, more capacity is incentivised by the capacity market. As a result, prices are even lower for this case. An overview of the results is provided in Table 6.

2030 Prices (EUR/MWh)	*Low IC*	*Base IC*	*High IC*
Base case			
FRA without CM	65.56	65.17	63.19
FRA with CM	65.23	64.96	61.68
DEU without CM	55.58	55.89	56.40
DEU with CM	55.32	55.80	56.25
French government targets			
FRA without CM	64.59	64.28	62.80
FRA with CM	64.31	63.48	61.38
DEU without CM	55.51	55.76	56.45
DEU with CM	55.59	55.65	56.18
German coal exit			
FRA without CM	68.90	68.62	68.00
FRA with CM	67.92	67.14	66.45
DEU without CM	60.20	60.43	60.93
DEU with CM	61.01	61.27	61.67

Table 6 Wholesale prices 2030

Welfare analyses

In order to assess effects comprehensively, two welfare analyses have been conducted to (1) compare the base case without capacity market to the base case with the capacity market, (2) compare the base case with capacity market with both high and base interconnection. Both analyses were conducted for the year 2030 to consider long-term effects. Although results were checked for robustness across other scenarios, they have to be interpreted with caution, especially with respect to the high lost load that is determined for France in 2030.

Both interconnection but especially the capacity market provide a surplus in overall social welfare in both countries. In the case of the capacity market the benefit is primarily driven by the benefit of avoided loss load both in France but also in Germany, as less capacity has to be provided by the strategic reserve. Moreover, the capacity market increases consumer rent while decreasing producer rent as price peaks become less frequent. This effect is smaller in Germany and overall considerably smaller in magnitude compared to the benefit of avoided lost load. Overall, I find that the yearly net social surplus due to the introduction of a capacity market for France and Germany are EUR 4.2 bn and 0.1 bn, respectively in 2030.

In the case of an interconnection increase, prices converge in both countries. Consequently, French consumers benefit from lower German wholesale prices while German producers benefit as they can produce more. The effects for German consumers and French producers are opposite, as expected. Moreover, Germany benefits from increased security of supply due to higher interconnection resulting in lower costs for their strategic reserve. In France, increased interconnection leads to a slight reduction of the cost of the capacity market as the expected profits for peaking plants increase, leading to lower bids. However, this does not materially alter net welfare, as it is primarily a redistribution from producers to consumers. As a result, overall social surplus is positive if the yearly depreciated and discounted cost of the interconnector is smaller than EUR 115 million, which is highly likely the case.

In conclusion, based on an analysis of 2030, for Germany the benefits from free-riding on the French capacity market are larger than the costs from decreased price peaks. Moreover, increased interconnection decreases the cost of the French capacity market and the cost of the German strategic reserve. Depending on interconnector costs, it might thus benefit the overall system. As a result, interconnection and unilateral introductions of capacity markets result in yearly welfare increases of approximately 5% of total system costs. Nevertheless, redistribution effects between countries are relatively small compared to within country redistribution. The results can be seen in Table 7.

2030 welfare changes (EUR)	*With vs without CM*	*High vs base IC given CM*
Germany		
Δ CS	47,226,978.33	-253,817,009.13
Δ PS	-90,138,477.05	15,389,522.39
Δ IC_{Rent}	2,884,535.71	46,807,936.90
Δ Cost of interconnector	0.00	-16,825,689.27

Δ Benefit from strategic reserve reduction	186,170,212.77	106,382,978.72
Δ Benefit from avoided lost load	0.00	0.00
Total	146,143,249.75	-102,062,260.38
France		
Δ CS	105,060,631.98	1,639,794,662.63
Δ PS	-777,184,198.93	-1,484,048,134.88
Δ IC_{Rent}	2,884,535.71	46,807,936.90
Δ Cost of interconnector	0.00	-16,825,689.27
Δ Cost of CM in France	-8,341,917,157.21	61,975,741.47
Δ Benefit of CM to existing producers	8,340,160,865.32	-61,940,313.33
Δ Benefit from avoided lost load	4,857,459,384.34	0.00
Total	4,186,464,061.20	185,764,203.52

Table 7 Changes in total welfare in 2030 for different base scenarios

4.3.3. CO_2 emission effects

The influence of increased interconnection and the introduction of capacity markets on CO_2 emissions is generally small, even with the introduction of efficient gas plants instead of demand side response or storage. In the base case in 2030, the introduction of the capacity market increases emissions approximately by 4.0 million tonnes of CO_2 in France while it decreases them in Germany by 1.2 million tonnes of CO_2. Moreover, increased interconnection raises CO_2 emissions in Germany while they are decreased in France. This is primarily due to increased exports of low cost but carbon intensive electricity from coal and lignite in Germany, resulting in an overall system emission increase of 16 million tonnes in the high interconnection case compared to the low interconnection case. This exemplifies the need to substantially and simultaneously increase low carbon energy sources while enhancing interconnection.

Similar patterns prevail for the French increased nuclear phase out and increase in intermittent renewables. Generation from nuclear is almost fully substituted with generation from intermittent renewables, resulting in no major CO_2 emission differences. The effect of a German coal exit on emissions is significantly larger than the introduction of a French capacity market or increased interconnection. Although French emissions increase by 7 Mt CO_2 due to increased utilisation of their gas plants, German emissions decrease by approximately 29 Mt CO_2 in 2030. For this case, there is also no clear pattern with respect to interconnection anymore, as both in Germany and France gas plants will be built with similar emissions. Therefore, total CO_2 emissions do not change much with increased interconnection.

Although capacity market and interconnection increase total emissions in 2030, primarily the capacity market enables the integration of intermittent renewables in Germany and France to some extent. The French capacity market, especially in combination with interconnection, almost enables Germany to meet its loss of load criterion of 3 hours loss of load despite an increase of 54 GW intermittent renewables between 2016 and 2030. In the base case, this leads to a decrease of total emissions of 73 Mt CO_2, a 22% decrease compared to 2016, while demand stays approximately flat. Of course, German backup capacities also enable the integration of these intermittent renewables, but the French capacity contributes a significant part. An overview of the findings can be found in Table 8.

2030 Emissions (Mt CO2)	*Low IC*	*Base IC*	*High IC*
Base case			
FRA without CM	25.220	24.130	23.920
FRA with CM	28.910	27.920	26.188
DEU without CM	257.013	261.200	273.611
DEU with CM	256.074	260.005	271.218
French government targets			
FRA without CM	25.262	24.789	22.799
FRA with CM	29.117	29.903	27.068
DEU without CM	257.073	261.490	271.503
DEU with CM	256.095	258.993	267.903
German coal exit			
FRA without CM	28.770	28.690	28.460
FRA with CM	35.100	34.506	35.331
DEU without CM	236.888	233.826	234.462
DEU with CM	232.400	231.400	234.288

Table 8 CO2 Emissions 2030

4.4. Discussion

I examine the question to what extent interconnection and capacity markets can be combined using theoretical economic analysis, stakeholder interviews as well as empirically grounded modelling focusing on the case of Germany and France. Here, I first compare and contrast results of the different methods with regards to the research questions and then draw wider implications with respect to polycentric governance, distributional fairness and integrating intermittent renewables.

Interconnection and capacity market as substitutes

I argue that given perfectly positive correlated demand and symmetrical markets that only differ with respect to their technology variable cost, interconnection provides benefits through a more efficient sharing of generation technologies. Additionally, the capacity market provides value by helping to avoid loss of load. Under these assumptions, if residual demand patterns are less than perfect positively correlated, interconnection also provides value by providing security of supply as well as reducing the capacity that has to be provided by the capacity market. However, as determined in the modelling part, given French plans to phase out nuclear plants in combination with high peak demand and intermittent renewables, there will be so much capacity needed that even highly ambitious interconnection expansion plans might not contribute substantially to meeting the French security of supply criterion. As a result, either interconnection plans need to be adjusted upward, which might be economically inefficient from an overall standpoint or the introduction of a capacity market becomes necessary.

Homogenisation of capacity mechanisms given interconnection

In the interviews, it was determined that perceptions and rationales of interconnection and capacity markets differed. Moreover, views concerning the question whether market designs had to be aligned given increased interconnection, were similarly disputed among stakeholders, due to the different specific problems a capacity mechanism or market sought to address, with intermittent renewables being only one of them. As determined in the modelling part, while redistribution effects within Germany and France are considerable, on a net basis both countries benefit from the unilateral introduction of a capacity market, even with increased interconnection. Therefore, the homogenisation of electricity market designs might not be necessary from an economic efficiency point of view.

The effects of interconnection and unilateral capacity markets

As determined in the interviews, there was large disagreement about the effects of a unilateral introduction of a capacity market in the case of Germany and France. While some expected small effects, others argued that it would lead to large market distortions. It is very difficult to predict and quantify these effects in advance, among others due to uncertainty about the cost of the capacity market. First, among others, shares of intermittent renewables, electric heating, interconnection expansion, and policies regarding existing backup capacities determine the size of the capacity market. Second, the price of the capacity market is largely determined by the costs of providing additional capacity, which is also highly uncertain. Moreover, although the Monte-Carlo analysis might reliably determine loss of load expectation considerable uncertainty regarding future capacity timelines also make it difficult to assess the avoided hours of lost load. Nevertheless, the modelling results indicate that overall capacity markets and interconnection results in net benefits, although further research is needed to comprehensively assess the effects for a longer timeframe and less loss of load. Similar studies suggest less hours of lost load (FTI 2016), but the assertion that capacity markets result in economic welfare increases is also found in overall studies (Hary et al. 2016). Moreover, free-riding effects of foreign capacities, however, perhaps due to the shorter time horizon, free-riding effects are considerably larger than the melt-off of existing foreign capacities. However, overall both effects are comparatively small compared to total system cost.

Policy implication 1: Promoting polycentric governance

Rationales with regards to capacity markets differed while increased interconnection were generally welcomed by all stakeholders. Moreover, as determined in the cost-benefit analysis, the overall net benefit of a unilateral capacity market introduction is positive for both countries. As a result, the governance with regards to interconnection and capacity markets can remain polycentric. Interconnection should be promoted at the European level to potentially overcome financial, political, economic and administrative barriers for example via a headline target of 10% and 15% (Puka & Szulecki 2014). In contrast, the introduction of a capacity market can remain up to national discretion, to address a country's specific issue with a well-calibrated capacity market. Nevertheless, rules for coordination should be specified and protocols for emergency situations determined (Mastropietro et al. 2015), as well as equity and distribution effects considered.

Policy implication 2: Considering equity issues

Both capacity market and increased interconnection result in redistributive effects both within as well as among interconnected countries. Even with a large capacity market, free-riding effects of Germany are, however, relatively small compared to the changes from increased interconnection (similarly to Gore et al. 2016). Moreover, the capacity market also leads to a considerable redistribution of wealth from consumers to producers. The benefit from increased avoided hours of lost load is larger than what consumers would have to pay for in the capacity market. However, this result might be influenced by the high number of hours with lost load. Nevertheless, there are equity issues, i.e. free-riding effects and the import of the missing money problem. It should therefore be carefully examined whether compensation payments would be required and how it would be made sure not to distort markets.

Policy implication 3: Promoting capacity markets to integrate intermittent renewables and CO2 emissions

Given plans of increased penetration of renewable energies in many European countries, it is crucial to resolve the potential security of supply and generation adequacy issues in order to legitimise the switch to intermittent renewables among the public. Given low capacity margins in the German coal exit scenario, increased interconnection does not materially improve the security of supply compared to the base case. However, reliable French gas plants provided by the capacity market do so, suggesting that the capacity market has a larger potential for integrating intermittent renewables than interconnection given current expansion plans. However, a more explicit modelling approach with more significant increases of intermittent renewables would be needed to further examine this recommendation. Finally, while both capacity market and especially interconnection increased overall emissions, these effects should be adjusted by promoting the participation of demand side response and storage in the capacity market as well as even larger shares of renewable energy.

4.5. Limitations

4.5.1. Modelling limitations

Limitations regarding assumptions

The study has several limitations regarding assumptions and data. The limitations of the theoretical economic analysis are similar to the limitations of the modelling results. First, the model assumes perfect competition, which might not fully describe the German and especially the French power market. While this might be a substantial limitation, the majority of other modelling studies in the area similarly assume perfect competition, especially after electricity markets have been liberalised in many countries (e.g. Lynch et al. 2012; Brancucci et al. 2013; Egerer et al. 2013; Burgholzer & Auer 2016). Second, I assume that OCGT and CCGT plants will provide a third and two thirds of the necessary capacity in the capacity market, respectively. Given that capacity prices will be determined yearly, there is high uncertainty regarding whether these plants will be built, especially given risk aversion in case of investment decisions (Fan et al. 2012), which I do not consider in the model. However, even if other technologies such as storage and demand side response were considered, results would primarily be driven by cost assumptions, which are highly uncertain and contested. Third, for limitations of time and scope, I primarily consider effects on CO_2 with respect to sustainability and prices with respect to welfare, while ignoring other effects, which might even be reliably priced. For example, I do not consider effects on biodiversity, other emissions or public opposition. For a detailed overview of the limitations of welfare focused cost-benefit analyses refer to Schmidt & Lilliestam (2015). However, based on the interviews, it seems that decision-making is primarily based on these dimensions. As a result, there are several assumptions, which might influence the reliability of the outcomes.

Limitations regarding scenarios

There are also some limitations regarding the selection of scenarios. Although I cover a range of policy scenarios, it will be uncertain which future state will materialise. Furthermore, I assume that electricity will still be traded in wholesale markets and the most cost-competitive renewables are still intermittent, which, however, seems likely given current projections. Moreover, uncertainties regarding the discount rate prevail, however, as effects in one year were analysed these should not be too large. The capacity market turns out to be larger than the change in increased interconnection, which might skew the results to some extent. However, this effect has been considered in the interpretation of the results. Finally, I do not consider 100% renewable scenarios due to the time horizon and the capability of the model.

Limitations regarding the model

In addition to limitations regarding the assumptions, there are also limitations concerning the model itself. First, for computational reasons, runs are based on 12 typical days during a particular year. Although this is a common approach in power modelling (e.g. Moest & Fichtner 2010; Spiecker & Weber 2014), this fact might be especially influential as peak events are examined. These usually only affect a few hours of the year. To consider this limitation, analyses regarding security of supply are done using a Monte-Carlo analysis to enclose extreme patterns. Additionally, some years and scenarios are additionally modelled on a full-year basis to ensure robustness. Results do not differ materially. Second, due to time constraints, French plants are not modelled endogenously and therefore no explicit capacity market model is implemented. However, given that the majority of French plants are primarily driven by policy decisions, e.g. coal phase out, nuclear phase out and renewables expansion, this should not necessarily be an issue. Nevertheless, I assume that efficient gas plants are primarily incentivised by the capacity market alone instead of a combination of wholesale and capacity market. This might likely overestimate the amount of capacity that is required to be delivered by the capacity market and likely be responsible for the high number of hours of lost load. Third, demand is not explicitly modelled but assumed as given based on a scenario by RTE. Given that French demand is especially determined by weather and climate which are projected to be changing due to climate change (RTE 2014a), I likely underestimate demand shocks. The combination of an energy model with a climate model might result in more accurate predictions; however, the overall effect of a unilateral capacity market introduction still seems to be described accurately. Fourth, the model does not model the electricity grid, including loop flows and congestion, which influences how much of interconnector flows is actually commercially usable. Although, the exact effects of future interconnection will thus be difficult to assess, the general tendencies of increased interconnection should not be affected. Fifth, for computational constraints, loss of load expectation is only determined for the years 2020, 2025 and 2030 and interpolated for the years in between, which might result in slight changes in the capacity timeline. In conclusion, results might to some extent be affected by limitations of the model, especially representative days, exogenous French capacities and capacity market.

4.5.2. Interview limitations

In addition to the limitations of the model, there are some limitations regarding the interviews. First, capacity markets and interconnectors are sometimes discussed in different parts of the organisations. For example, capacity markets are primarily the area of competence of DG COMP while interconnection is the competence of DG ENER within the European Commission. As a result, some interviewees had a more in-depth knowledge in one area. Second, sometimes audio recordings were not permitted and some interviews were conducted in German. Therefore, the analysis of four interviews had to be done based on notes and memory, which might introduce some biases. Third, more interviews were conducted with German stakeholders. However, this was due to the complexity of having four TSOs and several energy companies in the German electricity system, which was carefully controlled for, when analysing interviews. Finally, I use convenience sampling to select interviewees and these self-selected into participating. However, interviews were not conducted for statistical representativeness but to gain an understanding of different views on the issue. Self-selection ensured that participants were comfortable answering questions about their area of expertise. Although there are some limitations with regards to the interviews, these should not have affected the fundamental conclusions of the analysis.

5. Conclusion

I examine to what extent capacity markets and interconnection can be combined using a range of different methods, including theoretical economic analysis, semi-structured stakeholder interviews and empirically-grounded electricity system modelling. As the mitigation of climate change necessitates a substantial increase of intermittent renewables capacities, the interaction of capacity markets and interconnection is at the heart of this problem. This is the first study to systematically consider the integrated effects on welfare, emissions and security of supply; as well as taking stakeholder rationales and the aspect of substantial shares of intermittent renewables into consideration. First, I find that capacity markets and interconnection are theoretically substitutes for both ensuring security of supply given different residual demand patterns. However, in case of large capacity needs driven by a nuclear phase out combined with an increase in intermittent renewables, required interconnection capacities need to be considerably higher than current plans. Second, rationales with respect to interconnection differ while views on the necessity of capacity markets differ considerably between French and German stakeholders. As a result, no homogenisation of market designs might be desirable. Third, the capacity market in France increases overall economic welfare even with high interconnection, while resulting in large redistribution primarily within countries. Finally, the effect on overall emissions depends on the technologies being incentivised in the capacity market as well the generation mixes in interconnected countries, but benefits arise through enabling the integration of intermittent renewable energies. While posing considerable redistributional and political challenges, combined effects of interconnection and capacity market likely enable rather than inhibit the scale up intermittent renewables from an economic point of view.

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