SECURITY OF SUPPLY DURING THE ENERGY TRANSITION

THE ROLE OF CAPACITY MECHANISMS

Proefschrift

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Summary

Introduction

Energy sustainability is one of the most widely debated topics of the 21st century. The recently concluded UNFCCC Paris agreement has set us on a steeper trajectory towards de-carbonization of the energy system. On a day-to-day basis the impact of these sustainability policies is strongly experienced in the electricity sector. The push for clean energy has seen a rapid growth of renewables in the electricity supply mix. Although one would assume that the impact of these technologies is entirely positive, recent research indicates that there is reason for concern namely, regarding the security of supply. In this context, the concern is how renewable energy sources (RES) affect the business case of conventional power generation.

In response to these concerns, capacity mechanisms are being considered or have already been implemented by various member states of the EU. However, in a highly interconnected electricity system, such as the one in Europe, there appears to be a risk that the uncoordinated implementation of capacity mechanisms may cause unintended 'cross-border effects'.

This research explored the performance of various capacity mechanisms in the presence of a high share of RES generation. The performance criteria were the effectiveness of the capacity mechanisms in attaining the intended policy goals, their impact on the long-term development of electricity markets in the presence of a growing share of renewable sources in the supply mix and the cross-border effects caused by the implementation of these instruments in interconnected markets. This doctoral research addressed the following research question:

How to maintain security of supply during the transition to a low carbon energy system?

The research question was investigated using quantitative and qualitative methods. The quantitative analysis involved an agent-based modeling methodology, which was augmented by a qualitative survey study.

In this research, two capacity mechanisms, namely a strategic reserve and a capacity market, were modeled as extensions to the EMLab-Generation agent-based model. Furthermore, two variations of a capacity market were analyzed. The first was a yearly capacity market design based on the NYISO-ICAP and the second was a forward capacity market with long term contracts based on the UK capacity market design. A survey of experts on the US capacity markets balanced the modeling work with practical insights.

The research conducted in this doctoral thesis makes two scientific contributions. Firstly, the research contributes to extending our current knowledge about capacity mechanisms. Secondly, a new methodological approach for the analysis of capacity mechanisms is explored with the use of an agent-based model.

EMLab-Generation agent-based model

The EMLab-Generation agent-based model (ABM) has been augmented for this research by modeling a strategic reserve and two capacity market designs as model extensions. The EMLab-Generation agent-based model (ABM) was developed in order to model questions that arise from the heterogeneity of the European electricity sector and the interactions between different policy instruments. The model aids in providing qualitative insights into the simultaneous long-term impacts of different renewable energy, carbon emissions reduction and resource adequacy policies, and their interactions, on the electricity market.

In an agent based model actors are modeled as autonomous decision making software agents. The power generation companies are the central agents in this model. The power generation companies make decisions about the purchase of fuel for their power plants, bidding in the power markets, participating in capacity mechanisms, investments in new capacity and decommissioning of power plants.

The agent behavior is based on the principle of bounded rationality, i.e., the decisions made by the agents are limited by their current knowledge and their prediction of the future. Agents make decisions based on their interactions with each other and their understanding of their environment. The agents interact with each other and other agents via the electricity market and thereby bring about change in the state of the system. Consequently, the results from the model are an emergent property of the agent's interaction with each other and their environment, thus the results do not adhere to any optimum path. This allows us to study the evolution of the electricity market under conditions of uncertainty, imperfect information and non-equilibrium.

The EMLab-Generation is a model of two interconnected electricity markets, which allows for analysis of cross-border effects. The model also provides the functionality for conducting analysis on isolated electricity markets with no interconnections. The model allows the user to implement detailed representations of different capacity mechanism designs, thus allowing for the comparison of different capacity mechanism design options. The model provides the functionality to analyze scenarios with high renewable energy penetration in the supply mix.

Strategic Reserve

In Chapter 3 the effectiveness of a strategic reserve is investigated with respect to incentivizing adequate generation investment in an isolated electricity system without and with a strong growth in the portfolio share of intermittent or variable renewable energy sources (RES). The impact of the size and the dispatch price of the strategic reserve on reliability is studied by analyzing the performance of a strategic reserve under different dispatch price and volume combinations.

The strategic reserve design that is modeled in EMLab-Generation turns out to have a stabilizing effect on an electricity market in a reasonably cost-effective manner. Early investment incentives improve the supply ratio and therefore reduce shortages. Two problems with a strategic reserve have been found. First, there is a risk of extended periods of high average electricity prices if the reserve fails to attract sufficient investment. Second, the effectiveness of the reserve with respect to maintaining generation adequacy appears to decrease as the share of variable renewable energy grows. In this case, the reserve may need to be redesigned or replaced by an alternative capacity mechanism. Our long-term model of a strategic reserve also reveals what we describe as the dismantling paradox. If a reserve contains old units that should be dismantled, the presence of the reserve may cause undue life extension, whether these units are contracted in the reserve or not.

Yearly capacity market

In Chapter 4, the effectiveness of a yearly capacity market with and without a growing share of renewable energy sources is analyzed. The effectiveness of the capacity market under different demand growth scenarios and design considerations is also analyzed. The design of the yearly capacity market implemented in EMLab-Generation is based on the installed capacity market (ICAP) that is organized by the New York Independent System Operator (NYISO) in the United States of America.

The yearly capacity market design that is modeled in EMLab-Generation can provide generation adequacy effectively in the presence of a high share of renewable energy and a demand shock. The capacity market would mainly lead to more investment in low-cost peak generation units. In comparison to a strategic reserve, a capacity market appears to provide a more stable supply ratio, especially in the presence of a growing share of variable renewable energy sources. The capacity market appears to remain effective under different demand growth conditions.

Forward capacity market

In Chapter 5, the effectiveness of a forward capacity market (FCM) is analyzed in a system with a growing share of renewable energy. The FCM design modeled in EMLab-Generation is based on UK’s forward capacity market design that was implemented in 2014. The effectiveness of the capacity market under different demand growth scenarios and design considerations is also studied. In order to understand the impact of this policy design on the effectiveness of the capacity market, the FCM is compared with a yearly capacity market (YCM).

The model results indicate that the implementation of a forward capacity market leads to a substantial reduction in the overall cost to consumers as compared to a baseline energy-only market. The reason is that the capacity price in a forward capacity market is less volatile and slightly lower on average than in a yearly capacity market. Like the yearly capacity market, the forward capacity market increases investment in low-cost peak generation capacity as compared to an energy-only market. In case of a demand shock a FCM is effective in providing the necessary security of supply.

Cross-border effects of capacity mechanisms

In Chapter 6, the cross-border effects of implementing various capacity mechanisms in an interconnected power system are analyzed. The cross-policy effects due to implementation of dissimilar capacity mechanisms in two interconnected regions are also examined.

Interconnection with a neighboring zone does not affect the ability of a capacity market to reach its adequacy goals. The neighboring zone may experience a positive spillover in terms of adequacy and consequently free ride on the capacity market, but may also become import dependent. The free riding could cause an increase in cost to the consumers in the capacity market. Generators in the neighboring energy-only zone may be crowded out, in some cases to the extent that an investment cycle develops.

The model results indicate that a strategic reserve would also have a positive spillover effect on a neighboring energy-only market, both in terms of reduction in shortage hours and cost to consumers. The cost of a strategic reserve to the consumers who pay for it would increase with a free-riding neighboring region.

A capacity market could reduce the need for, but may also reduce the effectiveness of a strategic reserve implemented in an interconnected zone. However, a strategic reserve could reduce the crowding-out effect that is caused by the neighboring capacity market on its own market and thus lower the risk of investment cycles.

Expert survey on capacity mechanisms

In Chapter 7, a survey of experts on US capacity markets that was conducted in November 2014 is presented. The goal of this survey was to provide insight and advice to the EU with respect to selecting, designing, implementing and administering capacity markets in a highly interconnected electricity network, based on the experience with capacity markets in the United States.

In the survey, experts on the US capacity markets generally recommended the use of energy-only markets over capacity markets. If a capacity market were to be implemented in the EU, the respondents recommended consistent and transparent rules, common definitions for capacity products, remuneration of providers based on actual performance during conditions of scarcity, and the use of a sloping demand curve for capacity market clearing. The respondents did not view cross-border effects of capacity markets as a pressing concern in the US at present, although it was recognized as a potential future issue.

The key concerns about the US capacity markets that emerged from the survey were uncertainty regarding the availability of generation resources that clear the capacity market during scarcity hours, a mismatch of capacity auction time frames, opportunities to exercise market power, and regulatory uncertainty associated with changes to market rules. According to the survey respondents, capacity markets in the United States achieve their goals with respect to reliability, but they do so in an economically inefficient manner.

Conclusions and Policy Recommendations

In an electricity market with a growing share of renewables, some form of long-term incentive appears to be required to ensure security of supply. In an isolated system, both the strategic reserve and the capacity market designs modeled in EMLab-Generation would improve the adequacy levels in the system. However, a capacity market appears to perform better than a strategic reserve over the long term. The capacity market is also able to perform well in a scenario with a demand shock. However, a capacity market may not provide sufficient incentive for investment in nuclear power plants.

In the representation of an interconnected system in EMLab-Generation, both capacity mechanisms have a positive spillover on the neighboring energy-only markets in terms of adequacy. Thus, the neighboring markets would free ride on the capacity mechanisms, while generators in the neighboring region may be crowded out. In order to mitigate this risk, the region may choose to implement its own capacity mechanism.

The surveyed experts on the US capacity markets generally recommended the use of energy-only markets over capacity markets. The main concerns were the uncertainty caused by incremental changes to capacity market design and regulations. If a capacity market were to be implemented in the EU, the respondents recommended that policy makers should ensure minimal incremental changes to capacity market design and consistent regulations over time, in order to reduce regulatory risk. Cross-border effects of capacity markets are not viewed as a pressing concern in the US at present, but were recognized as a potential future issue.

According to the research carried out in this doctoral thesis, a capacity market would be the recommended capacity mechanism as compared to a strategic reserve. Policy makers in the EU are advised to ensure minimum changes to the capacity market design and rules after implementation. This would require the implementation of a comprehensive capacity market design that accounts for all foreseeable contingencies. However, capacity mechanisms such as capacity subscriptions and reliability contracts that were not included in this study, may also prove to be effective.

The results from this research also suggest that a sophisticated capacity market design may not necessarily be more effective. A yearly capacity market design may be able to accomplish the security of supply goals as well as a more complex forward capacity market. Therefore, policy makers are advised to keep capacity mechanism designs as simple as possible.

Over time, policy instruments such as capacity mechanisms become difficult to discontinue as market parties become dependent on remuneration from such mechanisms in their investment and decommissioning decisions. Hence, it is recommended that an exit strategy is developed in case the capacity mechanism needs to be discontinued sometime in the future.

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1. Introduction

1.1 Background

Energy sustainability is one of the most widely debated topics of the 21st century. The recently concluded UNFCCC Paris agreement has set us on a steeper trajectory towards de-carbonization of the energy system. On a day-to-day basis the impact of climate policies is strongly experienced in the electricity sector. The push for clean energy has seen a rapid growth of renewables in the electricity supply mix. Although one would assume that the impact of these technologies is entirely positive, recent research indicates that there is reason for concern namely, regarding the security of supply. In this context, the concern is how renewable energy sources (RES) affect the business case of conventional power generation.

The liberalization of the electricity sector resulted in vertical unbundling of different segments across the value chain and led to the creation of wholesale power markets. These are energy-only markets where power producers are compensated for the energy that they produce and not for their installed capacity (Hogan, 2005). The demand at any given point in time in the market is supplied by the most competitive technologies in terms of their marginal cost. The clearing price in the market is set by the most expensive capacity that is needed to satisfy the demand, which is determined by the merit order.

Due to the 'merit-order effect' caused by RES penetration (Sensfuß et al., 2008), the business case of conventional power generation is negatively affected. In the context of 'security of supply', the intermittent nature of RES raises concerns whether the market can function without depending on conventional capacity, especially during periods of high demand. These concerns can be addressed by implementing capacity mechanisms. Capacity mechanisms are policy instruments to ensure adequate investment in generation capacity. Sometime they are considered as measures that provide stability during the transition to a decarbonized electricity system.

The European Union (EU) has been at the forefront of the renewable revolution; hence the 'merit order effect' is more prominent in the EU electricity market. In response to the concerns related to the rising share of renewables, capacity mechanisms are being considered or have already been implemented by various member states of the European Union. In the EU, the decision on implementation of capacity mechanisms is left to the discretion of the member states. Although the overarching reason for implementation of capacity markets is supply adequacy, the design of these mechanisms is dictated by local requirements and constraints. E.g., the issues in Germany are the north-south grid constraints and the nuclear phase out while, in France the concern is the high demand during periods of extreme weather (in terms of temperature) (Coibion and Pickett, 2014). Hence across the EU, different capacity mechanism designs are implemented by member states.

In a highly interconnected system such as the continental European electricity system, there appears to be a risk that the uncoordinated implementation of capacity mechanisms may reduce economic efficiency and may even negatively affect the security of supply in neighboring systems leading to ‘cross-border effects’ (ACER, 2013; Regulatory Assistance Project, 2013).

1.2 Problem Description

In a complex system such as the EU electricity market, the interaction between various variables is difficult to predict. Particularly in the case of capacity mechanism, their impacts are uncertain. In order to understand these uncertainties, deeper insight into knowing the various capacity mechanism designs and reasons for their implementations is needed.

Capacity mechanisms can be classified based on the treatment of the two main economic variables, namely price and capacity (See Figure 1.1). These variables could either be determined by the market or by a central planning agency (Jaffe and Felder, 1996). The capacity mechanisms can be classified as ‘price based mechanisms’, when the price is determined administratively, while the investors determine the volume of capacity in which they would invest at the said price. In a ‘quantity based mechanisms’, the quantity of capacity that is required is set administratively, while the price is determined by the market(Hancher et al., 2015). Capacity mechanisms can also be classified as ‘targeted’ when the mechanisms focus on remunerating specific generation technologies or power plants and as ‘market-wide’ when the mechanism remunerates all type of capacity (Hancher et al., 2015).

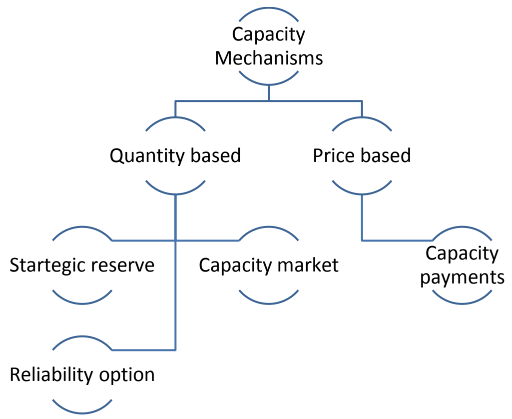

Figure 1.1: Classification of capacity mechanisms (ACER, 2013)

The rationale for implementing capacity mechanisms differs. Like in the case of the United States, capacity markets were implemented due to concerns regarding the ‘missing money problem’. The “missing money’ problem was first discussed by Shanker (2003) in the context of price caps in the US electricity markets. In an energy-only market with no price caps, the revenues from periods with scarcity provide sufficient opportunity for peak-load generation units with low number of operating hours to recover their costs. Imposing price caps would adversely affect the ability of these units to recover their costs. During scarcity conditions, a price cap would artificially lower the electricity price which would not reflect the true value of electricity during the scarcity period. This would lead to a reduction in the revenues for marginal or ‘peak’ generators that operate for a limited number of hours annually. Consequently these units would be unable to recoup their costs and become unprofitable. The missing money problem has also been explained in detail by (Cramton and Stoft, 2006; Hogan, 2005; Joskow, 2006a).

In the context of the EU, as mentioned the key concern is the penetration of renewable energy sources in the supply mix and the associated ‘merit order effect’ (Sensfuß et al., 2008). Firstly, Due to its low marginal cost of generation, RES based generation capacity is able to clear the market during all hours of its availability. As a consequence, it replaces a part of the more expensive thermal capacity from the merit order, thereby limiting the hours of operations per year for these thermal power plants. This in turn leads to a reduction in the opportunity for the thermal capacity to recover its costs. This would be aggravated as the share of renewable energy in the electricity supply mix increases. In theory, this should not affect their business case as long as scarcity prices are allowed to rise high enough. However, investment becomes riskier as their revenues come to depend increasingly on the infrequent occurrence of high scarcity prices. Secondly, the market clearing prices are also dampened, thereby leading to further reduction of revenues for thermal power plants. These effects along with fuel-price uncertainty, and uncertain demand growth, may lead to decommissioning of unprofitable thermal power plants and also a reduction in incentive to invest in new thermal power generation capacity.

The impact of renewables on the operating hours of thermal power plants, especially CCGT has already been observed and is expected to intensify (Meyer and Gore, 2015; Pöyry Management Consultant, 2011). Decommissioning of 21.3 GW of gas-based generation units was announced in 2013 in the EU (Caldecott and McDaniels, 2014; Meyer and Gore, 2015). More recently, plants in the Netherlands are being mothballed due to a combination of excess capacity and lower running hours due to the import of variable renewable energy from Germany (Straver, 2014). Wissen and Nicolosi (2007) contend that although much of the observed decommissioning was most likely due to other reasons, there is a possibility that some of these units would have remained operational in the absence of growth of renewable energy (Sensfuß et al., 2008). Similarly, Nicolosi and Fürsch (2009) and Bushnell (2010) expect a lower share of base-load power plants in the supply mix over the long run.

However, this thermal capacity is needed when the variable resources are not sufficiently available. Hence there is a legitimate concern regarding security of supply due to insufficient investment in new thermal capacity and decommissioning of existing unprofitable capacity.

Additionally, as mentioned earlier, in a highly interconnected electricity system such as the EU, there appears to be a risk of unintended cross-border effects. For the ease of understanding, the possible cross-border effects of capacity mechanisms are explained using an example. Consider two electricity market regions (A and B) that are interconnected. Region A implements a capacity mechanism while region B remains an energy only market. A strong investment incentive in region A may suppress investment in region B. At the same time, region B may free ride on the security of supply and lower prices, which are paid for by the consumers of region A. However, export of electricity from region A to B would depress power prices in region B by eliminating high prices spikes during scarcity. This spill over would have a negative effect on the revenues of peak generators in region B. Moreover, capacity mechanisms may change the distribution of wealth between consumers and producers in the entire interconnected system (Meyer and Gore, 2015).

In the EU, the following capacity mechanisms have been implemented by different member states. The UK has recently implemented a capacity market (DECC, 2014a) while France will do so in the near future (RTE, 2014). Belgium, Sweden and Finland make use of strategic reserves. Germany may implement a capacity reserve but decided against a full scale capacity market for the near future (BMWi, 2015). Capacity payments have been implemented by Portugal, Spain, Italy and Greece.

Since their implementation in the mid-2000s, capacity payments have been ineffective in reaching their policy objectives. Capacity payments have therefore been criticized as being a subsidy mechanism that does not guarantee reliability. The main issue while implementing a capacity payment is the difficulty in estimating the capacity payment level required to ensure adequate incentive for maintaining the required reserve margin (Batlle et al., 2007). Spain and Greece are undergoing a revamp of their capacity mechanism design while Portugal has suspended its capacity payments. Italy too is shifting to a capacity market (ACER, 2013). However, in Scandinavia the strategic reserve has been implemented and operated successfully. The proposed German capacity reserve design is conceptually close to a strategic reserve. Therefore in view of the current policy discourse in the EU, this doctoral thesis focuses on two capacity mechanisms namely, strategic reserve and capacity market.

A strategic reserve is defined as a set of power plants and/or interruptible demand contracts that are controlled by the transmission system operator. This contracted capacity is then deployed when the electricity price exceeds an administratively set 'reserve price' that is higher than the power plant's marginal cost of generation but below the value of lost load (*VOLL)* (De Vries, 2004; De Vries and Heijnen, 2006; Rodilla and Batlle, 2013). In theory, the artificial tightening of the supply due to the presence of a strategic reserve would attract investment in generation capacity before a physical shortage occurs. Consequently, the high price spikes that occur in periods of scarcity would be replaced by more frequent but also lower price spikes (capped at the reserve dispatch price (P_{SR})) (De Vries and Heijnen, 2008). This is similar to operating reserve pricing as described by Stoft (2002).

In a capacity market, consumers, or an agent on their behalf, are obligated to purchase capacity credits equivalent to the sum of their expected peak consumption plus a reserve margin (that is determined by the system operator or the regulator) through a process of auctions (ACER, 2013; Cramton and Ockenfels, 2012; Cramton et al., 2013; Creti and Fabra, 2003; Iychettira, 2013; Stoft, 2002; Wen et al., 2004). The additional revenues from the capacity market are intended to help (peaking) power plants to recover their fixed costs and thus mitigate the missing money problem (Joskow, 2008a, 2008b, 2006a; Shanker, 2003). A requirement for capacity is expected to provide a stronger and earlier investment signal than wholesale electricity prices and thus improve adequacy.

The study of such complex systems is difficult as market participants are bounded in their rationality due to the uncertainty about the future. As a result market outcomes are imperfect and cannot be studied under optimal circumstances. Therefore a comprehensive study of capacity mechanisms under conditions of uncertainty (fuel prices and demand growth) and imperfect investment behavior would provide a deeper insight into the market dynamics.

1.3 Research Question

The objective of this research is to explore the question of attaining long-term generation adequacy during the transition to a low carbon economy. The main issues of interest are the effectiveness of the capacity mechanisms in attaining the intended policy goals, their impact on the long-term development of electricity markets in the presence of an aggressive renewable policy and the cross-border effects caused by the implementation of these instruments in interconnected markets. Therefore, in this doctoral research the primary research question is:

How to maintain security of supply during the transition to a low carbon system?

The following secondary questions are discussed in this thesis:

1. How do the selected capacity mechanisms perform in an isolated system?
2. How do the selected capacity mechanisms perform in the presence of a high share of variable renewable energy sources?
3. What are the cross-border effects of these capacity mechanisms?

1.4 Methodology

The research questions in this thesis are investigated using quantitative and qualitative methods. The quantitative analysis is done using an agent-based modeling methodology which is augmented by a qualitative survey study.

In the context of electricity market modeling, agent-based modeling is a relatively new methodology. This approach has so far been applied to the study of short-term electricity markets as described by Guerci et al., (2010). A detailed literature review on the use of ABM based wholesale electricity markets has been conducted by Weidlich and Veit, (2008). Agent based modeling (ABM) is a bottom up approach in which actors are modeled as autonomous decision making software agents (Chappin, 2011; Dam et al., 2013; Farmer and Foley, 2009). The behavior of an agent is based on programmed decision rules. These decision rules can be different for each agent thus providing the flexibility to make the agent behavior heterogeneous. The results from these simulations emerge from the agents' interaction with each other and their environment. An example is the 'power generation companies' in EMLab-Generation. The power producers are agents that make decisions regarding investments in new generation capacity, dismantling of old power plants and dispatch of their capacity. The power producers interact with each other via the electricity market, thereby indirectly impacting each other's decision making over the long term (De Vries et al., 2013).

A key advantage of this approach is that it is not necessary to make assumptions about the reaction of the system as a whole to policy changes, as the system-level performance is a resultant of all agents' actions (Chappin, 2011). Therefore, assumptions are made only at the level of the agents (De Vries et al., 2013). Other advantages of ABM that have been presented in the literature are flexibility, modularity and possibility of parallel execution (Helbing, 2012). In ABM, parameters such as heterogeneity, spatiotemporal variability, and fluctuations can be taken into consideration (Helbing, 2012). ABM can be used to model any complex system closely and this complexity can be handled with relative ease. ABM provides allowance for relaxing certain assumptions of the neoclassical economic theory. Although ABM has many advantages, due to the exploratory nature of the agent-based modelling technique, traditional validation processes cannot be applied, making validation of agent-based models challenging (Louie and Carley, 2008). The EMLab-Generation agent-based model has been utilized for this research by modeling a strategic reserve and two capacity market designs as model extensions. EMLab-Generation has been under development at the Delft University of Technology since 2010. It has been developed for the purpose of analyzing long-term impacts of different renewable energy, carbon emissions, and resource adequacy policies and their interactions as "what-if" scenarios rather than forecasts or optimizations.

The EMLab-Generation is a model of two interconnected electricity markets thus allowing for the analysis of cross-border effects. The model also provides the functionality for conducting analysis on isolated electricity markets with no interconnections. The main agents in the model are the power producers that make short-term decisions regarding bidding in the electricity market and long-term decisions regarding investment in new capacity and dismantling of existing power plants. Thus the impact of policy interventions on the evolution of the market can be studied. The model allows the user to implement detailed representations of different capacity mechanism designs, thus providing an advantage while comparing different capacity mechanism design options. The model provides the functionality of introducing renewable policy, therefore enabling the analysis of scenarios with high renewable penetration. A key advantage of EMLab-Generation is that its modular nature allows the user to run a wide variety of scenario combinations. The uncertainty with regards to demand growth and fuel prices is accounted for by use of the Monte Carlo method. As the objective of the analysis in this thesis is to understand, the evolution of the electricity market over the long-term, the model simulates several decades in one-year time steps.

A survey of experts on the US capacity market was also conducted as part of this research. Wholesale electricity markets in the northeast United States have, over a decade of experience in implementing and operating capacity markets. The goal of this survey was to provide insight and advice to the EU with respect to selecting, designing, implementing and administering capacity markets in a highly interconnected electricity network, based on the experience with capacity markets in the United States. This compliments the modeling based study conducted in the remainder of this thesis and therefore adds to the robustness of the overall research conclusions.

1.5 Scientific Contribution

The research conducted in this doctoral thesis makes two scientific contributions. Firstly, the research extends our current knowledge about capacity mechanisms. Secondly, a new methodological approach for the analysis of capacity mechanisms is explored with the use of an agent-based model.

Capacity mechanisms are being implemented in the EU to ensure security of supply. Concerns about the effectiveness and impact of these mechanisms on the electricity market are a subject of much debate. This is reflected in the current literature on this topic by ACER, (2013); Caldecott and McDaniels, (2014); Finon, 2013; Mastropietro et al., (2015); SWECO, (2014). Two key concerns have been identified from the EU perspective. The first one is the ability of the mechanisms to reach their policy goals in a system with a large penetration of RES. The second one is concerned with the cross-border effects these mechanisms in a highly interconnected system. However, in a unique electricity market such as the EU, the legitimacy of these concerns is still unknown and thus a knowledge gap exists. In this doctoral thesis, the impact of capacity mechanisms on the long-term development of an interconnected electricity market with a high penetration of RES is studied. Thus this research contributes towards extending our current understanding of capacity mechanisms.

Various models have been used to study generation investment in the electricity market but do not consider capacity mechanisms in their analysis. (Boomsma et al., 2012) and (Fuss et al., 2012) use a real option approach in to study investment in renewable generation capacity under uncertainty. (Hobbs, 1995) use a mixed integer linear programming approach to study generation investment under perfect conditions. (Eager et al., 2012) use a system dynamics approach to study investment in thermal generation capacity in markets with high wind penetration. In this model, the investment decision are based on net present value and a value at risk criterion to account for uncertainty. (Bunn and Oliveira, 2008) use an agent-based computational model that is based on game theory to study the impact of market interventions on the strategic evolution of electricity markets. (Powell et al., 2012) present an approximate dynamic programming model to study long-term generation investment under uncertainty. (Botterud et al., 2002) use a dynamic simulation model to analyze investment under uncertainty over the long-term. None of these studies, however, considered the impact of a capacity mechanism on generation investment. However, agent-based modeling approach has not yet been widely used for such research, an exception being Ringler et al. (2014).

In the current literature the use of models for analyzing capacity mechanisms has been limited. (Hach et al., 2015) utilize a system dynamics approach to study the effect of capacity markets on investment in generation capacity in the UK. Similarly, (Cepeda and Finon, 2013) use a system dynamics approach to analyze impact of a forward capacity market on investment decisions in presence of a large-scale wind power development. As system dynamics is a top-down approach, (Dam et al., 2013) these studies ignore the impact of interaction between different market participants on the overall development of the system. (Mastropietro et al., 2016) use an optimization model to analyze the impact of explicit penalties on the reliability option contracts auction. (Meyer and Gore, 2015) use a game-theoretical approach to study the cross-border effects of capacity mechanisms on consumer and producer surplus. (Gore et al., 2016) use an optimization model to study the short-term cross border effects of capacity markets on the Finnish and the Russian markets. An optimization approach is used by (Doorman et al., 2007) to study the impact of different capacity mechanisms on generation adequacy. (Elberg, 2014) uses an equilibrium model for the analysis of cross-border effects of capacity mechanisms namely: strategic reserve and capacity payment on investment incentive. (Dahlan and Kirschen, 2014) and (Audun Botterud, n.d.) study generation investment in electricity market using an optimization approach. (Ehrenmann and Smeers, 2011) study impact of risk on capacity expansion using a stochastic equilibrium model. In this model investment decisions are made based on the level of risk aversion of the investor. The risk aversion is modeled using an conditional value at risk (CVaR) approach.

In existing models, capacity mechanisms are modeled with low granularity, which makes it difficult to understand the operational dynamics of these policy constructs and to compare different capacity mechanism designs. Secondly, none of the reviewed studies considered the combined impact of uncertainty, myopic investment (boundedly rational investment behavior) and path dependence on the development over time of an electricity market with a capacity mechanism.. However, in reality, the investors' ability to make decisions is bounded by their rationality i.e. their current level of information and predictions of the future. Such behavior may lead to suboptimal generation investments and may also affect the effectiveness of capacity mechanisms in reaching their policy goals. The use of an agent-based modeling approach allows us to study the development of the electricity market under imperfect conditions and uncertainty. Moreover the use of EMLab-Generation allows higher granularity in modeling different capacity market designs. Thus this work extends the research on use of ABM as a tool for analyzing impact of policies (especially capacity mechanisms) on the long-term development of electricity markets.

1.6 Thesis structure

Chapter 2: In this chapter the ***EMLab-Generation*** agent-based model is described. This provides a basis for the research presented in this thesis. Various capacity mechanisms are modeled as extensions to the existing EMLab-Generation model.

Chapter 3: In this chapter the effectiveness of a ***strategic reserve*** in an isolated system under varying conditions is analyzed. This chapter aids in answering sub-question 1 and 2.

Chapter 4: In this chapter the effectiveness of a ***yearly capacity market*** (based on the NYISO-ICAP) in an isolated system under varying conditions is analyzed. This chapter aids in answering sub-question 1 and 2.

Chapter 5: In this chapter the effectiveness of a ***forward capacity market*** with long-term contracts based on the UK capacity market design is presented. This chapter aids in answering sub-question 1 and 2.

Chapter 6: In this chapter an analysis of the ***cross-border effects*** of implementing a capacity market and also that of a strategic reserve is presented. This aids in answering sub-question 3.

Chapter 7: In this chapter a ***survey*** of experts on the US capacity markets with an aim of providing insights for the EU is presented. This chapter aids in answering research sub-question: 1, 2 and 3.

Chapter 8: In this chapter the main ***conclusions*** based on the entire research are presented. This chapter provides an answer for the main research question.

2. Model description

2.1 Overview

In this chapter, various aspects of the EMLab-Generation agent-based model are described. This is intended to provide the reader a basis for understanding the model and the research that is presented in the following chapters of this thesis. The detailed description of various model (capacity mechanism) extensions developed specifically for this research is presented in the relevant chapters.

The EMLab-Generation agent-based model (ABM) was developed in order to model questions that arise from the heterogeneity of the European electricity sector and the interactions between different policy instruments (De Vries et al., 2013; Richstein et al., 2015a, 2015b, 2014a). The model provides insight in the simultaneous long-term impacts of different renewable energy, carbon emissions reduction and resource adequacy policies, and their interactions, on the electricity market.

In reality, market participants make investment decisions based on imperfect information, leading to suboptimal investment outcomes. This could also have an adverse influence on the effectiveness of the various implemented polices in reaching their goals. In EMLab-Generation, decision making of agents is modeled based on the principle of bounded rationality. This allow us to test the robustness of various polices under suboptimal conditions.

Power generation companies are the central agents in this model. The behavior of the agents is based on the principle of bounded rationality (as described by Simon, (1986)), i.e., the decisions made by the agents are limited by their current knowledge and their limited understanding of the future. The agents interact with each other and other agents via the electricity market and thereby bring about change in the state of the system. Consequently, the results from the model are do not adhere to an optimal pathway and the model is typically not in a long-term equilibrium. Therefore, the model allows us to study the evolution of the electricity market under conditions of uncertainty, imperfect information and non-equilibrium.

In the short term, the power generation companies make decisions about bidding in the power market. Their long-term decisions concern investments in new capacity and decommissioning of power plants.

On the demand side, a single agent procures electricity on the behalf of all consumers. The aggregated demand is represented in the form of a stylized load duration curve that is described later in this chapter. The demand is dependent upon the initial scenario settings and the demand growth trend.

The main external drivers for change in this model are the fuel prices, electricity demand growth scenarios and policy instruments such as capacity mechanisms. The main outputs are investment behavior and its impact on electricity prices, generator cost recovery, fuel consumption, evolution of the supply-mix and system reliability.

The uncertainty regarding fuel prices and demand growth is represented by running each scenario 120 times according to the Monte Carlo method. The scenarios are run with the same starting conditions but with different fuel-price and demand-growth projections. The year-on-year fuel prices growth and demand growth trends are modeled stochastically using a triangular trend distribution, which is a mean reverting distribution. The upper and lower boundaries for the triangular distribution along with the average growth rate are user-defined values. The advantage of the triangular trend distribution is that, if the realization for a particular year is above average then it is probable that it would remain above average in the next year as well and vice versa in a below average case. Thus the distribution is able to simulate multi-year swings like those observed in reality (De Vries et al., 2013).

The model provides the functionality for conducting an analysis of an isolated electricity market as well as an interconnected electricity system. The representation of an interconnected system is limited to two zones with an interconnector. As the objective of this thesis is to understand the evolution of the electricity market over the long-term, all scenarios consist of 40 time steps, each of which represents one year.

The overview of the model activities during a time step is presented in a flowchart in Figure 2.1. At the start of each time step the power generation companies make annual loan repayments (if any) for their set power plants. In the next step power generation companies submit price-volume bids to the electricity market for all available power plants. This is followed by electricity market clearing. Once the market is cleared, the power generation companies purchase fuel for their power plants, pay for the operation and maintenance costs of all their power plants and receive payment for the energy sold on the electricity market. In the last step power generation companies make decisions regarding investment in new capacity and dismantling of existing power plants.

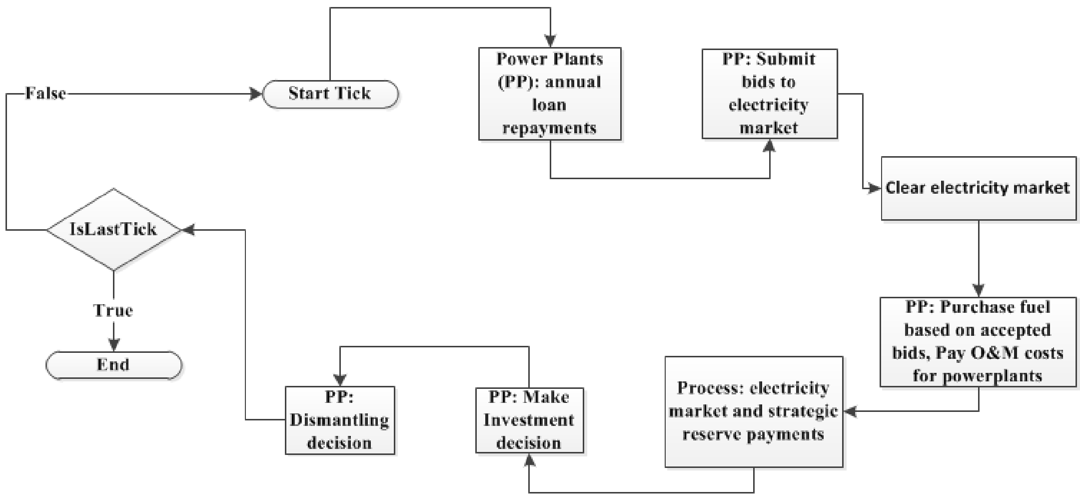

Figure 2.1: Stylized flowchart of the model activities during a time step

The EMLab-Generation agent-based model has been under development at the Energy and Industry section of the Delft University of Technology since 2010. The model is open source and available for download on its website[1]. The model has been coded using Java and functions within the AgentSpring framework (Chmieliauskas et al., 2012). AgentSpring is an

[1] http://emlab.tudelft.nl/

open source framework that utilizes a graph-database (consisting of nodes and edges) to capture the state of the system that is modeled. Graph-databases are described in detail in literature (Eifrem, 2009). Input scenarios in this model are made in Extensible Markup Language (*XML)* with additional functionality of using Comma Separated Value (*CSV)* file format for inputs that are in the form of trends.

The EMLab-Generation model has been verified and validated extensively. Model verification can be defined as the process of ensuring that the model has been implemented without errors, while validation tests if the model depicts reality accurately enough (Dam et al., 2013). The model verification was conducted using Junit[2] tests. These tests allow the programmer to test independently, different methods implemented in the model. In these tests, the programmer provides a set of input values for which the expected output is known. The output from the model for these input values is compared with the expected output. Various sub-modules of EMLab-Generation were tested[3] using this approach.

Due to the exploratory nature of the agent-based modelling technique, traditional validation processes cannot be applied, making validation challenging (Louie and Carley, 2008). For EMLab-Generation, tests used in system dynamics (Barlas, 1996) were used throughout the development of the model for the purpose of validation. This approach for validating agent-based models has earlier been used by Chappin, (2011). A detailed description of model verification and validation has been presented in Richstein, (2015).

A detailed description of EMLab-Generation has been presented in various reports (De Vries et al., 2013), articles (Bhagwat et al., 2016d; Richstein et al., 2015a, 2015b, 2014b) and also in an earlier doctoral thesis (Richstein, 2015). In the next section the structure of the model is described in detail followed by the input assumptions, model outcomes and model limitations.

2.2 Model structure

2.2.1 Demand

As mentioned earlier, in this model a single agent procures electricity on the behalf of all consumers. Electricity demand is represented in the form of a step-wise abstraction of a load-duration curve. In this approach, empirical load data is approximated into a step function consisting of segments with variable length in hours (see Figure 2). Thus each segment of the load duration curve has an assigned load value and a time duration, which is set as part of the initial input scenario. In each time step of the simulation, the load value for all segments is updated based on the exogenous demand growth rate. These segments have also been called “load blocks” or “load levels” in literature (Wogrin et al., 2014).

This approach for representing demand in electricity market models has been utilized for power system modeling since the 1950s, especially for medium and long-term models (Wogrin et al., 2014). The most important advantage of using this approach is that it allows for a shorter run time, enabling a larger number of simulations within a practical time frame

[2] http://junit.org/
[3] https://github.com/EMLab/emlab-generation/tree/develop/emlab-generation/src/test

(Richstein et al., 2014a). However, due to the loss of temporal relationship between load hours, short term dynamics such as ramping constraints and unplanned shutdowns cannot be modelled (Wogrin et al., 2014).

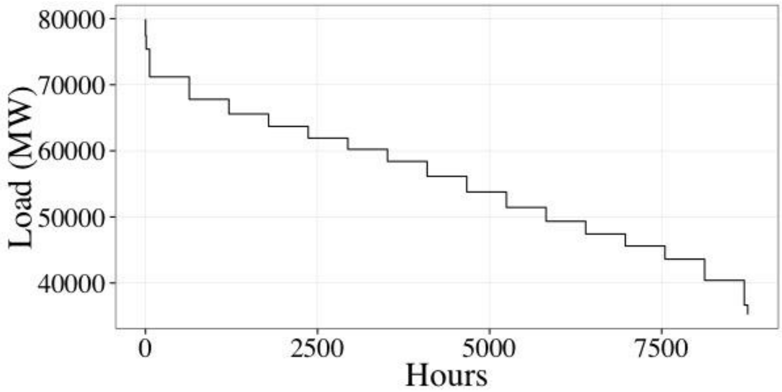

Figure 2.2: Example of a load-duration curve in EMLab-Generation for one country.

2.2.2 Electricity market clearing

The electricity market is modeled as an abstraction of an hourly power system (Richstein et al., 2014a). Within a one-year time step, the electricity market is cleared for each segment of the load-duration curve. Therefore the segment-clearing price is considered as the electricity price for the corresponding hours of the particular segment. In this model the load duration curve is divided into 20 segments. When the model is run in a two-zone configuration, each zone has its own separate load duration curve.

The power generation companies create price-volume bid pairs, for each power plant, for each segment of the load-duration curve. The power generation companies bid their power plants into the market at their marginal cost of generation, which is determined solely by the fuel costs. The volume component of the bid is based on the capacity of the power plant that is available in the given segment. The supply curve for each segment is constructed by sorting the bids in ascending order by price (merit order). The electricity market is cleared at the point where demand and supply intersect. The highest accepted bid sets the electricity market-clearing price for that segment of the market. If demand exceeds supply, the clearing price is set at the value of lost load (*VOLL*).

In the two-zone configuration, the market clearing algorithm that is described above, is run together for both zones assuming that there is no congestion between the zones. This results in a single price for both zones. If the interconnector is congested (i.e. the flow over the interconnector exceeds the interconnector capacity) the two markets are cleared separately (market splitting). In the zone that exports electricity, the demand is increased up to the level where the interconnector is completely utilized. The demand in the importing zone is reduced by the same amount. As a result the market-clearing prices for the given segment in the two zones are based on the modified demand values.

2.2.3 Generation technologies

In this model, there are 14 power-plant technology options available to a generator. However, the model does allow the functionality of adding new power plant technologies.

The future development of these technologies is modeled as a gradual decrease in costs and improvement in operational parameters, such as efficiency. The attributes of the power plants, such as fuel efficiencies, investment costs, operation and maintenance costs, and technological learning, are based on data from the IEA World Energy Outlook 2011, New Policies Scenario (IEA, 2011).

The intermittency of renewables is a short-term effect, which is difficult to implement in a long-term model such as EMLab-Generation, where demand is represented using an load duration curve. In this model, intermittency is approximated by varying the contribution of these technologies (availability as percentage of installed capacity) in different segments of the load-duration function. The segment-dependent availability is varied linearly from a large contribution to the base segments, to a very small contribution to the highest peak segment. The modeling of intermittency in EMLab-Generation is also described in De Vries et al., (2013); Richstein et al., (2015a, 2015b, 2014).

2.2.4 Investment algorithm

The investment behavior of the power generation companies is based on the assumption that investors continue to invest up to the point that it is no longer profitable. In this model, power generation companies invest only in their own electricity markets thus entry into a new market is not considered.

All investments are financed using a combination of debt and equity. The power generation company considers investment in a new power plant only if it has sufficient cash on hand to finance the necessary equity. The power generation companies invest the equity from their cash balance, based on an user defined expected rate of return on equity. A bank finances the debt at a user-defined interest rate. The debt is repaid as equal annual installments over the depreciation period for the power plant.

Power generation companies make investment decisions sequentially in an iterative process. The investment decision of each power generation company affects the investment decision of the next power generation company by changing its forecast of available capacity (we assume that power generation companies have full information about investment decisions that have already been made by competitors). This iterative process stops when no participant is willing to invest further. In order to prevent a bias towards any particular agent, the sequence of power generation companies is determined randomly in every time step.

During each investment round the power generation company compares the outcomes of investing in different power generation technology options available. At the start of each investment round, the power generation company makes a forecast of the future demand and fuel prices at a point of time in the future (reference year) based on past market data. The expected fuel prices are used to calculate the marginal variable costs of all power plants that are expected to be available in the reference year. These may be new power plants that have been announced or existing power plants that are within their expected life span in the reference year. The future electricity price for each segment is estimated by creating a merit order of the available power plants for each segment of the load duration curve.

The investor calculates the expected cash flow in the reference year for a power plant of each power generation technology under consideration. The expected cash flow is calculated by subtracting the fixed costs of the given power plant from its expected electricity market earnings. The expected earnings from the electricity market are calculated based on the power plant's expected running hours, the electricity prices and the variable costs (calculated based on expected fuel prices) in those hours of the reference year. The expected running hours of a power plant are calculated by comparing the expected electricity prices for each segment and the expected variable cost of the power plant under consideration. If the variable cost is lower than the electricity price, the power plant is assumed to have cleared the market in that segment. Therefore the power plant is assumed to have run for all hours of the given segment.

The expected cash flow value for each power plant under consideration is used to calculate the specific net present value (*NPV*) per MW, over the construction period and the power plant's expected service period. A weighted average cost of capital (*WACC*) is used as the interest for the *NPV* calculation. The power generation company invests in the power generation technology with the highest positive specific *NPV*. If all *NPVs* are negative then no investment is made. The investment algorithm is presented in a flowchart in Figure 2.3.

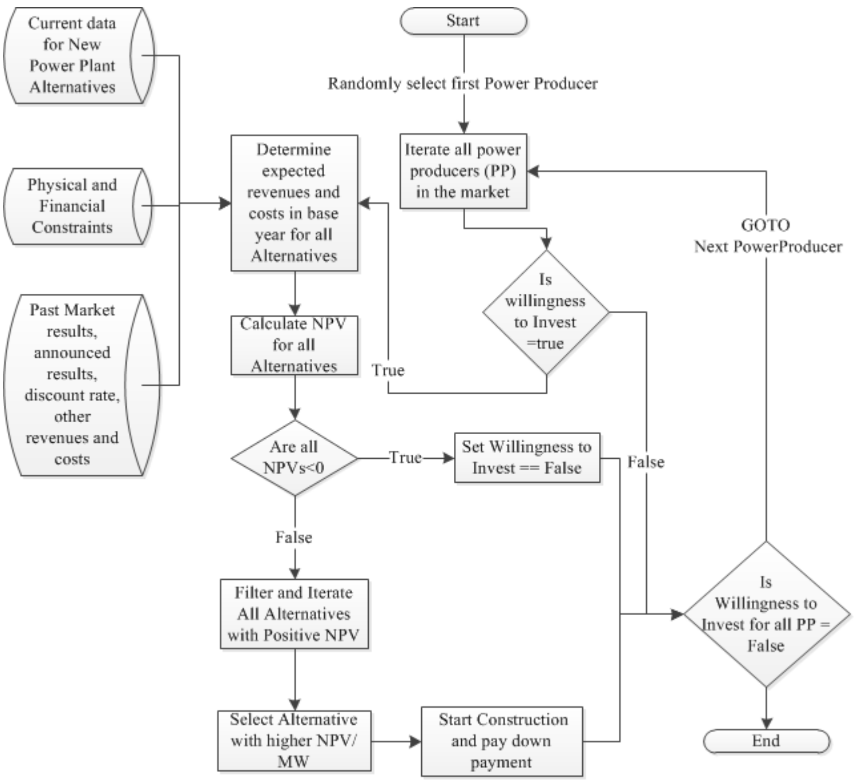

Figure 2.3: Stylized flowchart of the investment algorithm.

2.2.5 Decommissioning of power plants

While making decisions regarding decommissioning of existing power plants, power generation companies have to consider various factors such as age, policy and profitability. This makes modeling of power plant decommissioning decisions extremely complicated. EMLab-Generation offers the user two alternative dismantling algorithms. The first is a simple age-based dismantling algorithm in which power plants that are past their operational age limit are dismantled.

The second option takes into account the past and expected future profitability of the power plant while making the dismantling decision. In this thesis, the second type of dismantling algorithm is utilized. The power generation companies base their dismantling decisions mainly on the operational profitability of each power plant. In each time step, the power generation companies iterate through their set of power plants in order to make decommissioning decisions. For each power plant, the aggregated cash flow over the previous years is calculated. The time horizon (in years) for this look back is a user-defined value. If the cash flow of the power plant is negative, the power generation company makes a forecast of the cash flow for the coming year. If this forecasted cash flow is also negative, the power plant is decommissioned. In order to simulate the rising costs of old power plants, the operation and maintenance costs of power plants that are active beyond their operational age are increased year-on-year. This ensures that all old power plants are eventually dismantled (depending on market conditions).

2.2.6 Renewable energy policy

The development of renewable electricity generation is implemented as investment by a renewable ‘target investor’. If investment in renewable energy source (RES) based capacity by the competitive power generation companies is lower than the government target, the target investor will invest in additional RES capacity in order to meet the target even to the extent that the investor does not recover its costs in the market. This simulates the current subsidy-driven development of renewable energy sources.

2.3 Model inputs

At the start of the simulation, various parameters are required to be defined by the user. These parameters are set in the scenario file. Values of scenario inputs that remain common to all chapters are presented in this section while input values that change or are specific for a certain analysis are presented in the particular chapter.

The user defines the time horizon of the model in years, the number of electricity markets (limited to two nodes), the value of lost load (in €/MWh) for each electricity market, the size of the interconnector (in MW) and the number of power generation companies that operate in the model. In all scenarios used for this research the time horizon is set at 40 years and the value of lost load is 2000 €/MWh.

The parameters specified for each power generation company are - the look-forward period (to determine the ‘reference year’ for the *NPV* calculation), the look-back period for making forecasts in the investment algorithm, the look-back period for dismantling, equity interest rate, loan interest rate, and equity to debt ratio. In the scenarios used for this research, power generation companies finance 30% of the investment using the equity with an expected return on equity of 12% and 70% is financed by debt at an interest rate of 9%. In the investment algorithm, power generation companies use a look-forward period of 7 years, while the lookback for forecasting is set at 5 years. In the case of dismantling the look-back period is 4 years.

The initial power plant portfolio is defined either by setting the share (in percentage) of different technologies in the installed capacity of the market (and the model allocates an identical power plant portfolio to each power generation company) or by using a comma separated value (*CSV)* file with a list of power plants for each power generation company.

For every power generation technology, the user defines power plant capacity, depreciation time, construction time, expected lifetime, fuel type, peak and base load availability, fixed operation and maintenance costs, efficiency and capital costs. summarizes the assumptions regarding the power generation technologies. A *CSV* file is used for setting the cost trends of various fuels (See Appendix A).

Table 2.1: Assumptions for power generation technologies

Technology	Capacity [MW]	Construction time [Years]	Permit time [Years]	Technical lifetime [Years]	Depreciation time [Years]	Minimum Running hours	Base Availability [%]	Peak Availability [%]	Fuels
Coal	758	4	1	50	20	5000	1	1	Coal, Biomass (10%)
CCGT	776	2	1	40	15	0	1	1	Gas
OCGT	150	0.5	0.5	30	15	0	1	1	Gas
Nuclear	1000	7	2	40	25	5000	1	1	Uranium
IGCC	758	4	1	50	20	0	1	1	Coal, Biomass (10%)
Wind Offshore	600	2	1	25	15	0	0.6	0.07	-
PV	100	2	1	25	15	0	0.2	0.04	-
Wind Onshore	600	1	1	25	15	0	0.4	0.05	-
Biomass	500	3	1	40	15	5000	1	1	Biomass
CCGTCCS	600	3	1	40	15	0	1	1	Gas
CoalCCS	600	4	1	50	20	5000	1	1	Coal, Biomass (10%)
Lignite	1000	5	1	50	20	5000	1	1	Lignite
Biogas	500	3	1	40	15	0	1	1	Biomass
IGCCCCS	600	4	1	50	20	0	1	1	Coal, Biomass (10%)

On the demand side, the number of segments (20 segments are used for this research), the length of each segment in hours and the initial load value (in *MW*) for each segment of the load duration curve is set in the initial scenario. A *CSV* file is used for setting the year-on-year demand growth trend. The initial values for the various segments of the load duration curve are presented in the Appendix B.

In the scenarios used for this research, the coal and gas prices trends are based on fossil-fuel scenarios published by the UK Department of Energy and Climate Change (2012). The biomass cost trends are based on Faaij (2006) and those for lignite are based on Konstantin (2009).

2.4 Model outcomes and key indicators

The key data (e.g. electricity prices, producer cash balance, total annual power generation etc.) presented by the model that is required for analysis can be found and stored using queries written in cypher or gremlin programming languages. A query locates a particular data point in the graph database for every time step of the model. A detailed description and example of querying is presented in (De Vries et al., 2013). The queried data is stored in text files, which can be converted into *CSV* files at the end of the model run.

In order to analyze the impact of capacity mechanism, the data from the model is converted into indicators. These indicator should be such that they are easy to understand and at the same time provide maximum information. R-Studio and Microsoft Excel are used to generate the key indicators and the necessary graphical interpretation from the raw data. The following indicators are used in the analysis of the model results in this thesis:

- The average electricity price (€/MWh): the average electricity price over an entire run.
- Shortage hours (hours/year): the number of hours per year with scarcity prices, averaged over the entire run.
- The supply ratio *(MW/MW)*: the ratio of available supply over peak demand.
- The cost of the capacity mechanism (€/MWh): the cost incurred by the consumers for contracting the mandated capacity credits in the capacity market or for contracting generating units into the strategic reserve.
- The cost to consumers (€/MWh): the sum of the electricity price, the cost of the capacity market and the cost of renewable policy (if applicable) per unit of electricity consumed, averaged over the entire run.

The shortage hours and the supply margin provide insight into the impact of capacity mechanisms on the security of supply. The average electricity price, the cost of the capacity mechanism and the cost to consumers provide insight into the impact of capacity mechanisms on the overall economic efficiency.

2.5 Model limitations

In this model, the generators are assumed to bid at marginal costs at all times. The power generating companies do not exercise market power or any other kind of strategic behavior in the electricity market or while participating in the capacity mechanisms. Thus the risk that generation companies might withhold capacity when the supply ratio is tight, in order to activate the reserve and thereby increase the price, is not taken into account. The effect of strategic bidding on the capacity market is also not considered. Innovation is limited to the the gradual improvement of generation technologies in terms of cost and performance, thus no entirely new technology becomes available within a model run.

Demand response and storage have also been left out of the scope of this research. The capacity mechanism design was not adjusted to cross-border trade: neither cross-border trade of capacity rights or any kind of export restriction was included. Finally, as EMLab-Generation was developed to study the long-term development of electricity markets under different policy conditions, short-term operational constraints and unplanned shutdowns of power plants were not modeled. These limitations, along with the segmented nature of the load-duration curve, cause the short-term dynamics to be less precise.

3. Strategic Reserve

This chapter is based on Bhagwat et al. (2016d) with minor modifications.

3.1 Introduction

In this chapter the effectiveness of a strategic reserve is investigated with respect to incentivizing adequate generation investment in an isolated electricity system without and with a strong growth in the portfolio share of intermittent or variable renewable energy sources (RES).

A strategic reserve (Cramton et al., 2013; Rodilla and Batlle, 2013) typically consists of generators with high operating costs and/or demand-side resources that are contracted by the transmission system operator (TSO) and are dispatched when the market does not provide sufficient generation capacity. Conceptually, a strategic reserve may resemble operating reserves pricing (Stoft, 2002), depending on whether the decision to dispatch the reserve units on short notice is made as a function of the electricity price or some other variable. In Sweden, a strategic reserve was implemented to prevent old units from being decommissioned, despite their limited economic prospects. In southern Germany, a strategic reserve is currently used to allow the transmission system operator to purchase electricity from units that are more expensive than the market price, but that are locally needed due to network constraints. In this case, the reserve is used for congestion management.

The creation of a strategic reserve itself might not change the volume of available generation capacity, as it simply transfers the control of some power stations to the transmission system operator (TSO). The exception is if, by doing so, it prevents plant from being decommissioned. In case there is not enough available generation capacity, the TSO dispatches the strategic reserve at a price above the variable costs of the generation units. This will cause the average electricity price to increase and thus stimulate investment in generation capacity. The market design challenge, therefore, is to ensure that the dispatch price of the reserve provides an adequate investment incentive.

The existing agent-based model of electricity markets called EMLab-Generation (De Vries et al., 2013; Richstein et al., 2015a, 2015b, 2014a) described in Chapter 2 is expanded by adding a strategic reserve module. In the next section, the fundamentals of designing and operating a strategic reserve are described. In Section 3, the implementation of a strategic reserve in this model and the calculation of the strategic reserve parameters are explained. Section 4 describes the scenarios used for the model runs. In Section 5, the results of the analysis of the effectiveness of a strategic reserve without and with a large share of renewable energy sources in the generation portfolio are presented. A Monte Carlo-style analysis with uncertain demand growth rate and fuel-price developments is used. The indicators used in this analysis are described in detail in Section 5.1. The conclusions are summarized in Section 6.

3.2 Designing and operating a strategic reserve

3.2.1 Overview

A strategic reserve is defined as a set of power plants and/or interruptible demand contracts that are controlled by the transmission system operator, to be deployed during shortages (De Vries, 2004; De Vries and Heijnen, 2006; Rodilla and Batlle, 2013). A strategic reserve that is dispatched when the market price exceeds a certain level is analyzed. Alternative dispatch criteria, such as those based on the reserve margin (defined as the available generation capacity over the peak demand) is not considered. In the basic strategic-reserve design, the system operator contracts electricity generation units with high operating costs (ideally, the last units in the merit order) and offers their electricity to the market at a price (PSR), which is well above their variable cost (see Figure 3.1). The pays the owners of these power plants their annual operations and maintenance costs. If the reserve capacity is dispatched, the operator pays the owners of these power plants their marginal cost of generation. Thus the operator pays all the reserve costs and keeps (most of) the profit when the reserve is dispatched. From the perspective of the operator, these profits should cover the fixed costs, but the operator takes the financial risk of keeping the reserve units available. In case the operator is unable to recover all its cost of contracting the reserve, the remaining costs are socialized (or spread across usage) as part of the network or system tariffs.

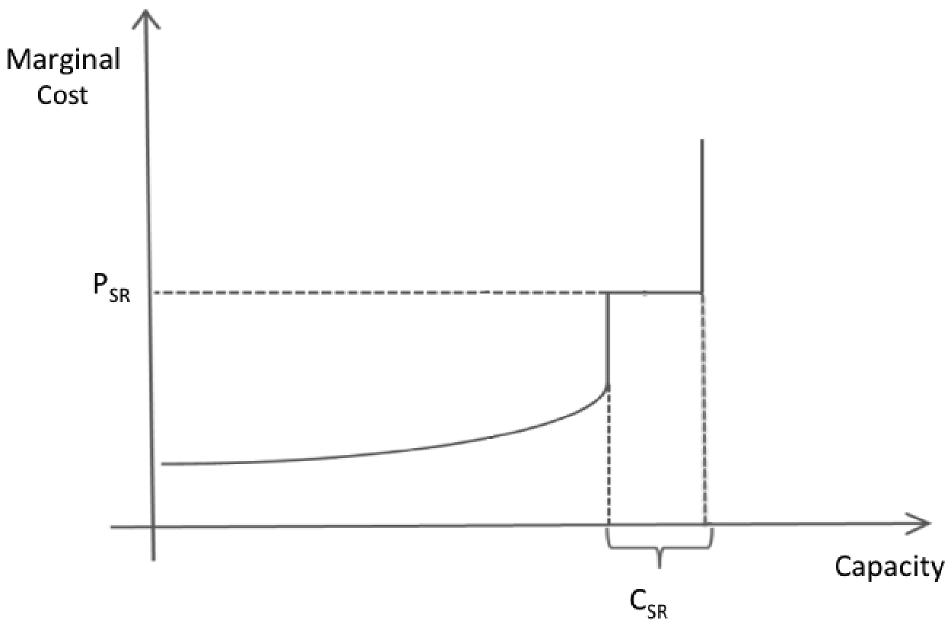

Figure 3.1: Example of impact of strategic reserve on the supply curve (De Vries, 2004)

3.2.2 Reserve design

A strategic reserve with a price-based dispatch criterion, as analyzed here, withdraws a certain volume of generation capacity from the market and makes it available at a price that is (substantially) higher than its variable cost. This should stimulate investment in generation capacity as explained by Stoft (2002). The level of the reserve dispatch price (P_{SR}) is a key factor, as it effectively caps the market price (Stoft, 2002; De Vries and Heijnen, 2008). It therefore determines the strength of investment incentive, and, as a consequence, the total equilibrium volume of generation capacity and hence the level of generation adequacy. In principle, the reserve price P_{SR} should be determined such that the revenues earned by the power producers in the presence of the strategic reserve are equivalent to the revenues that they would have earned in an energy only market. In a perfect market, if the supply ratio[4] was optimal without the reserve, the reserve should lead to the same supply ratio. In case of market imperfections that cause insufficient investment, the reserve could provide compensation by raising generation companies' average revenues. The determination of an optimal supply ratio is beyond this research's scope. In theory, it should follow from the minimization of social costs, but in practice it is often determined by the regulator. In this research, the focus is on the effectiveness of a strategic reserve in providing reliability without and with a large share of renewable energy sources in the generation mix. A second criterion is the impact of the strategic reserve on economic efficiency.

The only time when the reserve price does not function as a maximum price is the rare occasion when the reserve is exhausted. Then the price may increase to the value of lost load if there are no more demand-side resources available. If the reserve functions well, it has attracted sufficient investment in generation capacity and is exhausted only under rare circumstances. As a result, generators lose some peak revenues. With a well-designed reserve, this loss is offset by the fact that the reserve increases the market price up to P_{SR} during other hours, namely when there is no absolute shortage but the reserve is needed to meet demand. The challenge is to design the reserve so it balances these two effects. Consequently, in a market with a strategic reserve, price spikes up to P_{SR} occur more frequently than scarcity prices would occur in a system without a reserve, but these price spikes are lower. The lower but more frequent price spikes should make electricity prices more predictable and investment consequently less risky, according to Stoft (2002). This change in the shape of the price-duration curve is described in Section 3.2.

3.2.3 The dismantling paradox

During the development of this model, an interesting long-term effect of a strategic reserve was observed, which is labeled as "the dismantling paradox". In the long run, a strategic reserve may distort the merit order by supporting power generation units that should be dismantled and which may also be the most polluting. A strategic reserve may be intended to prolong the service life of old power plants, but over time this may cause a dilemma when the oldest plant in the system is no longer necessary or should be replaced for economic reasons. Investment in new plants, new interruptible demand contracts or declining demand, in combination with the aging of the plants in the reserve, may create a situation in which the marginal plant no longer is economic, even as part of the reserve. However, if the system operator ceases to contract it, its owner could offer it to the market at its marginal cost, which is below the reserve price. This plant would then be the last to be dispatched before the

[4] Supply ratio is defined as the ratio of available supply at peak over peak demand

reserve, running at least as many hours as the reserve, while being less efficient than the plants in the reserve. As this would artificially increase its operating hours, relative to its position at the end of the merit order, it could make the plant profitable again, causing it to continue to be profitable despite its position at the end of the merit order. The extent to which this occurs depends on the shapes of the supply and demand functions. This behavior was encountered in the model runs.

A similar risk exists for demand resources with relatively high activation costs (resources that require a relatively high remuneration per MWh of load reduction). If cheaper demand resources become available, the system operator would prefer them. However, if the operator does not contract the more expensive demand resources, the latter may be offered to the market and dispatched before the strategic reserve, out of merit. A key difference with generators with high variable costs is that demand resources do not age and do not need to be dismantled. The advent of cheaper demand resources may simply mean that size of the strategic reserve can be reduced.

3.3 Model description

3.3.1 The strategic-reserve algorithm

The strategic reserve is modeled as an extension of EMLab-Generation. The algorithms that determine the behavior of the strategic-reserve operator in this model are described here. The operator contracts the most expensive power plants, based on their variable costs, until the reserve has the required volume. The operator selects these plants because they are the least likely to run, so the opportunity cost of withdrawing them from the market is the smallest. This means that, if a tendering process were organized, they would have made the lowest bids. The strategic reserve only contracts complete power plants, thus the full capacity of the last required power plant is contracted.

The owners of the contracted power plants are paid the annual fixed operating costs of the plants and the plants are offered to the electricity spot market at the strategic reserve dispatch price (P_{SR}). In the event that this capacity is sold in the market and dispatched, the strategic reserve operator keeps the revenue earned by the generating units in the reserve (R_{GR}) above their variable costs of generation (VC). This can be defined as the revenue of the strategic reserve operator (R_{SR}) (see Equation (1)).

$$R_{SR} = R_{GR} - VC \tag{1}$$

If all non-contracted generators are running and the reserve is also not large enough to meet demand, there is a physical shortage of electricity. In this case, the market price is set equal to the value of lost load (VOLL) in the model. It is assumed that the system operator passes on the reserve costs to the consumers via the network tariffs. The process of contracting power plants for the strategic reserve is presented in a flowchart below (Figure 3.2).

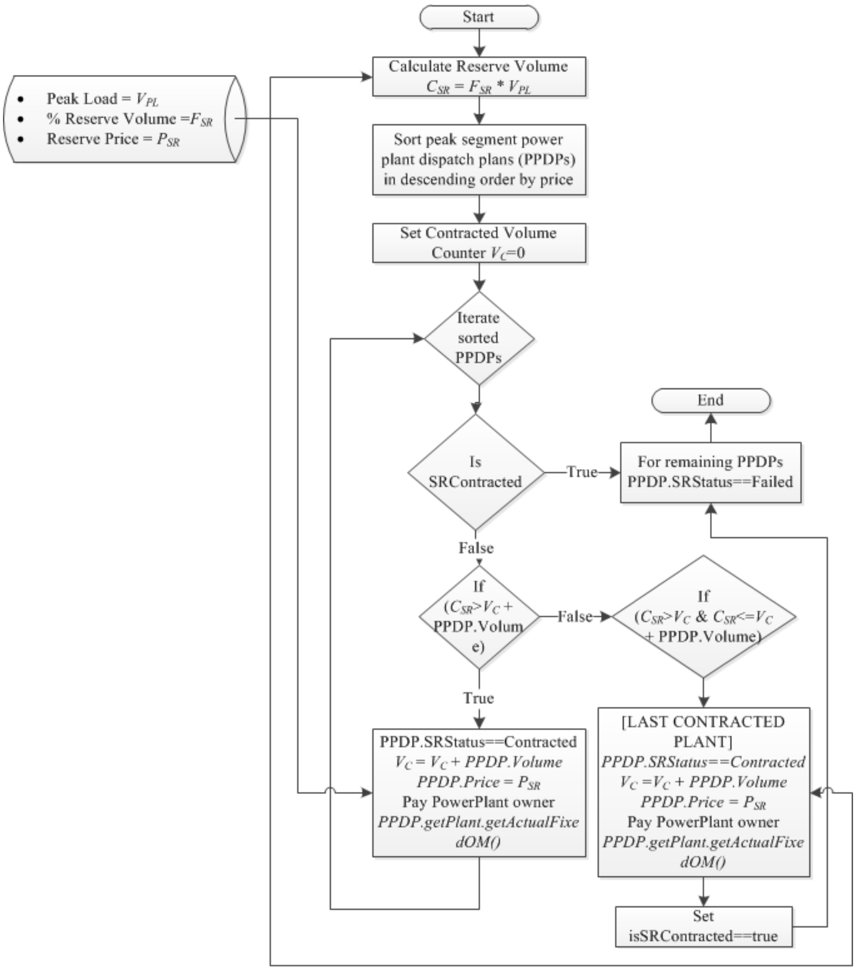

Figure 3.2: Stylized flowchart of the algorithm for contracting power plants for the strategic reserve.

3.3.2 Determining the strategic-reserve parameters

The description of how the key parameters of the reserve are chosen is presented. The regulator needs to choose either the reserve size or the dispatch price P_{SR} and calculate the other variable so that the average revenues of the generators are just sufficient to remunerate their investments. The regulator could also implement a step-wise dispatch price function by making capacity from the reserve available at different price levels, but for simplicity a single dispatch price for the entire reserve is considered. In the model, fixing the reserve volume was most practical. The system operator in the model chooses the size of the strategic reserve as a fraction F_{SR} of expected peak demand to be contracted.

In every time step, the total capacity contracted into the strategic reserve (C_{SR}) is calculated from the fraction of the reserve volume (F_{SR}) over peak load, multiplied by the peak load (V_{PL}) (see Equation (2)).

$$C_{SR} = F_{SR} * V_{PL} \tag{2}$$

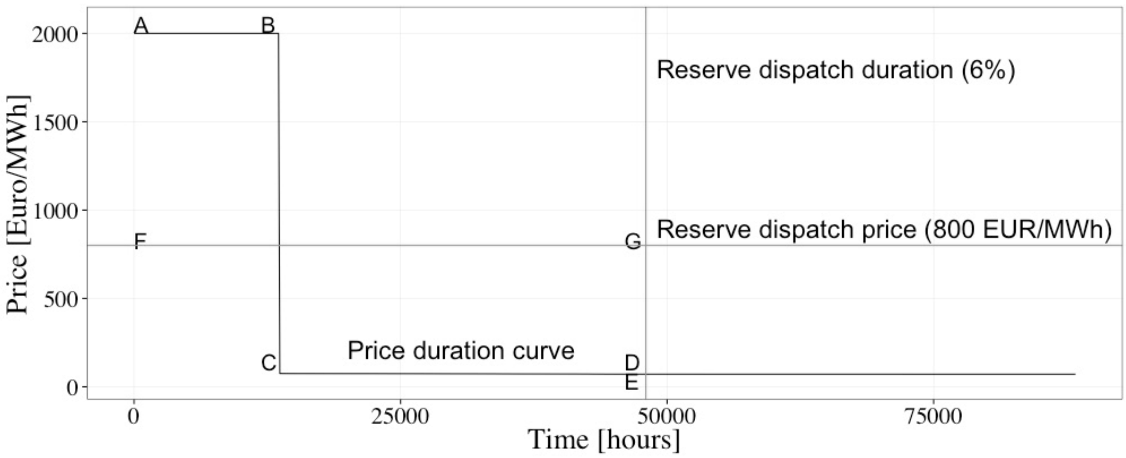

Figure 3.3: Modification to the peak of the price-duration curve due to a strategic reserve.

In calculating the reserve price from the reserve volume, the principle is applied that (in a perfect market) the reserve should not change the average electricity price. Thus, the total revenues earned by the generators during the hours when the reserve sets the price in a market with a strategic reserve should be equal to the revenues earned by the power producers during the same hours in an energy-only market. In other words, the revenue loss that generators experience due to fewer hours of scarcity prices should be perfectly compensated by an increase in revenues during hours when the reserve has the effect of raising the electricity price from the marginal cost of generation to the reserve price. This is illustrated in Figure 3 with a simplified price-duration curve where the area under the curve represents the revenues earned by the power producers. The reserve price (indicated by line FG) must be adjusted such that the area under polygon ABCDE must be made equal to area under polygon FGDE for a fixed reserve volume.

In order to determine the dimensions of the strategic reserve, a baseline scenario with fixed fuel prices and no demand growth is run 120 times over a time horizon of 40 year. A price-duration curve is created from the electricity prices in these runs. Next, the reserve volume is set as 6% of the peak demand, as at this volume of capacity the reserve must be active for 10 hours annually on average. Since electricity prices from all the runs are considered as separate data points, this reserve volume would lead to 48,000 hours with reserve prices (P_{SR}) over the entire simulation (of 10 hours * 40 years * 120 runs). As it is assumed that the presence of a strategic reserve does not affect electricity prices during the hours that the reserve is not activated, this analysis is restricted to the segments of the load-duration curve during which the reserve would be activated, if present.

In the next step, the total revenue generated during the 48,000 peak hours of the combined load-duration curve is calculated. The model has a segmented load-duration curve, so the total revenue earned by the competitive generators is calculated as the summation of the revenue per segment of the load-duration curve for all the segments that together make up the 48,000 peak hours. The revenues per segment are equal to the product of the price, the number of hours in the segment and the volume of generation in the segment. Total generator revenues in an energy-only market R_{eom} are given by:

$$R_{eom} = \sum_{i=1}^{n} P_i * h_i * g_i \quad (3)$$

Here, n is the number of segments in the load-duration curve during which the reserve would be activated, P_i is the price in segment i, h_i is the number of hours in segment i and g_i is the total generation in segment i.

If a strategic reserve is implemented, the price during these segments is equal to the reserve dispatch price P_{SR}. Then, the generation companies' revenues R_{SR} are determined by the reserve dispatch price instead of the market price:

$$R_{SR} = \sum_{i=1}^{n} P_{SR} * h_i * g_i \quad (4)$$

If the strategic reserve is not to change average revenues, Equation (3) must equal (4). This way, the strategic reserve price P_{SR} is calculated.

3.3.3 Strategic reserve in a static thermal-only scenario

The process described in Section 3.2 is utilized to determine the strategic-reserve parameters in a scenario with static fuel prices, zero demand growth, and thermal-only generation capacity: the *Deterministic Baseline Scenario*. The purpose is to determine an optimal strategic reserve for the starting situation of the model. The main source of uncertainty in this scenario arises from the power producer's investment decisions, as described in Chapter 2. The reserve volume is set at 6% (V_{SR}); the corresponding dispatch price (P_{SR}) was calculated to be 800 €/MWh in the previous section. When the model is run again, under the same Deterministic Baseline Scenario, with the strategic reserve, it is found that the reserve is dispatched 6.9 hours annually on average. The supply ratio increases by 5.3% (see Figure 3.4) and the number of shortage hours is reduced by 95% to 0.13 hours per year (see Figure 3.5). The strategic reserve operator does not recuperate all the cost of contracting the reserve, but this cost amounting to 0.23 €/MWh is just 0.6% of the total cost to consumer which is 39.33 €/MWh. As average prices are comparable to the situation without a strategic reserve, the average cost to consumers remains comparable to the baseline scenario. These results validate the method used for sizing the reserve.

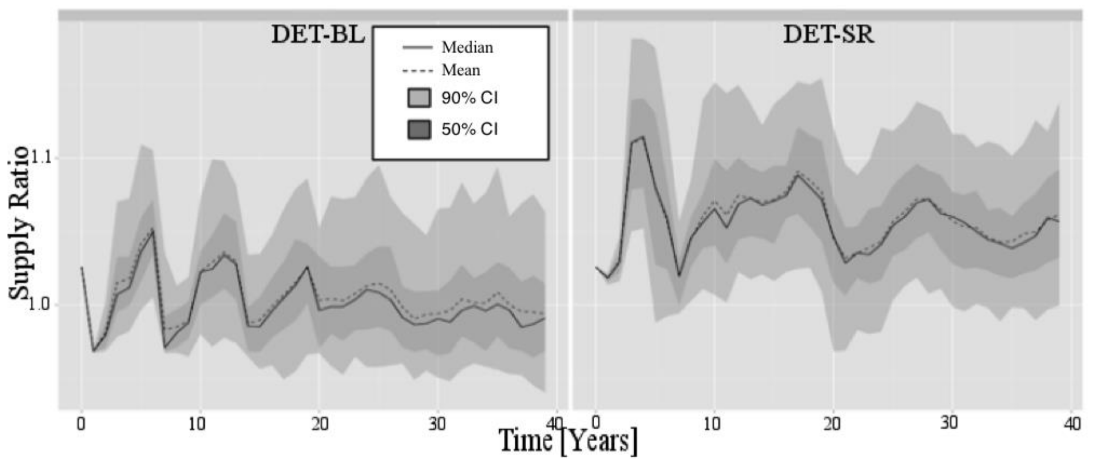

Figure 3.4: The supply ratio without (left) and with (right) a strategic reserve in a scenario without demand growth

Another observation is that in the presence of a strategic reserve there is a more gradual rise and fall in the supply ratio in this static scenario, as seen in Figure 3.4. Comparing this result with the electricity prices shown in Figure 3.6 reveals that when the supply ratio starts to decrease, the average electricity price rises as the reserve is activated more frequently. Although in some scenarios there are strong swings in the electricity price, the median (see Figure 3.7) and mean (see Table 3.4) of the price are lower with a strategic reserve in the baseline scenario throughout the time horizon under consideration.

At the beginning of the run with a strategic reserve, high electricity prices are observed. The reason is that at the start of the run, the supply ratio is lower than the equilibrium level for the market with a strategic reserve, so until new capacity gets built, the reserve is activated more frequently than the long-term average. The sharp decline in average price during the succeeding period also indicates that the strategic reserve provides a strong incentive for investment in new generation capacity (Figure 3.6). In fact, the model indicates an investment overshoot and subsequent dip in capacity; this points to the need to phase in a reserve of this size in a system with a tight supply ratio. The price-duration curve in which the price data is presented in a descending order of magnitude is illustrated in Figure 3.7. The average number of hours for every price level each year is calculated based on the electricity price data obtained from the 120 Monte-Carlo runs for the given scenario. A reduction in the occurrence of sharp price peaks caused by scarcity is observed, as expected from theory.

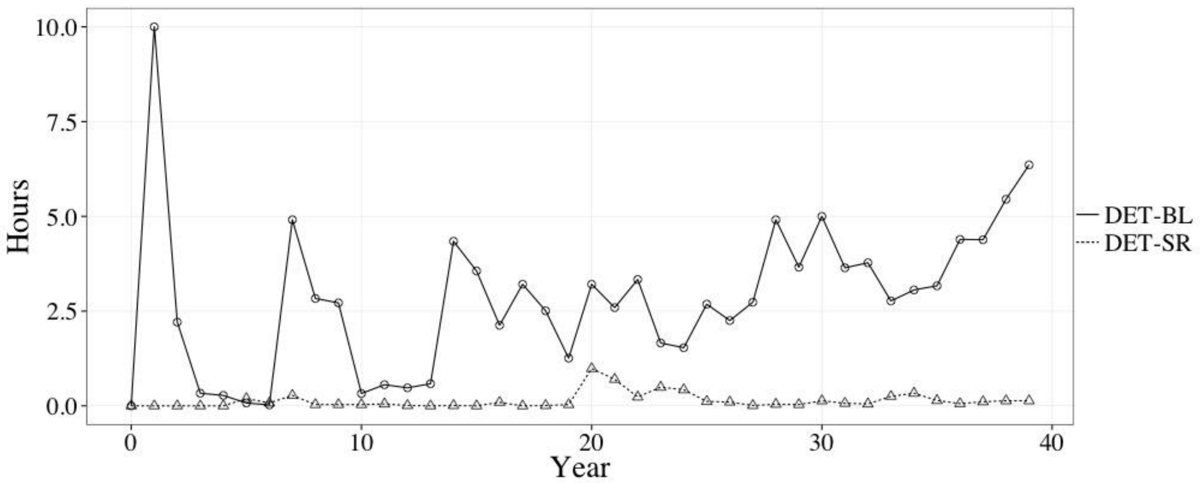

Figure 3.5: Comparison of change in average shortage hours in scenario without demand growth (DET-BL) and with (DET-SR) a strategic reserve

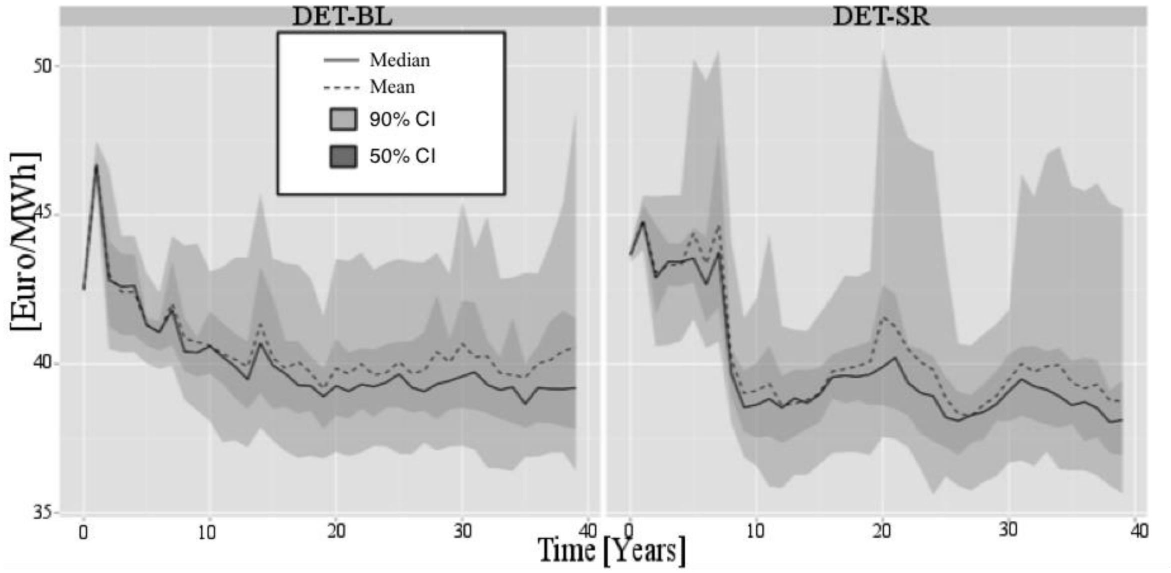

Figure 3.6: Electricity prices in a scenario without demand growth, without (left) and with (right) a strategic reserve

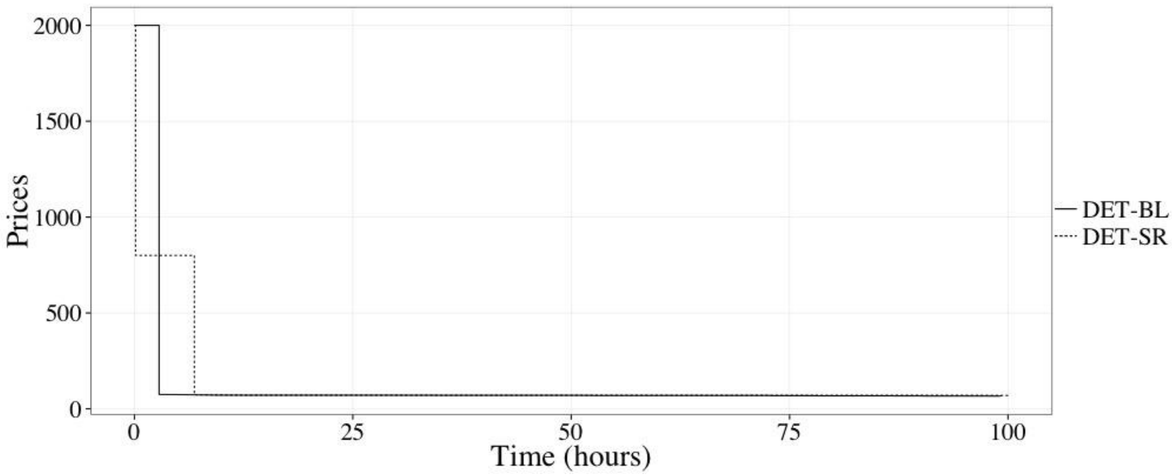

Figure 3.7: Peak section of the price-duration curve in a scenario without demand growth, without (DET-BL) and with a strategic reserve (DET-SR)

3.4 Scenarios

The effectiveness of a strategic reserve in an environment with uncertain demand growth and fuel prices is tested first. These scenarios only include thermal power plants. Subsequently, a growing share of variable renewable energy is added in order to answer the main research question, namely how this relates to the effectiveness of the reserve.

In all scenarios, a market with four identical power producers is considered. The initial supply mix consists of four power-generating technologies (Coal, CCGT, OCGT, and Nuclear). The shares of the different technologies in the supply mix are based on the power-generation capacity portfolio of Germany in 2010 (based on Eurelectric (2012) data; see Appendix C). The load-duration function in this paper is based on the 2010 ENTSO-E data for Germany. The coal and gas prices trends are based on fossil-fuel scenarios published by

Department of Energy and Climate Change (2012). The biomass cost trends are based on Faaij (2006) and those for lignite are based on Konstantin (2009).

Each scenario was run 120 times according to the Monte Carlo method with the same starting conditions but with different fuel-price and demand-growth assumptions. All scenarios consist of 40 time steps each of which represents one year. A triangular probability distribution was used to create variations in electricity demand growth and fuel prices around an average growth rate (Appendix A and F). The TM scenario serves as a reference case for understanding the effects of a strategic reserve under dynamic conditions. This scenario is run for a baseline case without a strategic reserve (indicated as TM-BL) and for a case with a strategic reserve (indicated as TM-SR).

In the second scenario ('RES'), the share of (variable) renewable energy in the supply mix grows substantially (see Table 3.1). This is the key scenario for the analysis, which is used for analyzing the effectiveness of a strategic reserve in the presence of a growing share of renewable energy in the total generation portfolio of the system. The renewable energy trends are based on the German renewable energy action plan (NREAP, 2010) until 2020 and extrapolated further. Aside from the share of renewable energy, the same scenario as in the thermal-only case (TM) is used. Again, a baseline run for an energy-only market (RES-BL) and a run with the same strategic reserve as before (RES-SR) is made.

Table 3.1: Development of the supply-mix in scenario with growing RES

		Scenario V	Scenario VI
Technology	**Initial Mix**	**Final Mix**	**Final Mix**
Coal	50.0%	11.0%	10.7%
CCGT	19.0%	8.2%	8.0%
OCGT	13.0%	1.5%	3.4%
Nuclear	18.0%	3.0%	3.0%
IGCC	-	1.5%	1.6%
Wind Offshore	-	10.7%	10.5%
PV	-	51.1%	50.2%
Wind	-	11.3%	11.1%
Biomass	-	1.6%	1.6%
CCGTCCS	-	-	-
CoalCCS	-	-	-
Lignite	-	-	-
Biogas	-	-	-
IGCCCCS	-	-	-
Total	100.0%	100.0%	100.0%

Estimating the value of lost load is difficult (Cramton et al., 2013; Stoft, 2002). The estimates of the value of lost load in literature (Anderson and Taylor, 1986; Baarsma and Hop, 2009; Leahy and Tol, 2011; Linares and Rey, 2013; Pachauri et al., 2011; Wilks and Bloemhof, 2005) vary widely depending on the location and nature of the load. In this modeling study, the value of lost load (VOLL) was chosen at the relatively low level of 2000 €/MWh. This level is chosen in order to take into account demand flexibility that might occur during periods of high prices.

Table 3.2: Scenario parameters

Scenario	RES	Strategic Reserve
TM-BL	-	-
TM-SR	-	×
RES-BL	×	-
RES-SR	×	×

Table 3.3: Description of scenario abbreviations

SR NO	Code	Description
1	TM	Thermal Mix only
2	RES	Renewable energy policy enabled
3	BL	Baseline energy-only market
4	SR	Strategic reserve implemented
5	DET	Determination of reserve scenario

3.5 Results and analysis

3.5.1 Introduction

In this section, the results of running the above-mentioned scenarios in this model are presented. The following indicators are applied to evaluate the effectiveness of the strategic reserve:

- Average electricity price (€/MWh): the average electricity price over the entire run.
- Strategic-reserve dispatch duration (hour/year): the average number of hours that the reserve is dispatched per year.
- Shortage hours (hour/year): the average number of hours per year with scarcity prices, averaged over the entire run.
- Cost to consumers (€/MWh): the sum of the electricity price, the net cost of the reserve, and cost of renewable policy (if applicable) per unit of electricity consumed.[5]
- The cost of the strategic reserve (€/MWh): the net cost of maintaining the strategic reserve to the system operator, which is equal to the fixed and operating costs of the reserve minus the revenues from operating it. (A negative value would indicate a profit to the operator.)
- Supply ratio: the ratio of available supply at peak over peak demand.

[5] Note that this includes the cost of outages, because in the model the electricity price rises to the VOLL during shortages.

- Outage cost per year (€/y): the product of the value of lost load (2000 €/MWh) and the annual load not served (MWh). This value indicates the cost to consumers due to shortages of supply.

An overview of the results of the simulation is presented graphically in Figure 3.8. Table 3.4 contains the average values for the same variables over all runs. In the remainder of this section, the results are discussed per scenario and graphically present supply ratios, average electricity prices, and shortage hours over time. For the supply ratios and electricity prices over time, the median trend and the 50% and 90% confidence intervals (CI) are shown. The average values presented in the results are calculated as annual values based on values from the 120 simulation runs over the 40-year time horizon.

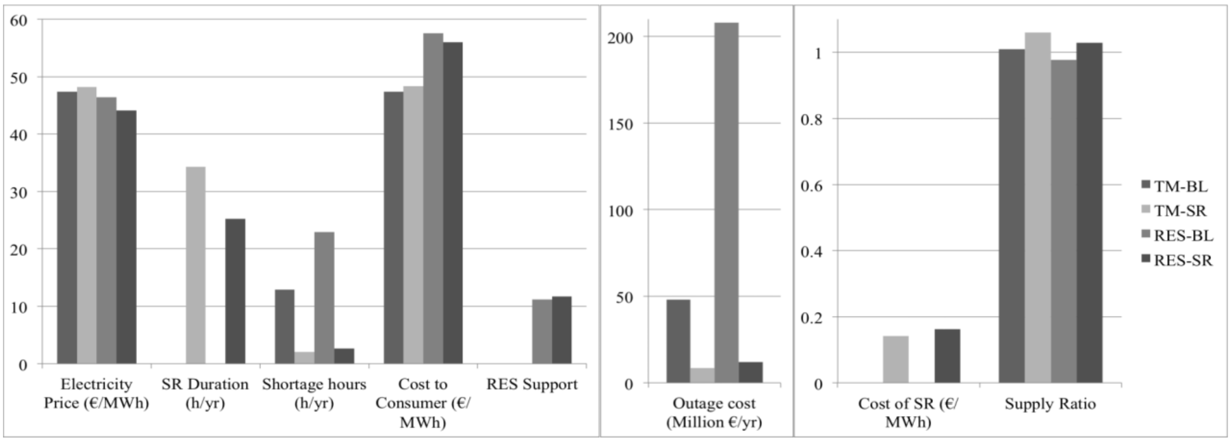

Figure 3.8: Comparison of indicators for the TM and RES scenarios (SR Duration stands for Strategic reserve dispatch duration).

Table 3.4: Annual average values of key indicators for the deterministic scenarios

Scenario Name	Cost to Consumer (€/MWh)	Electricity Price (€/MWh)	Cost of SR (€/MWh)	RES Support (€/MWh)	Shortage hours (h/yr)	SR Duration (h/yr)	Outage cost (Million €/yr)	Supply Ratio
DET-BL	39.36	39.36	N.A.	N.A.	2.82	N.A.	4	1.01
DET-SR	39.33	39.09	0.23	N.A.	0.13	6.9	0.17	1.06
TM-BL	47.39	47.39	N.A.	N.A.	12.87	N.A.	48	1.01
TM-SR	48.34	48.20	0.14	N.A.	2.07	34.3	8.5	1.06
RES-BL	57.54	46.38	N.A.	11.168	22.96	N.A.	208	0.98
RES-SR	55.97	44.10	0.16	11.711	2.67	25.3	12.8	1.03

3.5.2 Thermal-only generation portfolio with demand growth

It is tested here whether the strategic reserve that is designed in Section 3.2, is effective in a scenario with stochastically varying fuel prices and growing demand (TM-SR). The results are compared with those of the same scenario without a strategic reserve (TM-BL).

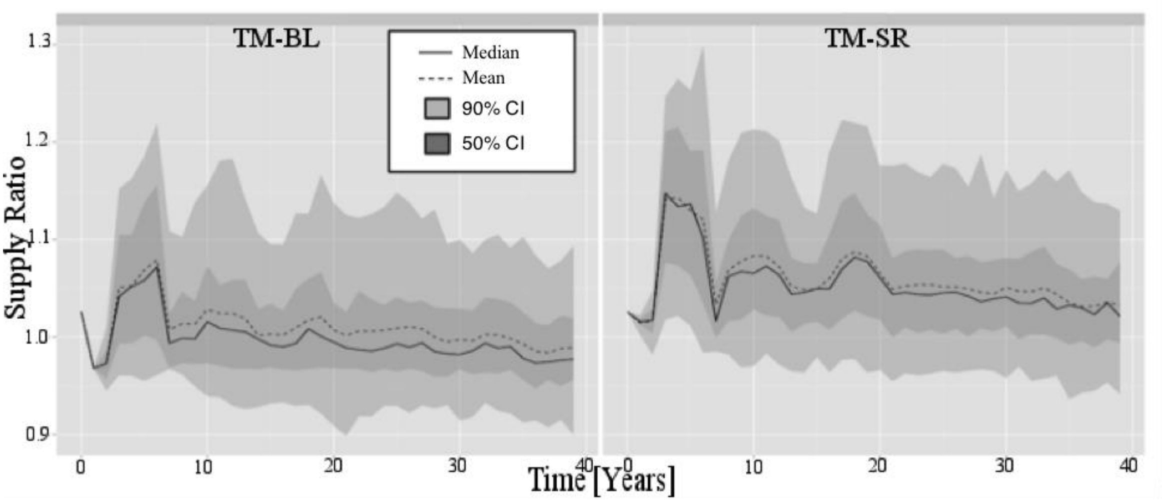

Figure 3.9: Supply ratio in a scenario with stochastically varying fuel prices and rising demand, without (left) and with a strategic reserve (right)

The presence of a strategic reserve leads to an increase of 5% in the supply ratio, reducing the average number of shortage hours per year by 84%, from 12.9 h/y to 2.1 h/y (see Figure 3.8 and Table 3.4). In Figure 3.9, it can be observed that a strategic reserve indeed improves the supply ratio. An overshoot in the supply ratio is observed at the beginning of the simulation run in both the TM-BL and TM-SR scenarios (see Figure 3.9). This is because the agents in the model cannot develop forecasts due to insufficient information for previous years. This initial cycle should be considered a model artifact.

The strategic reserve is dispatched 34.3 hours per year on average, leading to a 1.7% rise in the electricity prices and a 2% increase in the cost to consumers. The difference is caused by the cost of the reserve (see also Table 3.4). It can be observed from Figure 3.10 that the presence of a strategic reserve leads to a consistent reduction of shortages.

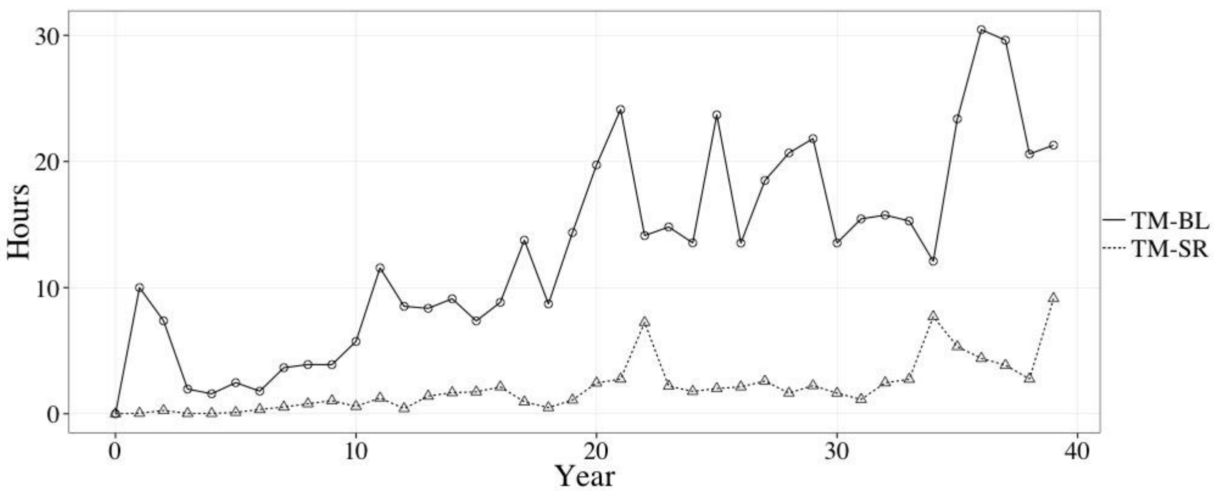

Figure 3.10: The average number of shortage hours in a scenario with stochastic fuel prices and a rising demand, without (BL) and with a strategic reserve (SR)

Even if the average supply ratio does not change, price cycles increase the net income of the strategic reserve operator because the reserve is used more frequently. This reduces the cost of maintaining the strategic reserve as compared to the design case (DET-SR) from 0.23 €/MWh to 0.14 €/MWh. In some scenarios, there is a possibility of reserve imbalance and development of investment cycles. As illustrated by the price-duration curve in Figure 3.11, the presence of the reserve leads to a reduction in occurrence of sharp price peaks caused by scarcity as expected from theory. This can be further confirmed from the mean and median values shown in Figure 3.12.

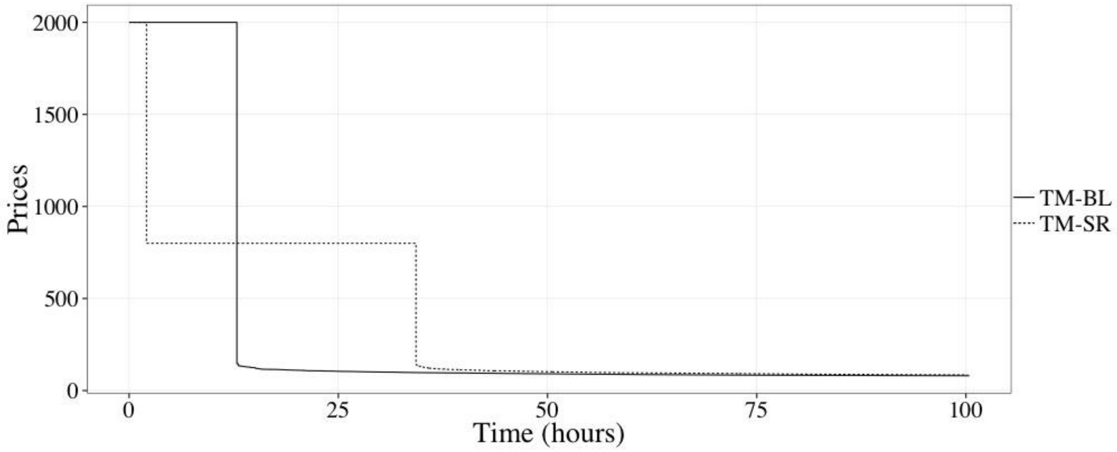

Figure 3.11: Peak section of the price-duration curve in scenarios with stochastically varying fuel prices and rising demand, without (BL) and with a strategic reserve (SR)

In a dynamic setting (TM), the strategic reserve is less effective in improving the supply ratio and reducing shortage hours than in the static design case (DET). The reason is that uncertainty about future demand always causes some investment overshooting and undershooting. However, the strategic reserve still reduces shortage hours to 2.07 hours per year, which corresponds to a decrease in outage costs from €48 million to €8.5 million per year. However, now the net cost to consumers is 48.34 €/MWh, which is 2% higher than in the baseline scenario (TM-BL). This rise in the cost to consumers is equivalent to €564 million annually. Therefore, in this case, the presence of a strategic reserve reduces net consumer benefit. The consumer benefit from a reduction in shortages depends on the value of loss load for individual consumers. A relatively low value of lost load (2000 €/MWh) is used; the consumer benefit from reduced outage costs would be significantly higher with the use of a higher VOLL for this calculation.

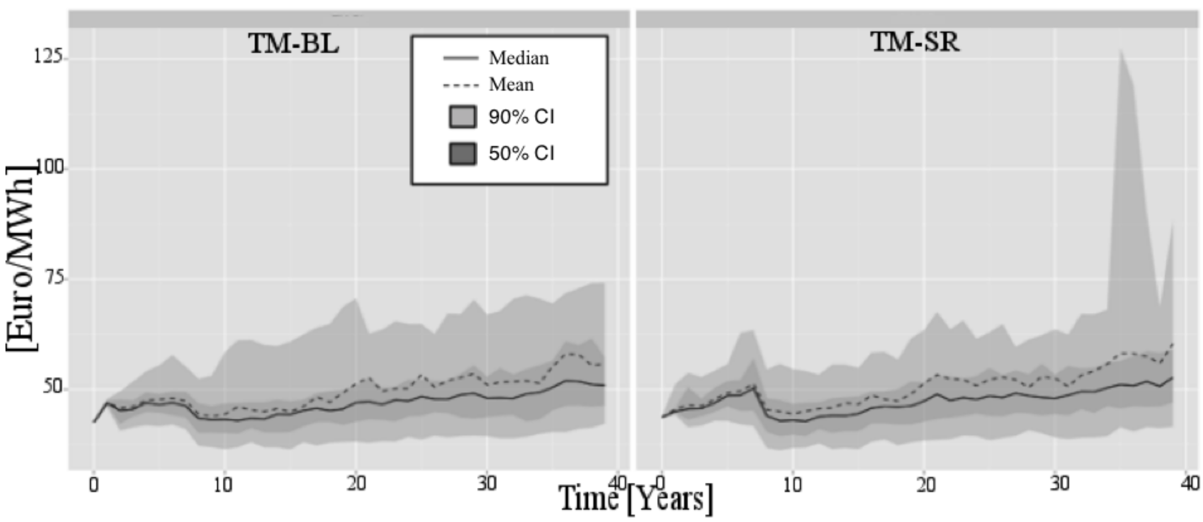

Figure 3.12: Electricity prices in a scenario with stochastic fuel prices and rising demand, without (left) and with a strategic reserve (right)

3.5.3 Generation portfolio with RES

The expansion of renewable energy increases the availability of inexpensive but intermittent electricity, which reduces the window of opportunity for thermal power generators to recover their investment; scenarios RES-BL and RES-SR represent this case. In the latter scenario, the size of the strategic reserve is the same as in the thermal-only scenario of the previous section. This simulates a shift from a completely thermal energy mix to a renewable energy mix without a change in the design of the strategic reserve. The presence of a high share of variable renewable energy depresses the investment incentive, as a result of which the number of shortage hours nearly double (from an average 12.8 h/y in TM-BL to 23.0 h/y in RES-BL). Introducing a strategic reserve reduces the number of shortage hours to 2.7 h/y on average, which corresponds to a reduction in outage costs from €208 million to €12 million annually (see Figure 3.13).

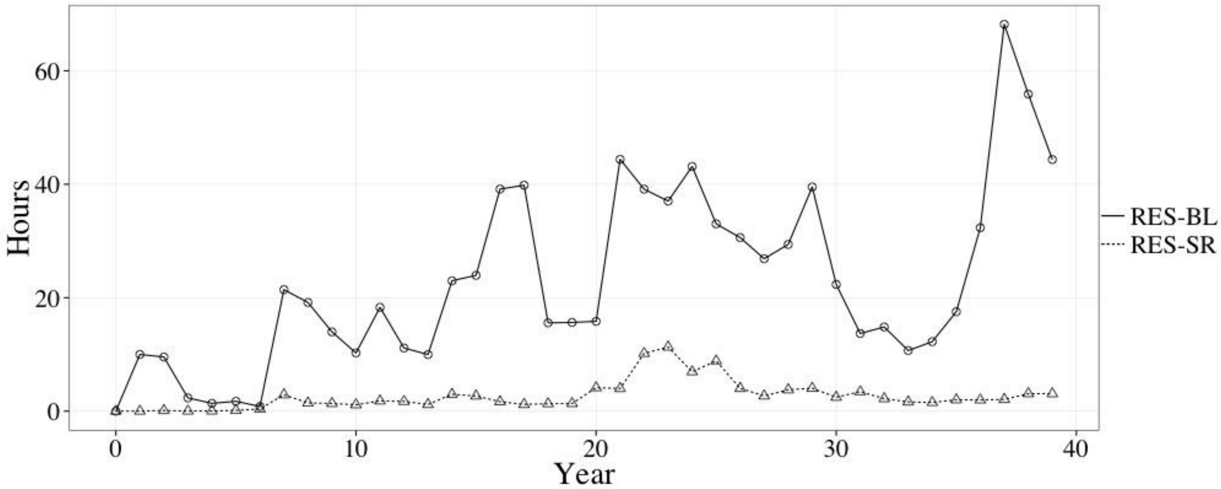

Figure 3.13: The average number of shortage hours per year in a dynamic scenario with increasing RES, without (BL) and with a strategic reserve (SR)

On average, the strategic reserve was dispatched for 25.3 hours per year. Again, it improved the supply ratio by about 5% (see Figure 3.13). However, as can be observed in Figure 3.14, although the strategic reserve's effectiveness over the first 20 years is satisfactory, there is a gradual decline in the supply ratio over the time horizon of the simulation. The effectiveness of a strategic reserve in providing an adequate investment incentive declines with the increasingly steep residual load-duration curve that is the consequence of a growing share of renewable energy in the portfolio. Therefore, in the longer term, it may be necessary to establish a more robust reserve by sizing the reserve with a higher price or volume in the first place or by adjusting the reserve periodically. In the next section, the possible resizing options available to the system operator are discussed.

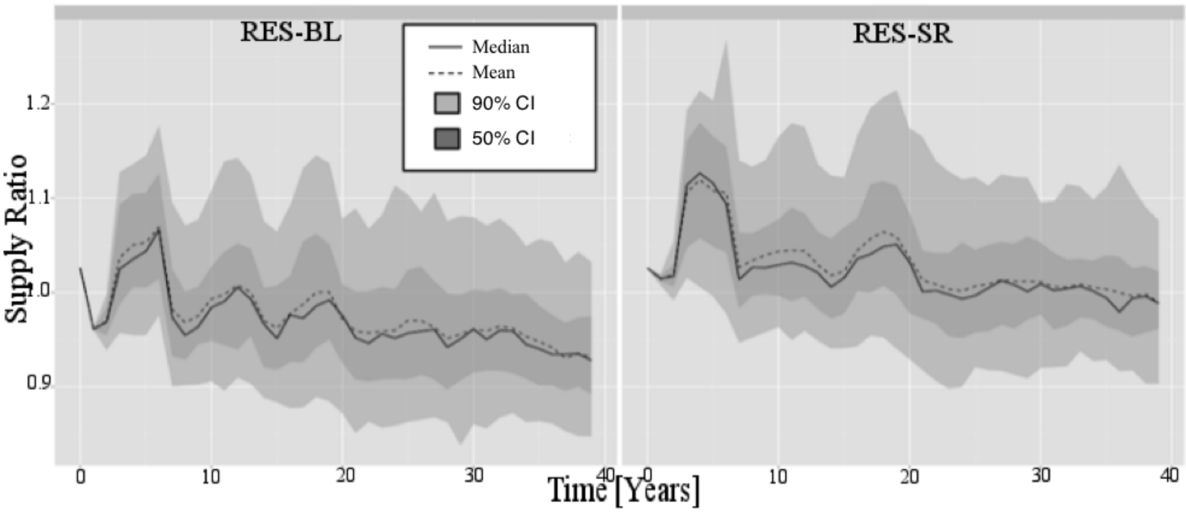

Figure 3.14: Supply ratio in a dynamic scenario having increasing RES without (left) and with a strategic reserve (right)

Contrary to the thermal-only case, the presence of the reserve led to an average reduction of electricity prices of 5%. Two main factors contribute to this price reduction. First is the steep reduction in the period with scarcity prices (that is, shortage hours), as explained above. Second is the higher availability of RES capacity in off-peak segments combined with the larger generation capacity available at the peak. Thus, for the same supply ratio, more capacity would be available (at a cheaper price) in the off-peak segments of the load-duration curve in a RES scenario as compared to the thermal-only scenario. This not only reduces the number of hours for which the reserve is active but it also pushes out the more expensive thermal power plants from the merit order.

As observed in Figure 3.15, the presence of a strategic reserve is associated with a strong decline in the occurrence of extreme price spikes, leading to more stable electricity prices, as was also observed in the thermal-only scenario (see Figure 3.16). The lower prices increase the need for renewable energy subsidies, but a net reduction in the cost to electricity consumers remains. This 2.7% net reduction in consumer costs is equivalent to €980 million per year. The reserve is used fewer hours than in the thermal-only scenario (25 instead of 34 hours per year on average) because some of the demand peaks are met by variable renewable energy.

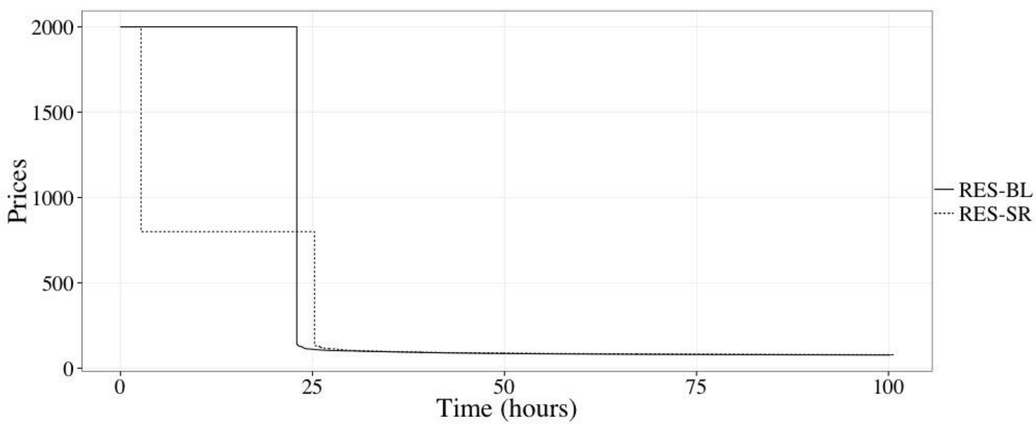

Figure 3.15: Peak section of the price-duration curve in the RES scenario, without (BL) and with a strategic reserve (SR)

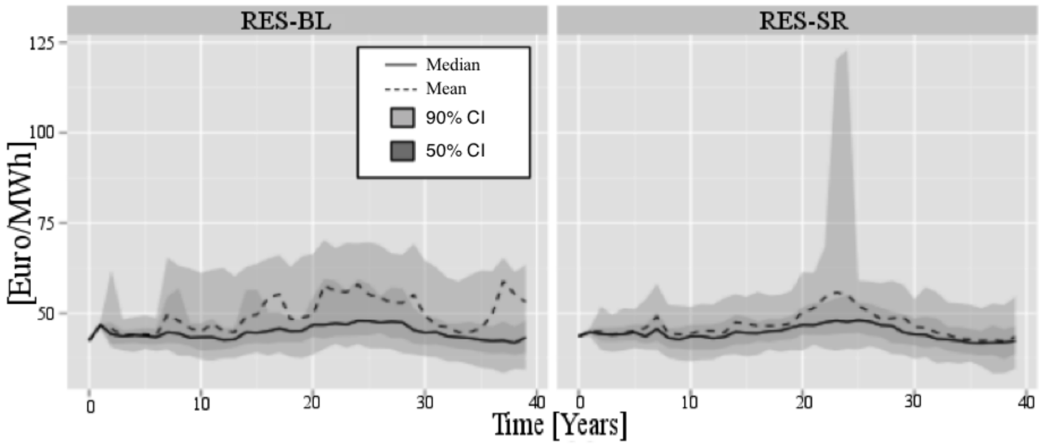

Figure 3.16: Electricity prices in a dynamic scenario with an increasing share of RES, without (left) and with (right) a strategic reserve

Comparing the overall effectiveness of a strategic reserve in a thermal-only scenario with a scenario with increasing RES, it is clear that the reserve performs better in a thermal-only scenario, with a higher supply ratio and fewer shortage hours. However, the relative improvement is greater in the case with high share of renewable energy in the generation portfolio. While the reserve becomes less effective in scenarios with renewable energy, the simulation results show that a strategic reserve can provide a viable alternative for maintaining security of supply during the early stages of this transition to low-carbon technologies at a relatively low cost to consumers. These results pertain to a closed market, however; the effects of a reserve will 'leak' away across borders in strongly interconnected markets. These cross-border effects are presented in a later chapter of this thesis.

3.5.4 Impact of the dimensions of the strategic reserve on its effectiveness

In order to explore the impact of the size and the dispatch price of the strategic reserve on reliability, the model is run with different price and volume combinations. This analysis also provides insight into possible options for improving the effectiveness of the strategic reserve as the share of renewable energy grows. Scenario runs were carried out for the RES-SR scenario by changing either the price or the volume of the strategic reserve and Figure 3.17 shows the results. Within runs, the reserve parameters were kept constant. In the first case, illustrated by the left-side graphs in Figure 3.17, the reserve price was kept at 800 €/MWh and the reserve volume was varied between 2.5% and 20% of peak demand in increments of 2.5%. In the second case, illustrated by the right-side graphs in Figure 3.17, the reserve volume was fixed at 6% and the reserve price was varied from 200 €/MWh to 1800 €/MWh with increments of 200 €/MWh.

The impact of changes in the reserve dimensions on the net cost of the strategic reserve, on the average number of shortage hours and on the supply ratio, are illustrated in Figure 3.17. Increasing either the volume or the price of the reserve, while keeping the other variable constant, causes the supply ratio to increase and shortages to decline. The impact on the cost of the strategic reserve is less clear. The effectiveness of the strategic reserve is more sensitive to changes in volume than to changes in dispatch prices. The number of shortage hours comes close to zero with a reserve size of 10%. The trends shown in Figure 3.17E indicate that an increase in the volume of capacity contracted into the reserve leads to higher utilization of the strategic reserve, causing prolonged periods of high prices and thus increasing the final cost to consumer by more than when the reserve price is increased (see Figure 3.17D and 17I).

When the reserve volume is increased, the number of hours that the reserve is dispatched per year increases at more than a linear rate, as it crowds out other generators (Figure 3.17E.). The cost of contracting the reserve to the system operator increases at first, but begins to decline when the contracted reserve volume is beyond a certain level (Figure 3.17C). At this point, the revenue earned by the operator is higher than the cost of contracting additional capacity, leading to a reduction in the overall cost of contracting the reserve to the operator. A reserve volume that exceeds the optimal level leads to a reduction in the cost incurred by the operator for contracting the reserve. However, the increased reserve dispatch duration due to the higher reserve volume causes a considerable rise in the cost to consumers, which means that a very large reserve volume would not be an efficient solution from the consumer-cost perspective. An excessive reserve volume, given the reserve dispatch price (P_{SR}), constitutes an abuse of market power to raise wholesale electricity prices beyond what is needed to attract investment; it recovers more cost but negatively affects consumer welfare. The cost of the reserve is lowest at a reserve volume of 15% of peak demand. Even then, the net cost of the strategic reserve is only about 1% of the average wholesale electricity price. Increasing the reserve price is not as effective in reducing shortages or increasing the supply ratio, as is indicated by Figure 3.17 (Figure 16A, 16F, 16B and 16G).

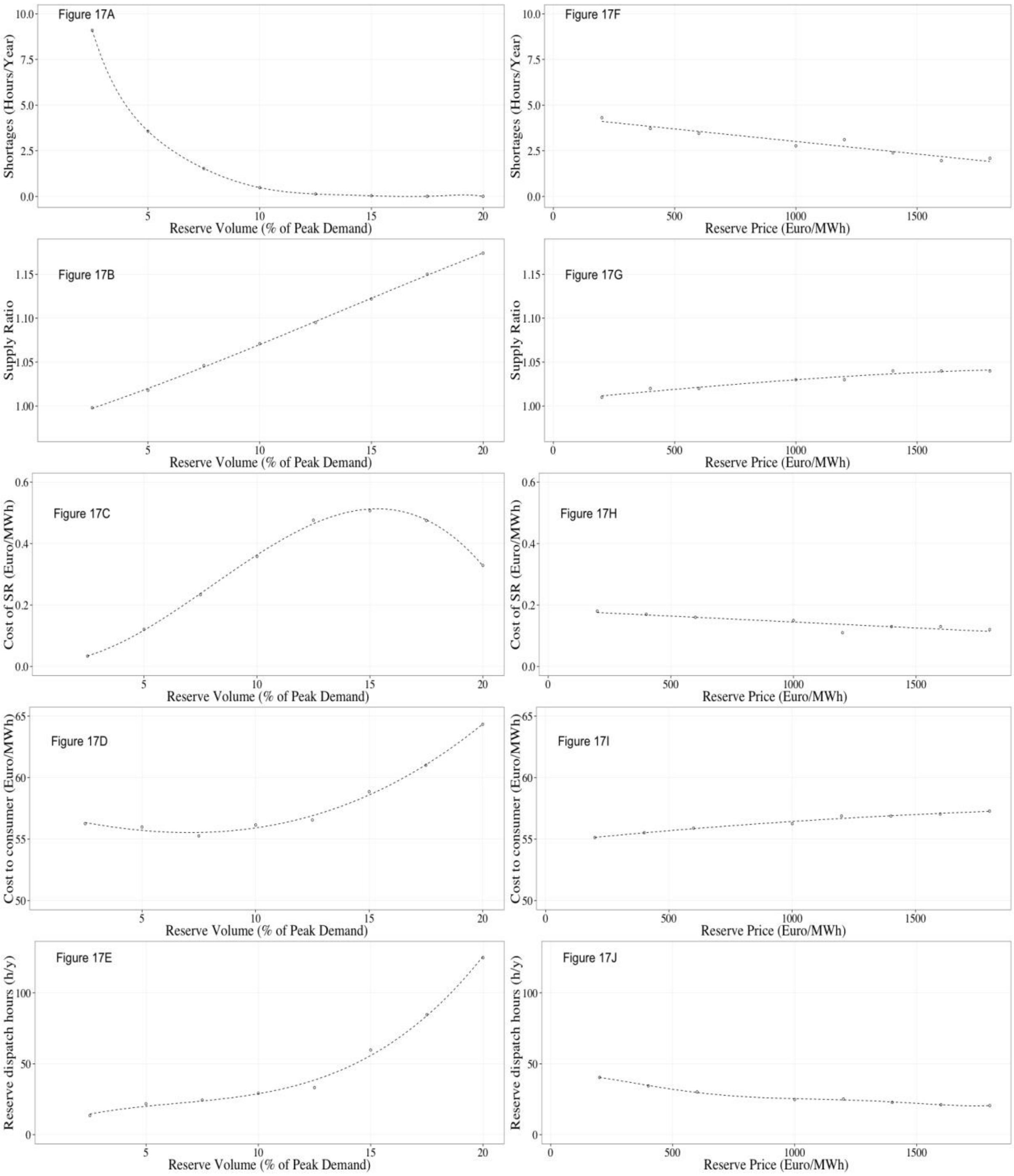

Figure 3.17: The effects of different reserve volumes (left side) and dispatch prices (right side) on the average number of shortage hours, the supply ratio, the cost of the reserve, the cost to consumer and reserve dispatch hours.

It is observed from Figure 3.17 (Subfigure D1) that in the presence of growing RES, the cost to consumers is lowest when the reserve volume is around 7.5%. This is higher than the 6% volume that was calculated for a thermal-only scenario with the same reserve price. This indicates that a larger reserve volume would be required in order to minimize the cost to consumer in the presence of growing RES as compared to a thermal-only scenario.

A comparison of the results from the design parameter analyses indicates that increasing the reserve volume would be the most effective way of improving the effectiveness of a strategic reserve in a scenario with a growing share of RES. However, a large strategic reserve could conflict with the intended neutrality of the system operator vis-à-vis market parties.

3.5.5 The effectiveness of a strategic reserve in the event of a demand shock

A demand shock is modeled to test the ability of a strategic reserve to cope with extreme events. The simulated demand trajectory is shown in Figure 3.18 After 14 years of 1.5% demand growth, the system experiences a sudden drop in demand, followed by a zero growth for several years. These trends are still the averages of 120 runs; individual runs may deviate significantly. Eventually, in the last 11 years of the simulation, demand grows again at 1.5%. This scenario simulates the impact of the 2008 economic crisis in electricity demand in Western Europe, with the assumption that demand growth eventually will return to its pre-crisis level.

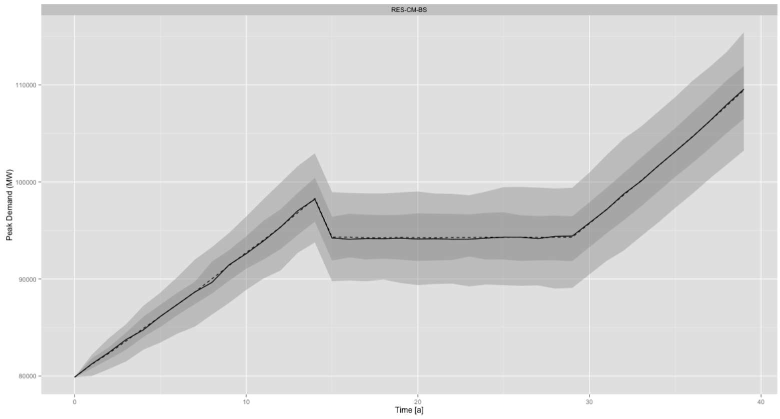

Figure 3.18: Peak demand trend in scenarios with a demand shock

The supply ratio in the scenario with a demand shock that has been described above is presented in Figure 3.19. The sudden drop in demand leads to a reduction in the hours with reserve dispatch price reducing the investment incentive in new capacity. It also causes reduction the strategic reserve size in MW (value of which is based on the peak demand). Thus some power plants that are dependent on the revenues from the strategic reserve to remain available do not get contracted in the reserve. As the demand growth does not rebound, these power plants are gradually decommissioned. The dampening of investment incentive along with the decommissioning of existing power plants causes an overshoot in dismantling. The overshoot in dismantling leads to an increase in the strategic reserve dispatch hours. There is also an increase in shortage hours. This reinforces the investment cycle. Thus a strategic reserve may not be able to dampen investment cycles in the event of a demand shock.

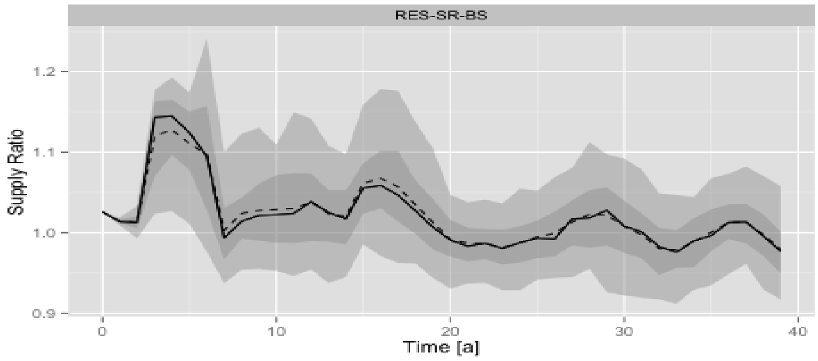

Figure 3.19: Supply ratio in a scenario with a demand shock.

3.6 Conclusions

A model of a strategic reserve to analyze its dynamic effectiveness without and with a large share of renewable energy in the portfolio is presented. A method for determining the parameters of a strategic reserve based on Stoft (2002) is presented. A strategic reserve can have a stabilizing effect on an electricity market in a reasonably cost-effective manner, depending on the scenario. Early investment incentives improve the supply ratio and therefore reduce shortages.

In the model, a strategic reserve increases the net cost of electricity supply to consumers in a scenario without variable renewable energy, but in the presence of a high volume of variable renewable energy, it reduces the cost to consumers because it has a stabilizing effect on investment cycles in thermal power generation capacity.

Two problems with a strategic reserve are found. First, there is a risk of extended periods of high average electricity prices if the reserve fails to attract sufficient investment. For instance, imperfect investment decisions, for example due to uncertainty regarding future demand growth, may still cause an investment cycle, resulting in high average electricity prices in some years. Second, the effectiveness of the reserve with respect to maintaining generation adequacy appears to decrease as the share of variable renewable energy grows. In the latter case, the reserve may need to be redesigned or replaced by an alternative capacity mechanism.

The effectiveness of the reserve may be improved by increasing its volume. Increasing the dispatch price is less effective. A larger volume also may improve the reserve’s cost recovery rate, given a certain reserve dispatch price, but this would reflect an abuse of the reserve’s market power and reduce consumer welfare. The long-term model of a strategic reserve also reveals what is described as the dismantling paradox. When a reserve contains old units that should be dismantled, the presence of the reserve may cause undue life extension, whether these units are contracted in the reserve or not.

4. Yearly Capacity Market

This chapter is based on Bhagwat et al. (2016b) with minor modifications.

4.1 Introduction

In this research, the effectiveness of a capacity market with and without a growing share of renewable energy is analyzed. A capacity market is a quantity-based capacity mechanism in which the price of capacity is established in a market for capacity credits. In a capacity market, the consumer, or a party on his behalf, is obligated to purchase capacity credits equivalent to the sum of its expected peak demand and a reserve margin. Capacity credits can be allocated in auctions or via bilateral trade between consumers and producers (Cramton et al., 2013; Rodilla and Batlle, 2013). The reserve margin requirement is expected to provide a stronger and earlier investment signal, thereby ensuring adequate generation capacity and more stable electricity prices.

The effectiveness of the capacity market under different demand growth scenarios and design considerations is also analyzed. As the presence of a capacity market may or may not incentivize growth in particular technologies in the supply mix, the impact of capacity markets on the share of different technologies in the supply mix is assessed.

A variety of capacity market designs have already been implemented across the world. The design of the capacity market is based on the installed capacity market (ICAP) that is organized by the New York Independent System Operator (NYISO) in the United States and is implemented as an extension to the EMLab-Generation agent based model.

In the next section, the implementation of a capacity market in this model is described. Section 3 describes the scenarios that are used. In Section 4, the results are presented from the simulation of a capacity market implemented under various conditions. The conclusions are summarized in Section 5.

4.2 Model description

4.2.1 The capacity market module

The capacity market module in EMLab-Generation is modeled with a few simplifications after the NYISO-ICAP model. The NYISO market was chosen for its relatively simple design. Moreover, it was one of the first capacity markets to be established in the United States and may be considered as an example of a capacity market that is arguably meeting its policy goals. Moreover, it is projected that no new resource requirements would be necessary in NYISO region till 2018 (Newell et al., 2009).

In the NYISO-ICAP, generators offer unforced capacity (UCAP) (NYISO, 2013a, 2013b) in a series of auctions. The auctions are conducted annually for the following year. The ISO contracts capacity on behalf of load serving entities (LSEs); thus, consumers participate automatically. A sloping demand curve is utilized. Consumers are provided opportunity to correct their positions during the year via the monthly spot auctions and capability period auctions. In each year there are two capability periods, summer capability period (May 1st - Oct 31st) and winter capability period (Nov 1st - April 30th) (Bhagwat et al., 2016a; NYISO, 2014). The LSEs are obligated to purchase capacity credits equivalent to the minimum unforced capacity (UCAP) assigned to them (Harvey, 2005; NYISO, 2013a, 2013b). The value of unforced capacity is calculated as the product of the Installed Reserve Margin (IRM) and the forecasted peak demand (NYISO, 2013b). The regulator calculates the IRM so as to achieve a loss of load expectation of once in 10 years. NYISO allows bilateral capacity contracts and imports to participate on the capacity market subject to certain rules and regulations. A detailed description of the market rules is given in (NYISO, 2013b; Spees et al., 2013).

In the capacity market that is modeled in EMLab-Generation, the capacity for the coming year is traded in a single annual auction and is administered by an agent called the capacity market regulator. The user sets the IRM, capacity market price cap and parameters for generating the slope of the demand curve.

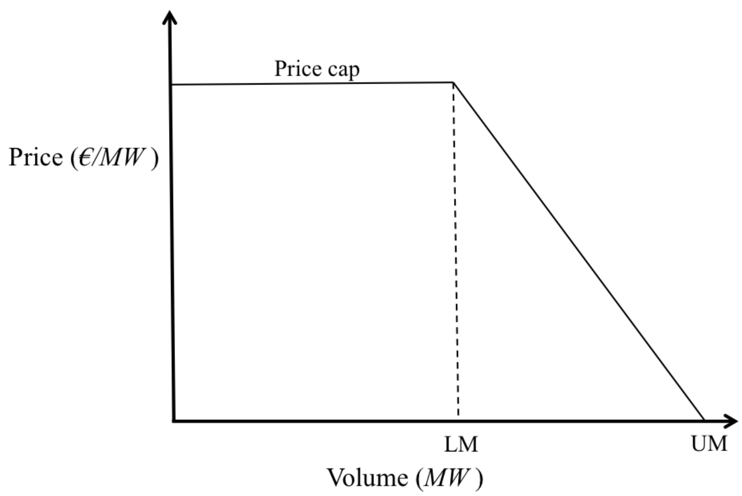

Figure 4.1: Illustration of a sloping demand curve

The regulator calculates the demand requirement (*D_r*) for the current year based on the IRM (*r*) and the expected peak demand (*D_{peak}*). Expected peak demand is forecast by extrapolating past values of peak demand using geometric trend regression over the past four years. The demand requirement is calculated with the following equation.

$$D_r = D_{peak} \times (1 + r)$$

(1)

A sloping demand curve is modeled for the capacity market like in the NYISO-ICAP and PJM-RPM capacity markets. These markets implement sloping demand curves to provide more predictable revenues to generators and to lower consumer costs by reducing price volatility (Hobbs et al., 2007). When a sloping demand curve is implemented, changes in the offered volume of capacity result in small price changes, thus stabilizing capacity market prices (Pfeifenberger et al., 2009). As is illustrated in Figure 4.1, the sloping demand curve consists of two lines: a horizontal line at the capacity market price cap (P_c) and a sloping line intersecting the horizontal line and the X – axis. The slope and position of the sloped line are dependent upon three user-defined variables, namely, the demand requirement (D_r), the lower margin (*lm*) and the upper margin (*um*). The lower and upper margins are administratively set maximum flexibility boundaries above and below the IRM. The sloping line intersects the horizontal line at Point ($X = LM$, $Y = Pc$). The slope of the line is calculated using the following equation

$$m = \frac{P_c}{LM - UM} \tag{2}$$

In which:

$$UM = D_{peak} \times (1 + r + um)$$

$$LM = D_{peak} \times (1 + r - lm)$$

The supply curve is based on the Price (*€/MW*) – Volume (*MW*) bid pairs submitted by the power generators for each of their active generation units. The agents calculate the volume component of their bids for a given year as the generation capacity of the given unit that is available in the peak segment of the load-duration curve. A marginal cost-based approach is used to calculate the bid price. For each of power plant, the power producers calculate the expected revenues from the electricity market. If the generation unit is expected to earn adequate revenues from the electricity market to cover its fixed costs operating and maintenance costs (in other words, its costs of staying online), the bid price is set to zero, as no additional revenue from the capacity market is required to remain operational. Units that are not expected to make adequate revenues from the energy market to cover their fixed costs of remaining online, bid the difference between the fixed costs and the expected electricity market revenue, the minimum revenue that would be required to remain online.

The capacity market-clearing algorithm is based on the concept of uniform price clearing. The bids submitted by the power producers are sorted in ascending order by price and cleared against the above-described sloping demand curve. The units that clear the capacity market are paid the market-clearing price. While making investment and dismantling decisions, the power generators take into account the expected revenues from the capacity market.

4.3 Scenarios

In this section, the scenarios for the simulation runs are discussed. Every scenario consists of 40 time steps of one year each that are run 120 times, Monte Carlo fashion, with identical starting conditions. In the reference scenario, the model is run without a renewable energy policy in order to assess the effectiveness of a capacity market without possible effects from a renewable energy policy. The other scenarios do involve a renewable energy policy so as to address the core research question regarding the effectiveness of a capacity market in regions with a growing share of renewables in their supply mix. The scenario settings are described in Table 4.1. TM indicates a thermal-only, as opposed to a scenario with a RES policy. BL indicates the baseline of no capacity market; the presence of a capacity market is indicated with CM.

A single electricity market without interconnections is considered. On the supply side, the electricity market consists of four identical energy producers. At the start of the simulation run, their power generation portfolios consist of four conventional generation technologies: OCGT, CCGT, coal and nuclear power. The energy producers may consider investing in other available technologies while making their investment decisions during the simulation period. The supply mix is roughly based on the portfolio of thermal generation units in Germany (Eurelectric, 2012) (See Table B.0.3). A renewable energy policy that causes rapid growth in the share of intermittent renewable energy resources over the period of the simulation is introduced. The renewable energy trends are based on the German renewable energy action plan (NREAP, 2010) until 2020 and extrapolated after then.

The price trends for the various fuels are modeled stochastically, based on a triangular trend distribution. (See Appendix A). The coal and gas prices are based on fossil fuel scenarios published by the Department of Energy & Climate Change (2012) (Department of Energy & Climate Change, 2012). The biomass prices are based on Faaij (2006) (Faaij, 2006). The initial load-duration function is based on 2010 ENTSO-E data for Germany. A demand growth of 1.5% is introduced, based on a mean-reverting probability distribution. A value of lost load (VOLL) value of 2000 €/MWh is used. This is based on (Anderson and Taylor, 1986; Baarsma and Hop, 2009; Leahy and Tol, 2011; Linares and Rey, 2013; Pachauri et al., 2011; Wilks and Bloemhof, 2005).

The scenario (RES-CM) consists of a capacity market with a capacity maximum price of 60 000 €/MW per year. The capacity market regulator requires a reserve margin of 9.5%. This is based on the NYISO-ICAP reserve margin requirement, which is lowered to reflect the fact that generation outages are not modeled. Lower and upper margins of 2.5% are introduced to generate a sloped demand curve.

Table 4.1: Scenario parameters

Scenario	RES	Capacity Market
TM-BL	-	-
TM-CM	-	✓
RES-BL	✓	-
RES-CM	✓	✓

The following indicators are used for the evaluation of the effectiveness of the capacity market:

- The average electricity price (€/MWh): the average electricity price over an entire run.
- Shortage hours (hours/year): the average number of hours per year with scarcity prices, averaged over the entire run.

- The supply ratio: the ratio of available supply over peak demand (MW/MW).
- The cost of the capacity market (€/MWh): the cost incurred by consumers for contracting the mandated capacity credits from the capacity market, divided by the total units (MWh) of electricity consumed.
- Cost to consumers (€/MWh): the sum of the electricity price, the cost from the capacity market and cost of renewable policy (if applicable) per unit of electricity consumed[6].

4.4 Results and analysis

4.4.1 Overview

Figure 4.2 provides an overview of the results of the simulation runs. The results are also presented numerically in Table 4.2.

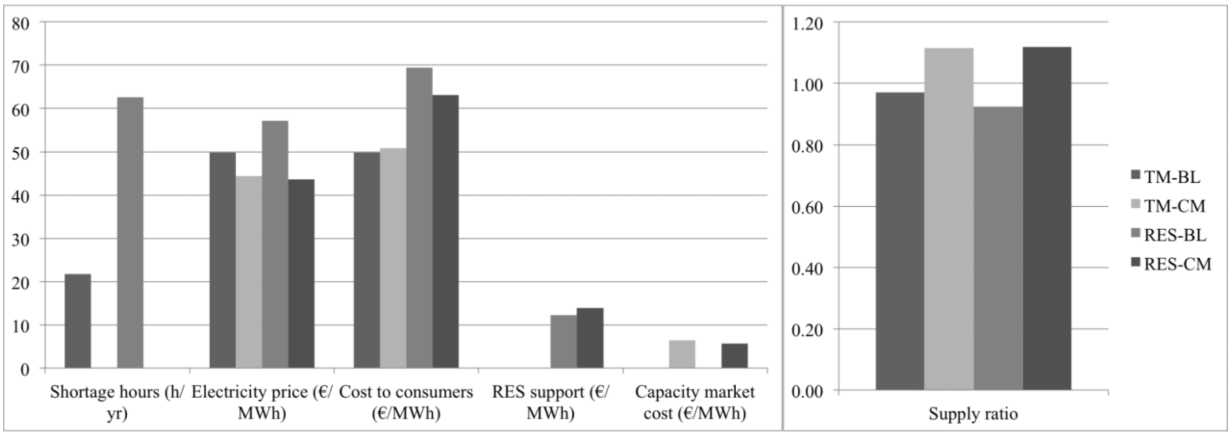

Figure 4.2: Comparison of indicators for the TM and RES scenarios.

Table 4.2: Comparison of indicators for scenarios with and without RES policy implemented.

Scenario	Shortage Hours (h/yr)	Supply Ratio	Electricity Price (EUR/MWh)	RES Support (EUR/MWh)	Capacity Market Cost (EUR/MWh)	Cost to Consumer (EUR/MWh)
TM-BL	21.7	0.97	49.83	0	0	49.8
TM-CM	0.00	1.11	44.36	0	6.5	50.8
RES-BL	62.6	0.92	57.21	12.20	0	69.4
RES-CM	0.00	1.12	43.65	13.87	5.6	63.1

At the start of the simulation run in the baseline (TM-BL and RES-BL) scenario a decline in the supply ratio is observed. This is caused by the dismantling of excess (idle and unprofitable) capacity that exists in the system due to the high supply ratio set in the initial scenario settings. Moreover, demand response is not considered in this study. The presence of

[6] Note that this includes the cost of outages, because in our model the electricity price rises to the VOLL during shortages.

even small quantity of demand response would lead to considerable reduction in shortage hours observe in the baseline scenarios.

4.4.2 The effectiveness of a capacity market in the absence of a renewable energy policy

The effectiveness of a capacity market is tested in the absence of renewable energy policy (TM-CM) by comparing it to the baseline case without a capacity market (TM-BL). In the model, the capacity market exceeds the adequacy goals: an average supply ratio of 1.11 is observed in the presence of a capacity market, which is 1.5% higher than the adequacy target of 9.5%. (See Figure 4.3.) In this figure and in the ones like it, the mean is indicated with a solid line, the average with a dashed line, the 50% confidence interval with a dark grey area and the 90% confidence interval with the lightly shaded area. The average capacity price is 36.5 k€/MW. The overshoot in adequacy that is observed can be attributed to configuration (price cap and slope) of the demand curve used in this analysis. The capacity market clears at a level where it becomes economically viable for excess idle capacity above the targeted IRM to remain available. The higher supply ratio that is induced by the capacity market leads to a reduction in the average number of shortage hours from 21.7 hours/year in the baseline scenario to nil. The electricity price is 11% lower and volatility is also reduced, as can be seen in Figure 4.4. The net cost to consumers increases slightly (from 49.8 €/MWh in TM-BL to 50.1 €/MWh in TM-CM), as the lower electricity prices are offset by the capacity payments.

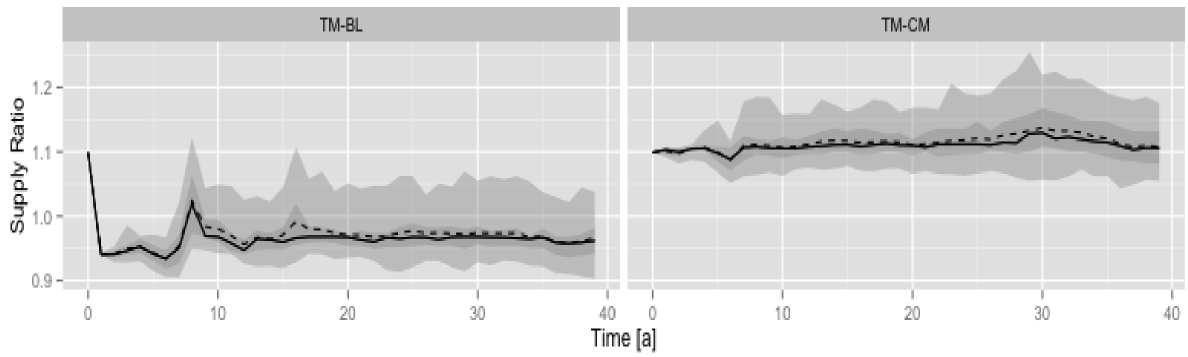

Figure 4.3: Supply ratio in a scenario without a renewable policy without (left) and with (right) a capacity market

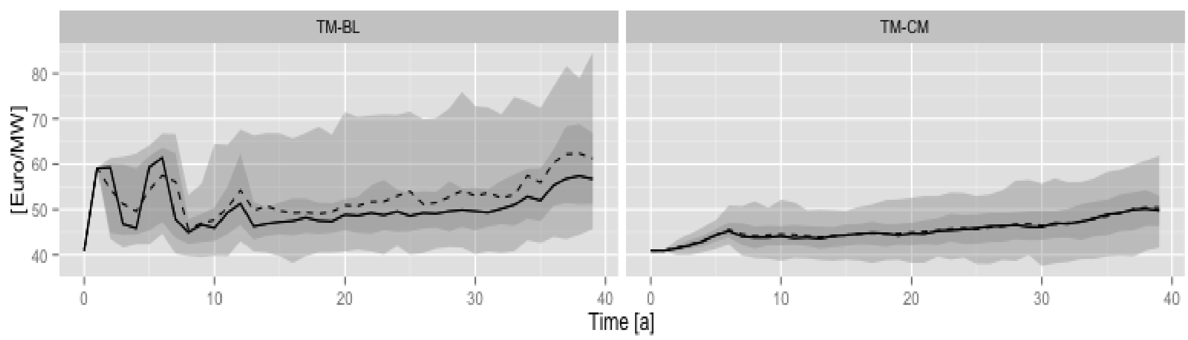

Figure 4.4: Electricity prices in a scenario without a renewable policy, without (left) and with (right) a capacity market

The main impact of the implementation of a capacity market on the generation mix is a strong increase in 'peaker' plants: on average there is 19.9 GW of OCGT capacity in the scenario with a capacity market as compared to 6.1 GW of OCGT in the baseline scenario (TM-BL). This is due to the low utilization rate of the last plants in the merit order in the presence of a capacity market. The income from the capacity market is sufficient for OCGT capacity to remain online even when these units have very little or no income from the electricity market. Figure 4.5 illustrates the development of OCGT generation capacity over the simulation. (Each data point indicates the average OCGT capacity at that particular year calculated over 120 Monte Carlo runs.).

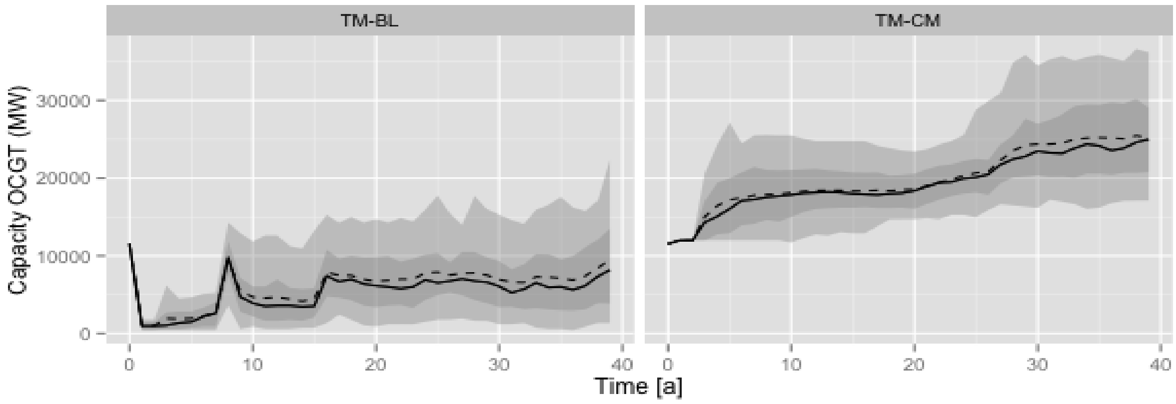

Figure 4.5: Development of OCGT installed capacity

4.4.3 The effectiveness of a capacity market with a growing share of renewables

The presence of intermittent renewable energy generation in the supply mix reduces the supply ratio from 0.97 to 0.92 in the baseline scenario. As a result, the average numbers of hours of supply shortage more than double, from 21.7 to 62.6 hours/year. The reason is that the presence of a high share of renewables in the system reduces the number of dispatch hours and therefore the revenues of thermal generators. This leads to a reduction in investment and causes the dismantling of some existing power plants that no longer receive adequate revenue from the electricity market. The higher number of shortage hours offsets the reduction in cost to consumer due to the lower electricity prices caused by the renewable resources.

A capacity market is able to compensate for this effect. A supply ratio of 1.12 is maintained fairly consistently in the model (Figure 4.6), which is 2.5 - percentage points higher than the adequacy target of 9.5%, also in high RES scenarios. This overshoot indicates that the current configuration of the capacity market provides greater incentive than what is required to maintain the adequacy target (IRM). The average capacity market clearing price is 31.6 k€/MW per year. It is also observed that the capacity market is less volatile in terms of capacity prices in the presence of renewables as compared to the TM-CM scenario and that the average capacity price is lower (See Figure 4.10). However, the additional cost of RES support leads to a higher net cost to consumers in RES scenarios as compared to the thermal only scenarios.

In the model, the presence of additional capacity eliminates shortages completely (from 62.6 hours/year to nil). Consequently, the average electricity price declines by 24% in RES-

CM, as compared to RES-BL. A significant reduction of electricity price volatility is also observed in RES-CM (see Figure 4.7).

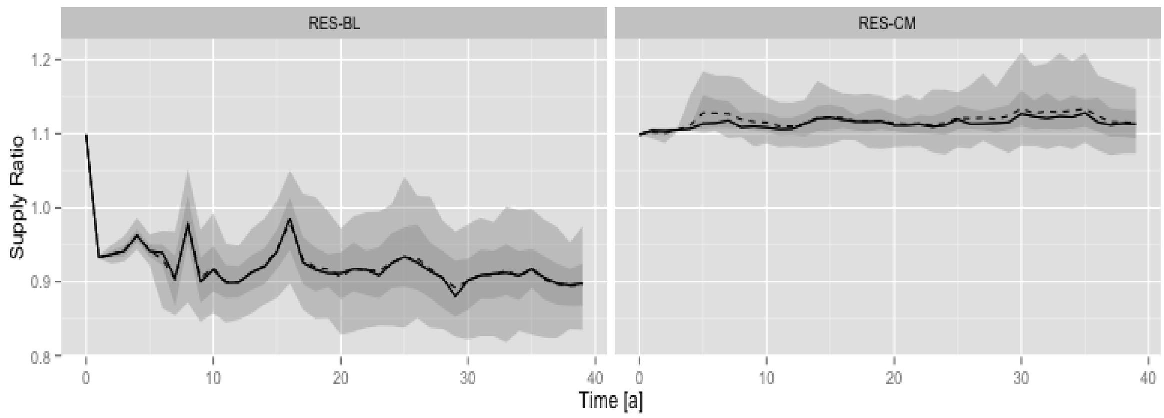

Figure 4.6: Supply ratio in the growing share of renewables without (left) and with a capacity market (right)

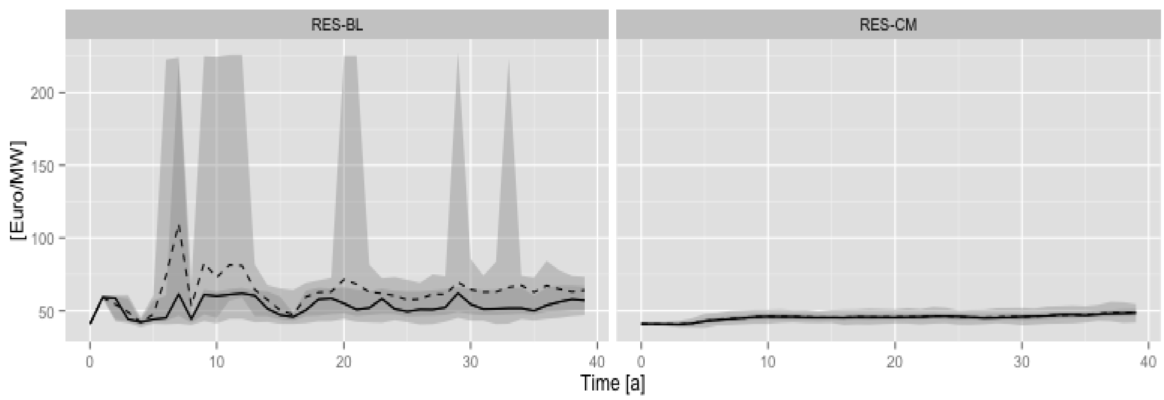

Figure 4.7: Electricity price in scenarios with growing share of renewables without (left) and with a capacity market (right)

The total cost to consumers is 9% lower in the presence of a capacity market in the high-RES scenario. To understand this reduction, the impact of a capacity market on electricity prices and the cost of renewable energy policy are analyzed. The presence of a high supply ratio leads to a steep decline in shortages, which has a substantial damping effect on the electricity prices. However, the lower electricity prices increase the need for RES subsidy by 14% due to the lower electricity market revenues of the renewable generators. The cost savings from the electricity market are larger than the costs of the capacity market plus the higher renewable energy subsidy. The net cost to consumers in the presence of a capacity market is lower than in the baseline scenario. Thus the increase in consumer welfare due to reduction in shortages offsets the cost of maintaining a higher supply ratio.

In order to provide insight in the effect of renewable energy on the system, Figure 4.8 illustrates the shares of different technologies in the generation mix of the system in both a case without and with a capacity market (The figures show the average share of generation (in *MWh*) from different technologies over 120 Monte Carlo runs.). It can be observed from Figure 4.8 that the presence of a capacity market does not distort the supply-mix. In the scenario with a capacity market (RES-CM), the average annual electricity generation is *201*

GWh more than in the baseline scenario (RES-BL). The additional supply eliminates the shortages that occur in the baseline scenario RES-BL.

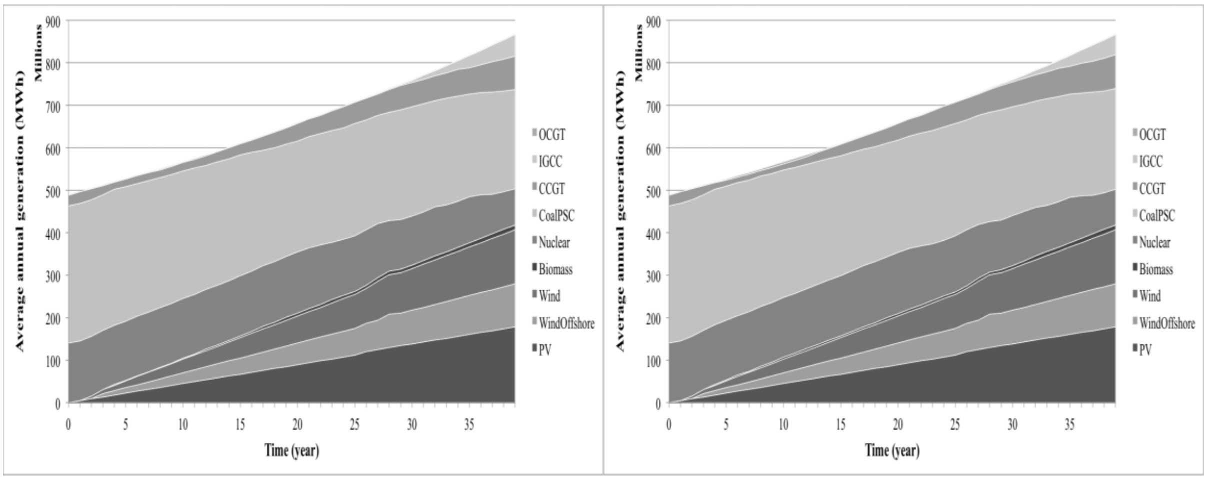

Figure 4.8: Average shares of generation technologies in the energy supply mix in a scenario without (left) and with a capacity market (right)

In this scenario, the capacity market mainly results in more investment in 'peakers'. On average, the volume of OCGT capacity rises from 5.4 GW in the baseline scenario to 28 GW in the presence of a capacity market. (See Figure 4.9.) The additional income from the capacity market is sufficient for additional OCGT capacity to remain online even when these units have very little or no income from the electricity market. Due to the high share of renewables in the system, thermal units operate fewer hours than in a scenario without renewables (TM). This makes OCGT plant more attractive for peak capacity. However, it also appears that the capacity requirement is set too high, given that plant outages are not simulated. Too high a margin would lead to investment in plant that hardly ever runs, in which case the choice for OCGT, as the technology with the lowest capital cost, is logical. Figure 4.9 illustrates the development of OCGT capacity over the length of the simulation (each data point indicates the average OCGT capacity at that particular year calculated over 120 Monte Carlo runs).

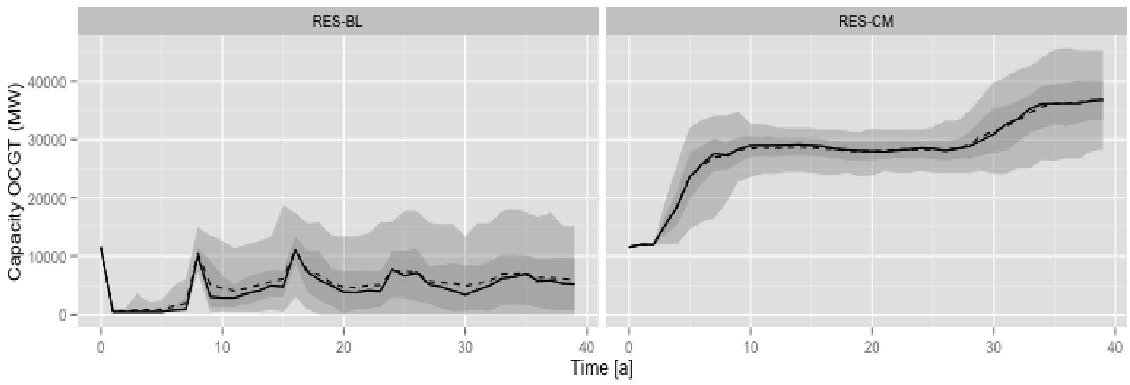

Figure 4.9: OCGT development in presence of high share of renewables

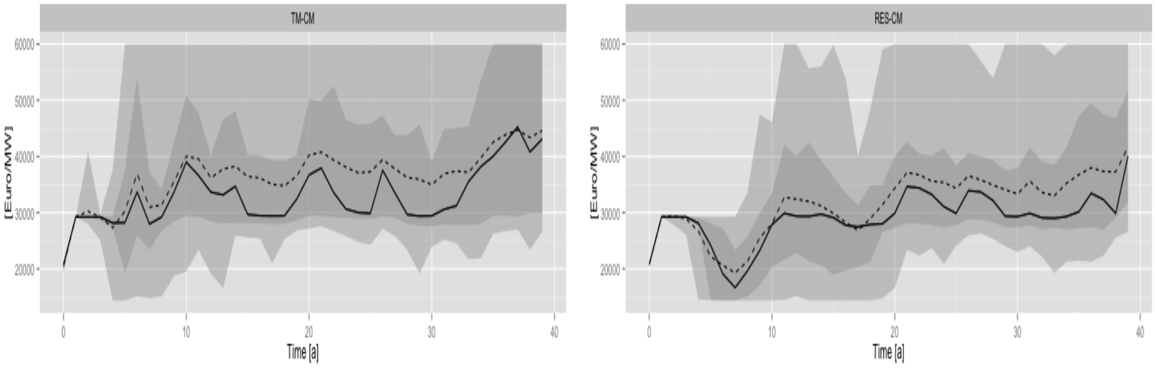

Figure 4.10: Capacity market prices in scenarios without (left) and with a renewable energy policy (right)

The comparison of the scenarios with and without a growing share of renewables suggests two more observations. In neither scenario is the remuneration from the capacity market sufficient to stimulate investment in nuclear power. This suggests that countries that desire new investment in nuclear power will need to implement a support policy. This is corroborated by the current situation in the UK, which has a feed-in tariff for nuclear policy in addition to its capacity market.

Secondly, the average capacity market-clearing price is lower when there is more renewable energy generation capacity in the electricity system. As renewable power producers are allowed to offer the available capacity at peak for their renewable resources to the capacity market, the presence of renewable energy generation capacity dampens capacity market prices as renewables push out some of the expensive peak capacity from the capacity market (Figure 4.10). Clearly, this effect depends on the assessment of the contribution of variable renewable energy to peak demand and on the way that renewable energy is treated in the capacity market.

In order to understand the sensitivity of the model results to the assumed (modeled) peak contribution of renewable energy generators, the model was also run in a configuration in which the contribution of intermittent renewables to the peak segment was set to zero and intermittent renewable energy generators therefore also do not receive capacity credits. A modest impact on the model results is observed. In the baseline scenario with zero peak contribution of RES, higher average electricity prices are observed as compared to *RES-BL*, which is expected due to the reduction in available peak capacity. The implementation of a capacity market in a configuration with zero peak contribution of RES results in a supply ratio that is similar to the *RES-CM* scenario. There is an increase in net cost to consumers, as no capacity from the renewable resources is traded on the capacity market (peak available capacity of all RES is zero), leading to a higher capacity-clearing price. The results of these runs are presented in Figure 4.11.

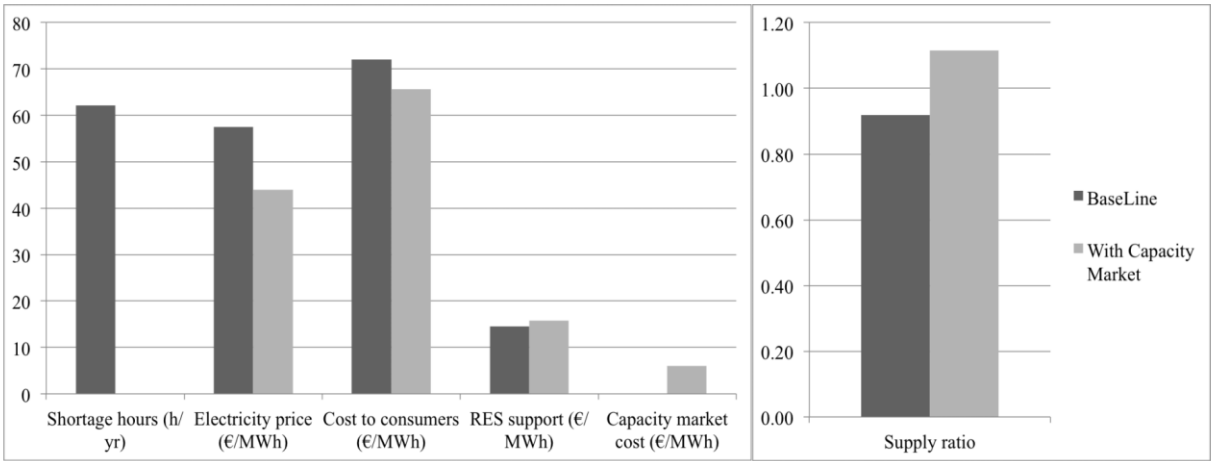

Figure 4.11: Comparison of the scenarios with zero contribution of renewables to the peak

A strategic reserve is one of the possible alternatives for a capacity market. In earlier work, the effectiveness of a strategic reserve in the presence of a growing share of renewable energy in the supply mix was analyzed (Bhagwat et al., 2016d). In order to compare the results from the two capacity mechanisms and to maintain the consistency of all scenario settings, the model was run with a strategic reserve, while all other scenario parameters were kept the same as in RES-BL. In the model, both capacity mechanisms reduce the net cost to consumer in the presence of imperfect (myopic) investment. However, unlike the strategic reserve, the effectiveness of the capacity market in providing the required reserve margin does not decrease with an increase in share of intermittent renewable energy (See Figure 4.12). A capacity market is less prone to investment cycles.

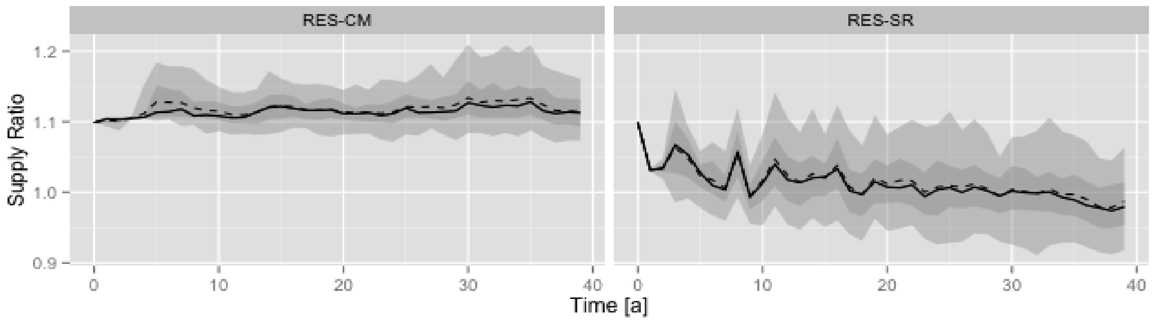

Figure 4.12: Supply ratio in the growing share of renewables with a capacity market (left) and with a strategic reserve (right).

4.4.4 Sensitivity analysis

As a sensitivity analysis, the effectiveness of a capacity market with respect to differences in electricity demand growth and with a demand shock is assessed. The impact of changes in several capacity market parameters such as the targeted reserve margin, the capacity market price cap and the slope of the demand curve are also tested. The following table provides an overview of the scenarios for the sensitivity analysis.

Table 4.3: Scenario settings for sensitivity analysis

S. No.[7]	Demand growth rate (%)	IRM (%)	Capacity market cap (k€/MW)	Upper margin (%)	Lower margin (%)
1	-0.5	9.5	60	2.5	2.5
2	0				
3	1.5				
4	3				
5	1.5	6	60	2.5	2.5
6		9.5			
7		12			
8		15			
9		18			
10	1.5	9.5	40	2.5	2.5
11			60		
12			80		
13			100		
14			120		
15	1.5	9.5	60	2.5	2.5
16				5	5
17				7.5	7.5

4.4.4.1 The impact of demand growth on the effectiveness of a capacity market

In order to evaluate the robustness of the capacity market with respect to demand growth uncertainty, model runs were performed with the four different demand development scenarios that are described in Table 4.3 (scenarios 1 to 4). All other parameters and scenario variables, including the growth of intermittent renewable sources, are the same as in the RES-CM scenario.

The ability of a capacity market to meet its adequacy targets is not strongly affected by the average demand growth rate. (See Figure 4.13.) A decline or no growth in demand combined with high renewable penetration exacerbates the missing money problem and thus leads to higher prices in the capacity market by thermal generators, as they require greater remuneration from the capacity market to cover their fixed costs. (See Figure 4.14.) Consequently, consumer costs are also higher as compared scenarios with medium or high growth rates. (See Figure 4.15.) A reserve margin of 11% is observed in the scenario with declining demand, which is higher than the required reserve margin target of 9.5% but within still the bounds of the upper margin (2.5%).

[7] Scenarios 3, 6, 11 and 15 are same as RES-CM

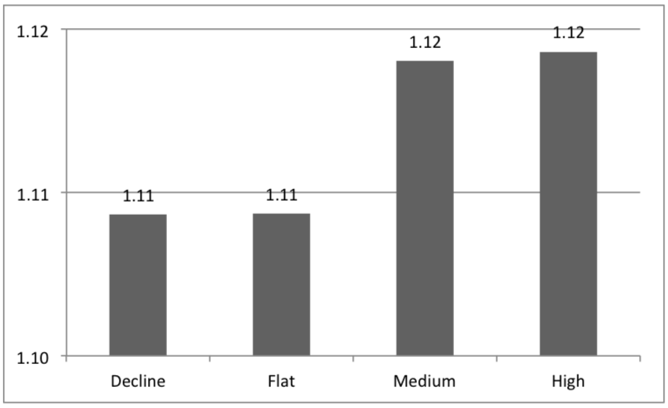

Figure 4.13: Supply ratios in different demand growth rate scenarios

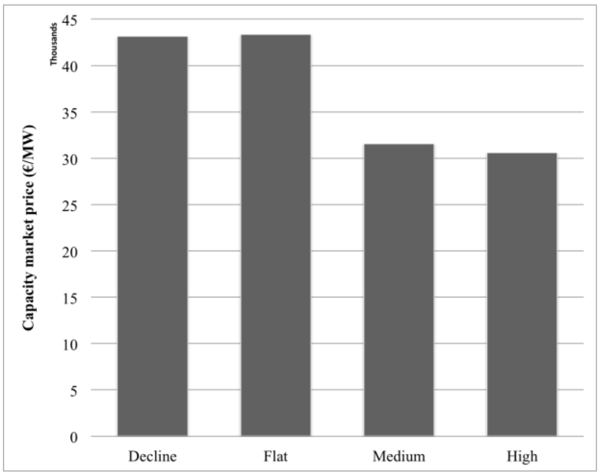

Figure 4.14: Capacity market clearing price in different demand growth rate scenarios

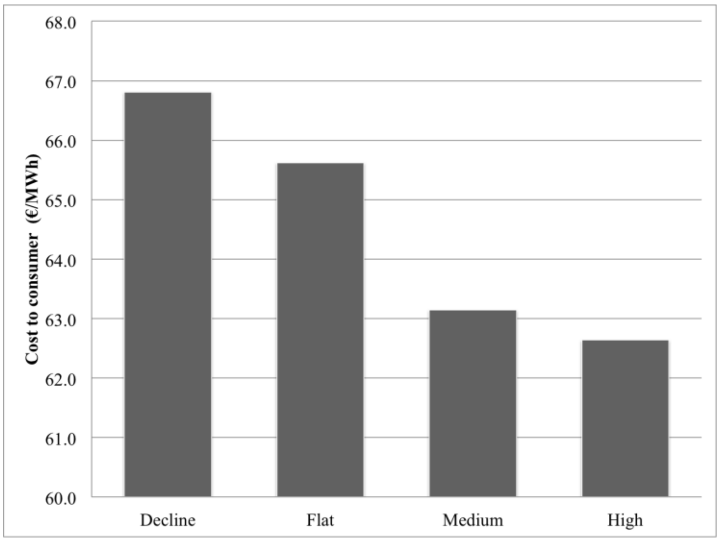

Figure 4.15: The cost to consumers in different growth rate scenarios

If demand growth is moderate or high, the revenues from the electricity market increase. This allows the generators to offer their capacity at a lower price to the capacity market, thereby damping capacity market prices and reducing the cost to consumers.

While the average demand growth rate affects the net cost to consumers, the capacity market is robust enough to provide an adequate reserve margin under widely varying demand growth conditions. In a declining demand scenario, more support from the capacity market is needed to maintain a given supply ratio. The opposite is true in a high demand growth scenario.

4.4.4.2 The impact of the reserve margin level on the effectiveness of a capacity market

The model is run with an *IRM* between 6% and 18% in increments of 3 percentage points. (See Table 4.3, Scenarios 5 -9.) All other parameters are kept the same as in the *RES-CM* scenario.

The results are illustrated in Figure 4.16. The IRM targets are met (See Figure 4.16). A higher IRM requirement leads to a higher capacity market clearing price (Figure 4.16) and hence to an increase in the net cost to consumers. A well-designed capacity auction can be used to achieve any reserve margin, but high reserve margins increase the cost to consumers without a significant increase in the security of supply. However, an IRM that is too low may not be able to handle any unforeseen events (such as demand shocks) and thus lead to an adverse impact on consumer costs.

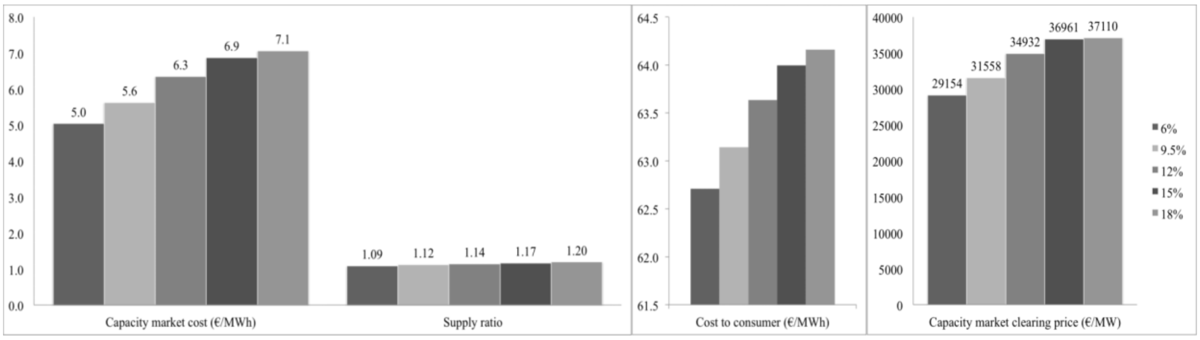

Figure 4.16: Indicators for scenarios with different capacity margin values

4.4.4.3 The impact of the capacity market price cap

The capacity market price cap is the value at which the capacity market clears in the event that the demand is higher than available supply in the capacity market. It is to be expected that it would affect the investment incentive. The communis opinio is that the price cap should be set somewhat higher than the cost of new entry (CONE) for the marginal generator (Cramton and Stoft, 2005; Hancher et al., 2015; NYISO, 2013b; Sioshansi, 2011). The level of the capacity market price cap is changed in increments of 20 k€/MW per year, while keeping all other scenario parameters the same as in the RES-CM scenario (Table 4.3, scenarios 10 – 14).

The capacity market price cap impacts the slope of the demand curve: a higher price cap makes the demand curve steeper. A steeper supply curve would have two implications. First, for the same volume of generation capacity, the market would clear at a higher price. Secondly, a steeper demand curve would make the capacity market price more sensitive to changes in capacity levels.

In this analysis, It is observed that the price cap has a significant impact on the price uncertainty of the capacity market prices, as can be observed in Figure 4.17 and Figure 4.18. In all scenarios, the required reserve margin targets are achieved. The supply ratio in scenario with a lower capacity price cap (40 k*€/MW)* is more stable but lower on average than in the scenarios with higher price cap values. See Figure 4.19. If the price cap is set too low, the capacity market may not be able to provide adequate incentive to attain the IRM target. Thus, a price cap close to the cost of new entry indeed provides the required adequacy and also minimizes price uncertainty in the capacity market. In the initial years of scenarios with price caps greater than 40 k*€/MW,* A dip in average capacity price is observed. This can be attributed to a high capacity clearing price at the starting year caused by the initial scenario set up. This causes an overshoot in generation capacity investment and thus a consequent dip in capacity market clearing price when this capacity comes becomes available (see Figure 4.18 and Figure 4.19).

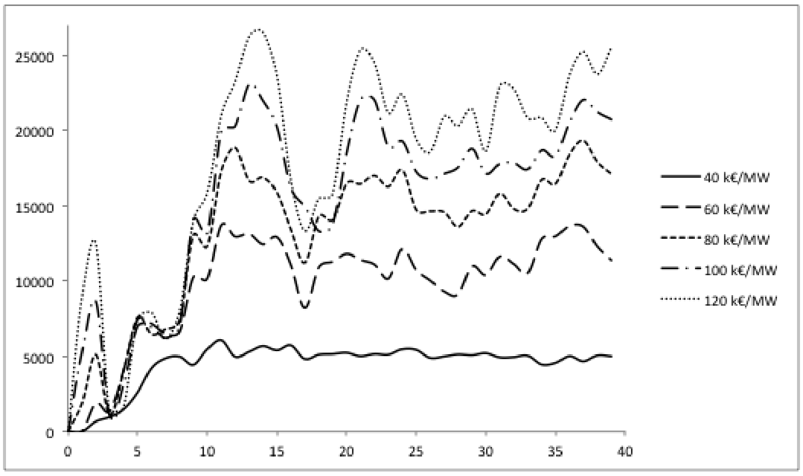

Figure 4.17: Standard deviation of capacity market prices in scenarios with different capacity price caps

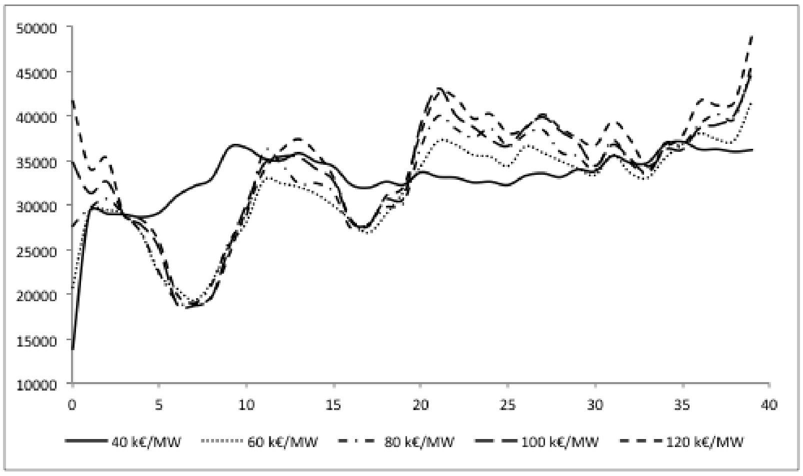

Figure 4.18: Average capacity clearing prices in scenarios with different capacity price caps

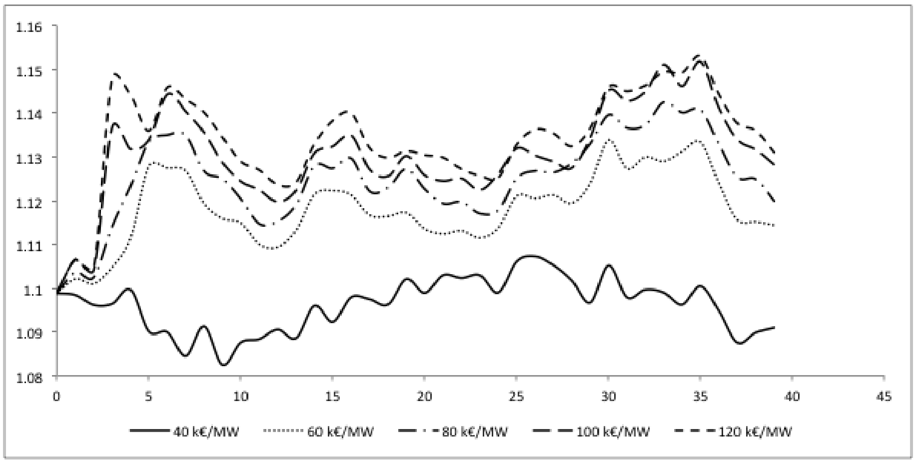

Figure 4.19: Average supply ratios in scenarios with different capacity price caps

4.4.4.4 The impact of the slope of the demand curve

Another design aspect that may affect the performance of a capacity market is the slope of the demand curve. As explained in Section 4.2.1, this is determined by the upper (*UM*) and lower (*LM*) margins. In this section, the *UM* and *LM* is increased in two increments of 2.5 percentage points. See scenarios 15 – 17 in Table 4.3. All other scenario parameters are kept the same as in the RES-CM scenario. As discussed before (e.g. Hobbs et al., 2007), a steeper demand curve makes the clearing price more sensitive to changes in demand and supply of capacity, as compared to a gentler slope. There is no significant difference in either the average supply ratio or the average capacity market-clearing price. However, the uncertainty of the capacity market prices declines with increasing values of the upper (*UM*) and lower (*LM*) margins (Figure 4.20).

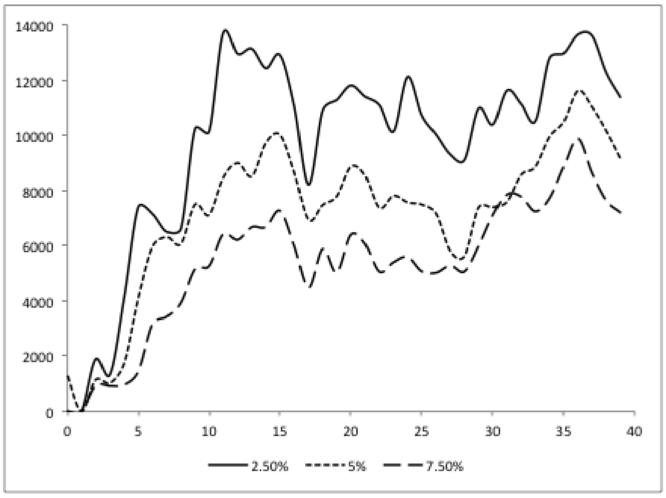

Figure 4.20: Standard deviation of capacity market clearing prices at different demand curve margin levels.

4.4.4.5 The effectiveness of a capacity market in the event of a demand shock

A demand shock is modeled to test the ability of a capacity market to cope with extreme events. The simulated demand trajectory is shown in Figure 4.21. After 14 years of 1.5% demand growth, the system experiences a sudden drop in demand, followed by a zero growth for several years. These trends are still the averages of 120 runs; individual runs may deviate significantly. Eventually, in the last 11 years of the simulation, demand grows again at 1.5%.

This scenario simulates the impact of the 2008 economic crisis in electricity demand in Western Europe, with the assumption that demand growth eventually will return to its pre-crisis level.

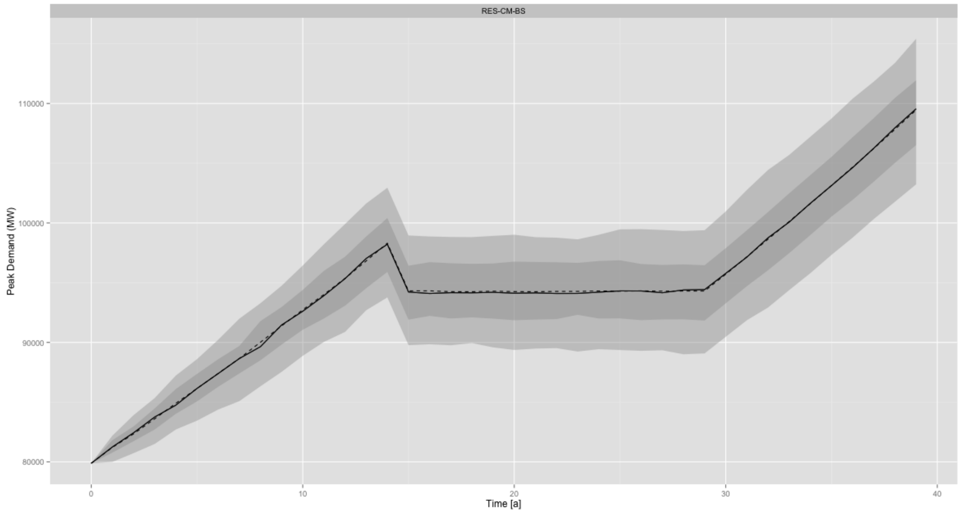

Figure 4.21: Peak demand trend in scenarios with a demand shock

Figure 4.22 shows that the sudden drop in demand followed by zero growth leads to a long cycle that continues up to year 30. The initial drop in demand in year 15 causes a sudden increase in the supply ratio. As demand growth does not rebound, a gradual dismantling of excess capacity over the next years is seen. An increase in the volatility of capacity prices (Figure 4.23) is observed. The high supply margin after the demand drop causes the capacity price to fall. This causes an overshoot in dismantling and consequently a spike in the capacity prices as the supply ratio goes below the administratively set lower margin. This reinforces the investment cycle. In this scenario, the high IRM protects consumers from shortages, despite the investment cycle. However, in a system with a lower IRM requirement, these swings threaten security of supply. Thus the optimal level of the IRM depends on the expected volatility of electricity demand growth: the higher the uncertainty, the higher an IRM is justified.

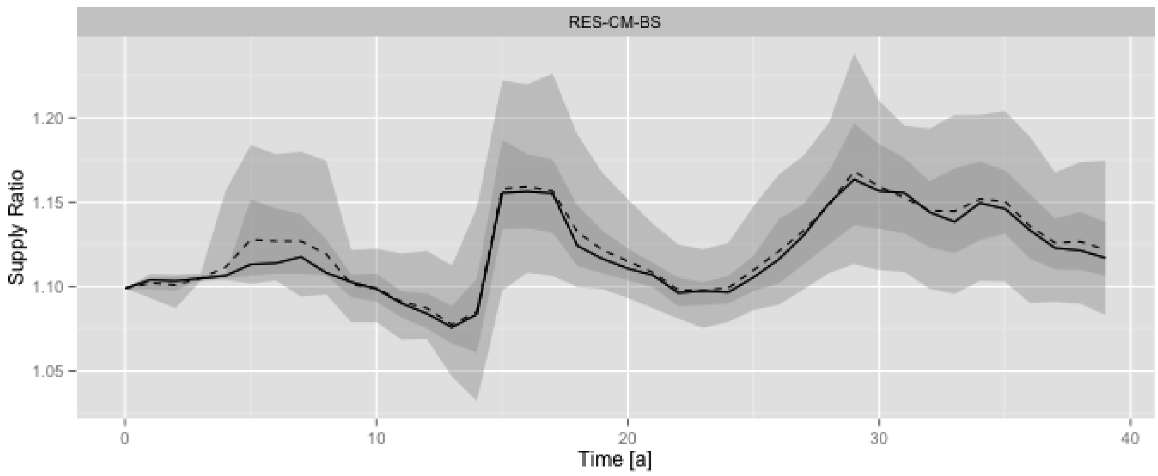

Figure 4.22: Supply ratio in a scenario with a demand shock

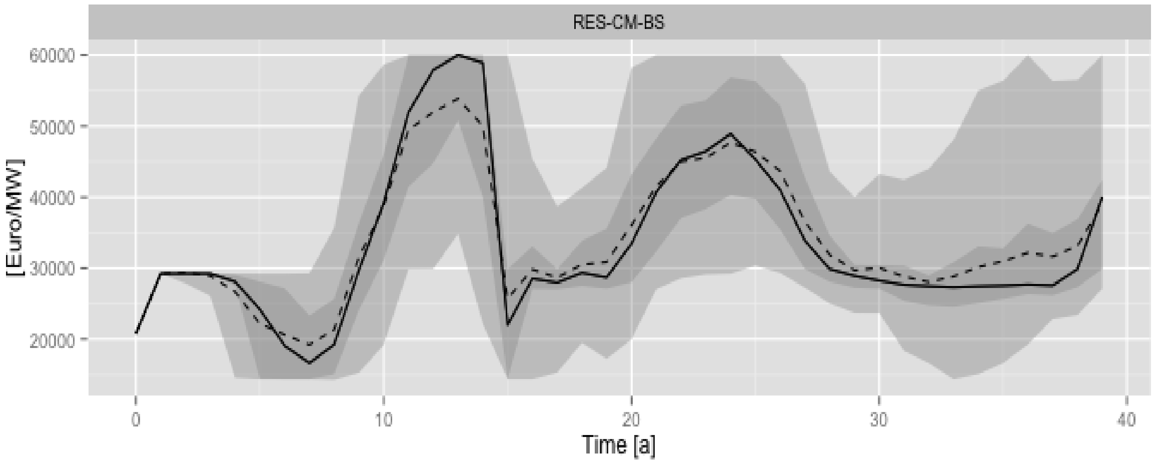

Figure 4.23: Capacity market clearing price in a scenario with a demand shock

4.5 Conclusions

A model of a capacity market in an isolated region with an ambitious renewable energy policy is presented. The capacity market provides a significant reduction in the number of shortage hours as compared to an energy-only market, also in the presence of a high share of renewable energy and a demand shock. In the latter case, investment cycles may develop, but if the reserve margin is high enough, security of supply is not strongly affected. In the presence of a growing share of renewable energy, a capacity market may reduce overall consumer costs as compared to a scenario without a capacity market. The capacity market mainly leads to more investment in low-cost peak generation units. It does not provide sufficient incentive for investment in nuclear power plants. Investment in nuclear power would require separate policy support, as is implemented in the UK. In comparison to a strategic reserve, a capacity market provides a more stable supply ratio, especially in the presence of a growing share of variable renewable energy sources.

The net cost to consumers of a capacity market is sensitive to the growth rates of demand, but it is robust enough to provide an adequate reserve margin under different demand growth conditions. In a declining demand scenario, higher support from the capacity market is required to maintain a given supply ratio. The opposite is true in a high demand growth scenario.

A lower capacity market price cap reduces capacity market price uncertainty without affecting its ability to reach the target IRM, as long as the price cap is above the cost of new entry. Therefore a capacity market price cap close to the cost of new entry should provide the required adequacy while minimizing capacity market price uncertainty. Extending the upper (*UM*) and lower (*LM*) margins of the capacity market demand function also reduces capacity market price uncertainty.

5. Forward capacity market

This chapter is based on Bhagwat et al. (2016c) with minor modifications.

5.1 Introduction

The UK Climate Change Act 2008 (UK Parliament, 2008), along with the National Renewable energy action plan (DECC, 2010) set UK on a path towards decarbonizing its economy. As the share of renewables in the supply mix increases, there is a concern that thermal generation will not be able to recover its costs. In response, the UK has implemented a capacity market.

The UK capacity market was initially proposed as part of the Electricity Market Reforms policy (UK Parliament, 2013). After much deliberation, the design for the capacity market was finalized in 2014. The capacity market is administered based on the Electricity Capacity Regulations 2014 (DECC, 2014b) and the Capacity Market Rules (DECC, 2014a) presented to the parliament. The first capacity auction took place in December 2014.

The EU allows its member states to customize the type and design of their capacity mechanisms in accordance with their adequacy policy requirements. Therefore, different capacity mechanisms are either being discussed or have already been implemented in the EU member states (Bhagwat et al., 2016a, 2016d; BMWi, 2015; DECC, 2014a; OFGEM, 2015; RTE, 2014). The UK has implemented a forward capacity market (FCM) with long-term contracts from new capacity.

A forward market means that the capacity that clears the market in the current year needs to be available in a future reference year. Therefore any generation unit, either existing or under construction, that is expected to be available in the reference year can participate in the capacity market. In the UK capacity market design, new and refurbished capacity that clears the market is provided with long-term contracts.

In this research, an agent-based model is used to study the effectiveness of a forward capacity market (FCM) in a system with a growing share of renewable energy. The FCM based on UK capacity market design is implemented as an extension of the EMLab-Generation agent-based model (De Vries et al., 2013; Richstein et al., 2015a, 2015b, 2014a)[8]. The effectiveness of the capacity market under different demand growth scenarios and design considerations is also analyzed. As the presence of a capacity market may or may not incentivize growth in particular technologies in the supply mix, the impact of capacity markets on the share of different technologies in the supply mix is assessed.

In order to understand the impact of policy design on the effectiveness of the capacity market, the results of the FCM are also compared with the analysis of a yearly capacity market (YCM) in the same scenario (Bhagwat et al., 2016b). The YCM is based on the

[8] http://emlab.tudelft.nl/

NYISO-ICAP[9] market, which is relatively a simpler design as compared to a FCM. In this design the capacity market is conducted only for the forthcoming year. Therefore only operational capacity participates in the capacity market and no long-term contracts are awarded.

In Section 2, the forward capacity market and its implementation in EMLab-Generation is presented. This is followed by the description of the various scenarios and indicators used in this study in Section 3. The results are discussed in Section 4 and the key conclusions from this research are summarized in Section 5.

5.2 Forward Capacity Market

The design of the forward capacity market with long-term contracts is based on the recently implemented UK capacity market. In this section, the key design elements of the UK capacity market and its implementation in the EMLab-Generation model are described. A forward market means that the capacity that clears the market in the current year needs to be available in a future reference year, in this case four years from the current year. Therefore, any generation unit that is expected to be available in the reference year, whether existing or under construction, can participate in the capacity market. Moreover, in the UK capacity market design, new and refurbished capacity that clears the market is provided with a long-term contract. A detailed description of all the rules of the capacity market is available in DECC (2014a).

On the supply side, the most significant element of the UK capacity market design is the heterogeneity of contract lengths. Power plants that clear the capacity auction and are new or less than four years from completion, are awarded 15-year contracts. Existing power plants that clear the four-year ahead capacity market are awarded a one-year contract. Plants that are being refurbished may obtain contracts of 3-year duration. Capacity that is awarded long-term contracts is ineligible for participation in the capacity market for the duration of the contract. Renewable energy capacity that receives renewable policy support is also ineligible to participate on the capacity market.

In the capacity market module of this model, the power producers submit price (in €/MW per year) - capacity (in MW) bids for each eligible power plant to the capacity market. The capacity component of a power plant's bid is determined by its capacity that is available during peak load. Existing and new power plants bid differently. A marginal cost-based approach is used for existing power plants. Per generation unit, the owner calculates the expected revenue from the electricity market. If the generation unit is expected to earn adequate revenues from the electricity market to cover its fixed operations and maintenance costs (in other words, its costs of staying online), the bid price is set to zero and the plant becomes a pure price taker. Units that are not expected to make adequate revenues from the energy market to cover their fixed costs of remaining online bid the difference between the fixed costs and the expected electricity market revenue, which is the minimum revenue that would be required to remain online. The bid price of plant that is new or under construction is

[9] NYISO-ICAP: New York Independent System Operator – Installed Capacity

set at its fixed operating cost, which is the minimum revenue that such a power plant would require to remain online without earning any revenue from the wholesale electricity market.

Power plants that are have a long-term capacity contract do not participate in the capacity market for the duration of the contract. At the end of the long-term contract period, these power plants are allowed to participate in the capacity market as existing capacity that is eligible for one-year contracts.

On the demand side, a sloping demand curve is utilized (Cramton and Stoft, 2005; DECC, 2014b; Hobbs et al., 2007; NYISO, 2013 and Pfeifenberger et al., (2009). The regulator sets the values of the installed reserve margin (IRM), the capacity market price cap and the slope of the demand curve. The demand requirement is reduced based on two factors. The first is the volume of long-term capacity contracts and the second is the contribution of renewables to peak load.

A forward market means that the capacity that clears the market in the current year needs to be available in a future year. The absolute value of the demand requirement (D_r) in *MW* for the current auction is based on four variables: the installed reserve margin (r), the expected peak demand (D_{peak}) for the forward year, which is forecasted by extrapolating past peak demand values, the total capacity that already has long-term capacity contracts (C_{LT}) and the total peak available capacity of renewable generation with renewable energy policy support (C_{RES}). The following equation describes the calculation of the demand requirement value:

$$D_r = \left(D_{peak} - C_{LT} - C_{RES}\right) \times (1 + r)$$

The demand target is calculated for the entire zone without considering locational and transmission constrains within a single zone.

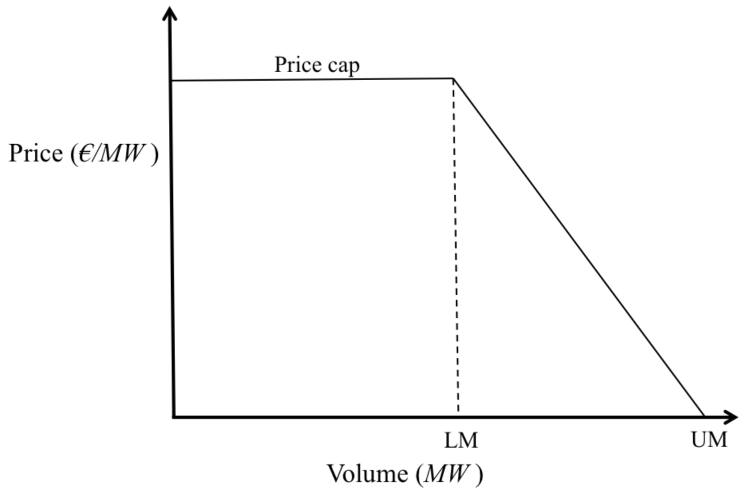

Figure 5.1: Illustration of a sloping demand curve

The demand curve is defined by two lines, first a horizontal section along the price cap (P_{CAP}) level, extending from the X-axis (0, P_{CAP}) up to the lower reserve margin point (LM, P_{CAP}). The remaining part is a downward sloping line from point (LM, P_{CAP}) to (UM, 0). See **Figure 4.1**. The upper (um) and lower (lm) reserve margins are defined by the user in percentage point and converted to absolute values in *MW* using the following equations.

$$UM = D_{peak} \times (1 + r + um)$$

$$LM = D_{peak} \times (1 + r - lm)$$

The capacity market clearing algorithm is modeled as a uniform price auction. The bids submitted by the power producers are sorted in ascending order by price and cleared against the sloping demand curve.

In this model, two types of contracts are offered to power plants that clear the capacity market to account for the heterogeneity of contract lengths. Existing capacity without a long-term contract is awarded a one-year contract. Capacity that is new or under construction and expected to be functional in or before the forward year is awarded a long-term contract at the auction clearing price. The forward period is four years and the long-term contract length is chosen to be 15 years, like in the UK. Since plant refurbishment is not modelled, this contract option is not considered in this model.

After the market is cleared, existing units that clear the capacity market (receive a one-year contract) are paid the current capacity market-clearing price. Newly built or under-construction capacity that clears the market (is awarded a long-term contract) receives payments for the period of the long-term contract fixed at the current year's market-clearing price. All remaining power plants with long-term contracts are also remunerated based on their contract price.

5.3 Scenarios and indicators

All scenarios are run over a time horizon of 40 years, 120 times in a Monte Carlo fashion with identical initial conditions. The initial supply mix is roughly based on the Eurelectric (2012) data for the UK. The renewable energy growth trends in all the scenarios are modeled based on UK's national renewable action plan (Beurskens et al., 2011; DECC, 2010) up to year 2020 and thereafter they follow the 80% pathway of the European Climate foundation's Roadmap 2050 projections (European Climate Foundation, 2010). The load duration curve is based on the ENTSO-E hourly demand data for the year 2014 for UK.

The fuel prices and demand growth are uncertain. The uncertainty of these parameters is created using an triangular trend distribution. The natural gas and coal price trends are based on fuel projects of the UK Department of Energy and Climate Change (Department of Energy & Climate Change, 2012) and extrapolated beyond 2035. The price trends for biomass (based on Faaij (2006)) and uranium are modeled stochastically using a triangular distribution. The average annual demand growth is 1%.

An isolated electricity market without interconnection and with four similar generation companies is considered. The baseline scenario BL consists of an energy-only market (no capacity market). The scenario LTCC consists of an electricity market with a four-year forward capacity market implemented in the system. New and under construction capacity that clears the capacity market is awarded a 15-year long-term contract while existing capacity is awarded a one-year contract. The scenario STCC consists of an electricity market with a yearly capacity market in which the capacity market is cleared for the coming year. In both the LTCC and STCC scenarios, the capacity market price cap is set at 95 k€/MW. This value is based on the price cap used in the UK capacity market. The lower and upper margins of the sloping demand curve are set at 3.5%. The installed reserve margin (IRM) requirement is set at 10% of peak demand.

The following indicators are used for evaluating the performance of the capacity markets:

- The average electricity price (€/MWh): the average electricity price over an entire run.
- The number of shortage hours (hours/year): the average number of hours per year with scarcity prices, averaged over all years and all Monte Carlo "runs" of a scenario.
- The supply ratio (MW/MW): the ratio of available supply over peak demand.
- The average cost to consumers of the capacity market (€/MWh): the cost incurred by consumers for contracting the mandated capacity credits from the capacity market, divided by the total units (MWh) of electricity consumed.
- The total average cost to consumers[10] (€/MWh): the sum of the electricity price, the cost from the capacity market and cost of renewable policy (if applicable) per unit of electricity consumed.

5.4 Results and analysis

In this section, the model results are analyzed. Figure 5.2 presents an overview. The results are also presented in a numerical form in Table 5.1.

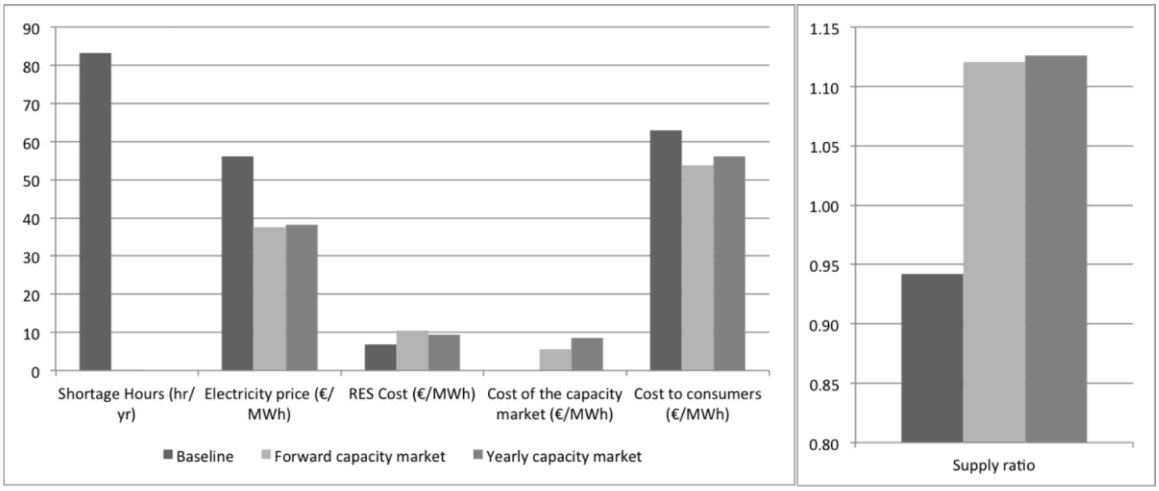

Figure 5.2: Performance overview of the three market designs

Table 5.1: Indicators for various scenarios

Scenario	Supply ratio	Shortage Hours (hr/yr)	Electricity price (€/MWh)	RES Cost (€/MWh)	Cost of the capacity market (€/MWh)	Cost to consumers (€/MWh)
BL	0.94	83.3	56.1	6.8	0	62.9
LTCC	1.12	0.0	37.6	10.4	5.6	53.7
STCC	1.13	0.0	38.1	9.5	8.6	56.1

[10] Note that this includes the cost of outages, because in this model the electricity price rises to the VOLL during shortages.

5.4.1 Performance of the forward capacity market

In this section, results from the scenario with a forward capacity market (LTCC) are compared with the baseline scenario (BL). The presence of a capacity market leads to an average supply ratio of 1.12 (a reserve margin of 12%). This value is two percentage points higher than the adequacy target of 10%, but it is within the 3.5 percentage point upper boundary. This overshoot can be attributed to the configuration (price cap and slope) of the demand curve used in this analysis. The capacity market clears at a level where it becomes economically viable for excess idle capacity above the targeted IRM to remain available. On an average, the forward capacity market clears at a price of 32,850 €/MW.

The implementation of a forward capacity market increases the reserve margin substantially and reduces most of the investment cycles that are seen in the baseline scenario, but a smaller and slower investment cycle is still present. See Figure 5.3. In this figure and the ones like it, the mean is indicated with a solid line, the average with a dashed line, the 50% confidence interval with a dark grey area and the 90% confidence interval with the lightly shaded area.

Early in the model runs, the power producers invest in new capacity because they expect sufficient returns from the capacity market. Due to its short construction time and low capital cost, OCGT is the preferred technology type for investment. (See Figure 5.4.) This new-built and/or under construction capacity clears the capacity market and is awarded long-term contracts, as it requires the lowest capacity price to remain online, even if it has little or no revenue from the electricity market. This capacity either operates during peak hours or remains idle altogether. The increase in capacity with long-term contracts leads to a reduction in the remaining capacity requirement (as the capacity requirement is reduced by the capacity having long-term contracts). However, these new 'peaker' plants are low in the merit order. Consequently, the existing supply function is extended with the new 'peaker' plants and the capacity market clearing prices are depressed, making investment in new capacity less attractive. The revenues of existing power plants that receive annual capacity contracts also decline, leading to dismantlement of power plants that do not receive adequate revenues. Because of the time delay in the market parties' responses, an investment cycle develops.

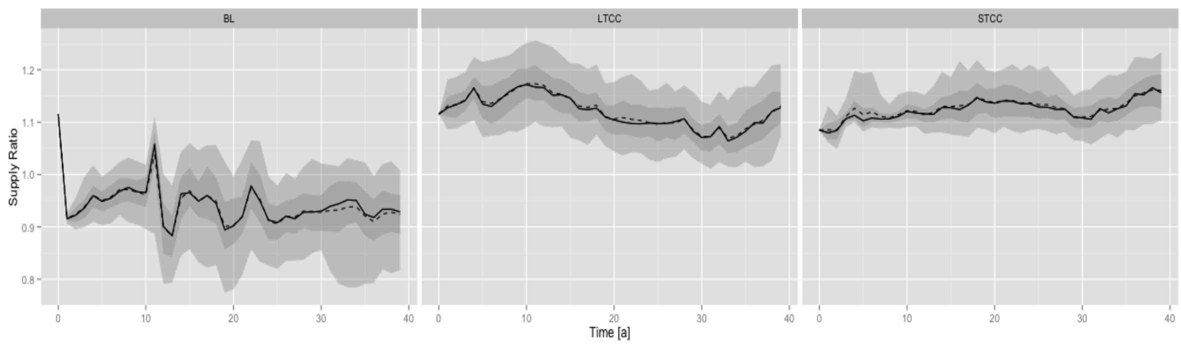

Figure 5.3: The supply ratio in scenarios without a capacity market (left), with a forward capacity market (center) and a yearly capacity market (right).

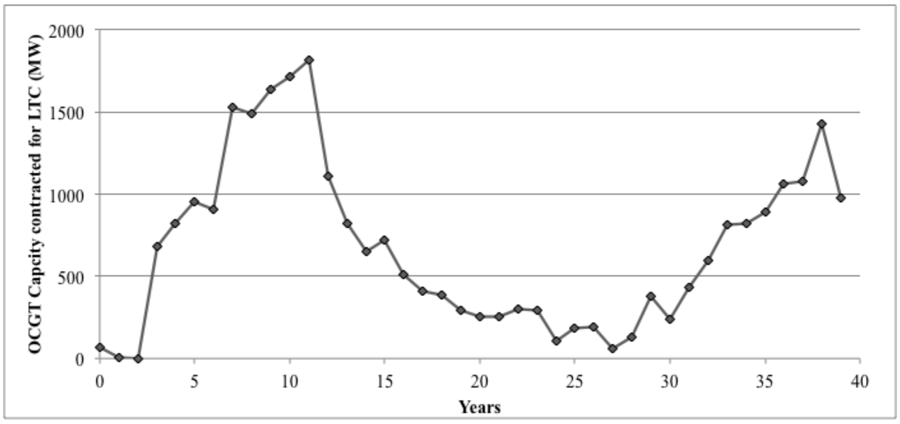

Figure 5.4: The average volume of OCGT capacity awarded with long-term contracts in the capacity auction

Because the IRM is set well above the real need for capacity, the capacity market stimulates power generators to invest in generation capacity that either remains idle or runs rarely. (This is partly a model artifact, as generator outages are not modelled.) Therefore, investment in OCGT technology with lowest capital cost becomes the preferred choice. The average volume of installed OCGT capacity increases from 6.1 GW in the baseline scenario to 14.7 GW in the forward capacity market (Figure 5.5). The presence of a forward capacity market does not affects the development of nuclear capacity in the system, because the remuneration from the capacity market does not add sufficient revenue for new nuclear power plants to recover their costs.

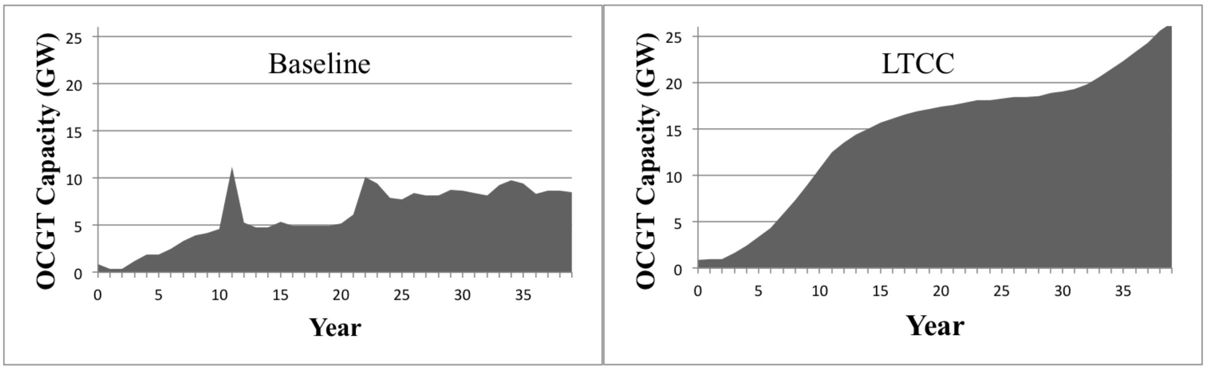

Figure 5.5: The average volume of installed capacity of OCGT in a scenario without (left) and with a forward capacity market (right).

In the presence of a forward capacity market, the high reserve margin causes the number of shortage hours to decline to almost nil. As a result, the average wholesale electricity price declines by 33% as compared to the baseline scenario. A significant reduction in price volatility is also observed due to the overcapacity (Figure 5.6). As is observed in Figure 5.2, the reduction in shortage hours leads to an increase in the cost of renewable energy subsidy. The cost to consumers of the capacity market is 5.7 €/MWh. However, the savings from reduction in shortage hours is large enough to compensate for these additional costs. In the presence of a forward capacity market, the overall cost to consumers declines by 15% on average as compared to the baseline scenario. It is observed that on average, the annual generation increases by 234 *GWh* in the scenario with a forward capacity market as compared to the baseline scenario, which leads to elimination of the shortage hours in scenario *LTCC*.

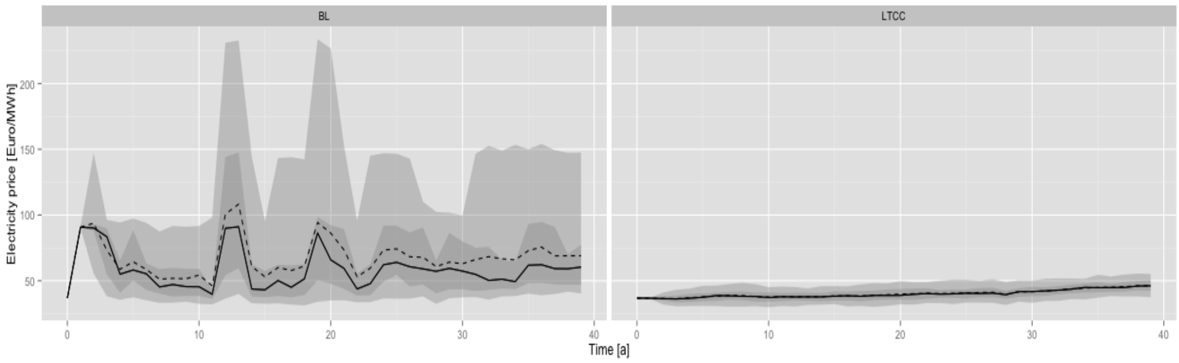

Figure 5.6: Electricity price in scenario without (left) and with (right) forward capacity market.

5.4.2 Comparison with the yearly capacity market

In this section, the forward capacity market (scenario *LTCC*) is compared with a yearly capacity market (scenario *STCC*). Both capacity market designs are able to provide the mandated installed reserve margins (*IRM*) levels. The average supply ratios in both scenarios are comparable (1.12 in LTCC and 1.125 in STCC). A similar reduction in shortage hours is observed in both scenarios (LTCC and STCC). The average electricity prices in both the scenarios are also comparable (prices in a scenario with a forward capacity market are marginally (1%) lower than that in the yearly capacity market). Figure 5.7 illustrates the difference between average electricity prices in the two scenarios. The maximum difference between the prices is less than 2 €/MWh.

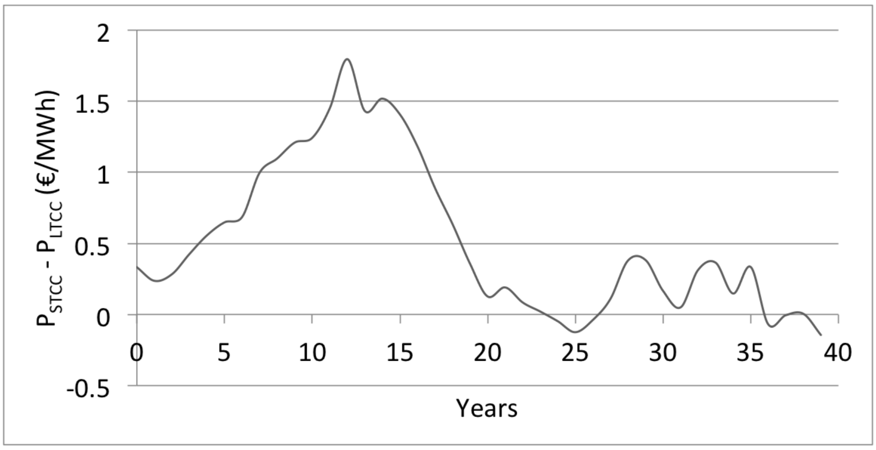

Figure 5.7: Average electricity price difference between scenarios with a yearly capacity market (STCC) and a forward capacity market (LTCC)

The capacity market prices in the yearly capacity market are more volatile than those in the forward capacity market (Figure 5.8). This can be attributed to the short-term nature of the yearly capacity market. Consequently, the average cost of the capacity market to the consumers is significantly higher in a scenario with a yearly capacity market (8.6 €/MWh**)** than with a forward capacity market (5.7 €/MWh**)**. This translates into a 4% higher total cost to consumers in the scenario with a yearly capacity market as compared to a scenario with a forward capacity market. The total cost to consumer in a scenario with a FCM is 53.7 €/MWh while in the one with a YCM is 56.1 €/MWh.

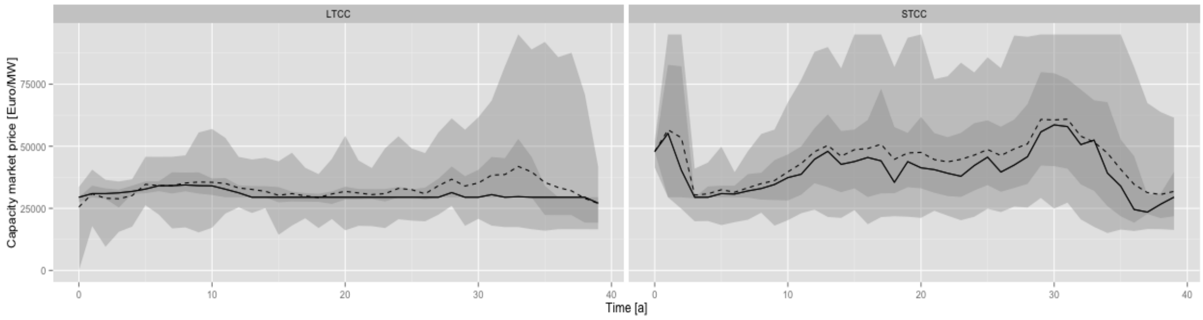

Figure 5.8: Capacity prices in scenario with a forward capacity market (left) and with a yearly capacity market (right).

5.4.3 The effectiveness of a forward capacity market in the event of a demand shock

While both capacity market designs perform well in scenarios with generally smooth demand growth, their ability in standing up to a sudden shock like the drop in electricity demand in Europe in the aftermath of the 2008 financial crises is also tested. This scenario is applied to both the short-term and the long-term capacity markets. The average demand growth trend (over all 120 Monte Carlo runs) is 1.5% for the first 14 years of the simulation. Then there is a sudden drop in demand. Subsequently, the average growth rate is zero for several years, after which it returns to 1.5% in the last 11 years of the simulation. The demand growth trajectory including the 50% and 90% confidence intervals is presented in Figure 5.9. The above described demand growth trajectory also was used in earlier research (Bhagwat et al., 2016b).

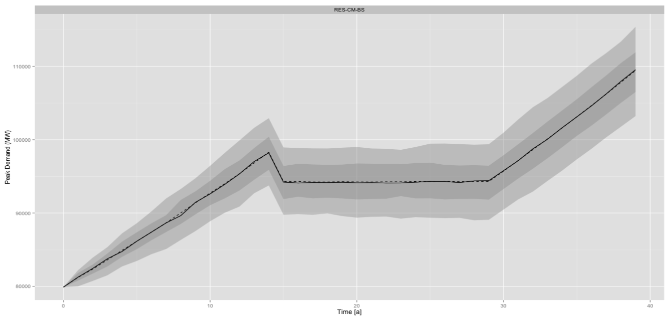

Figure 5.9: Peak demand trend in the demand shock scenarios

The drop in the demand leads to an investment cycle, both in a forward and an yearly capacity market. In case of a forward capacity market (FCM), the dip in demand leads to a spike in the supply ratio, which proceeds to decline gradually as the system adjusts to the zero growth level. The supply ratio stabilizes at the 10% IRM level. As demand growth picks up again, the capacity market price rises, which is followed by investment in new generation capacity. The total cost to consumers in a demand shock scenario with an FCM is 55.1 €/MWh.

In the case of an yearly capacity market (YCM), the capacity clearing price is more sensitive to the demand growth changes. The demand shock leads to overcapacity and a steep drop in the capacity price. As demand growth does not rebound, A gradual dismantling of unprofitable power plants over the next years is seen. When demand starts to grow again, this causes a price spike in the capacity market as the reserve margin is significantly diminished due to the dismantling. This reinforces the investment cycle. The total cost to consumers in a demand shock scenario with an YCM is 57.3 €/MWh.

As the capacity is traded year-ahead only, significantly higher price volatility is observed in the yearly capacity market than in the forward capacity market. As the decision regarding the decommissioning of power plants is based on their profitability, the price volatility provides these power plants with adequate revenues to break-even and remain in the system for a longer time, thus decommissioning of power plants is slower with a yearly capacity market as compared to a forward capacity market. This results in an overall higher reserve margin in a region with yearly capacity market during the period with no demand growth. See Figure 5.10 and Figure 5.11. When the results of both scenarios are compared, it is found that while both capacity markets experience an investment cycle but both continue to provide adequacy.

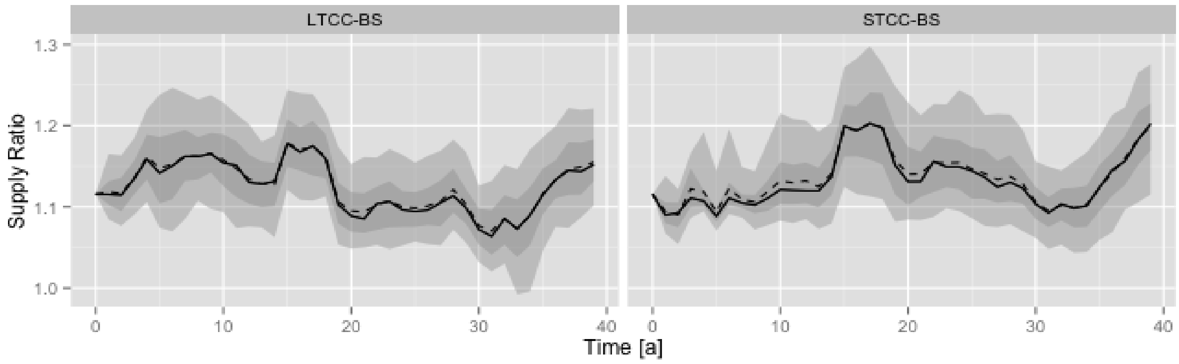

Figure 5.10: Supply ratio trend in a scenario with a forward capacity market (left) and a yearly capacity market (right)

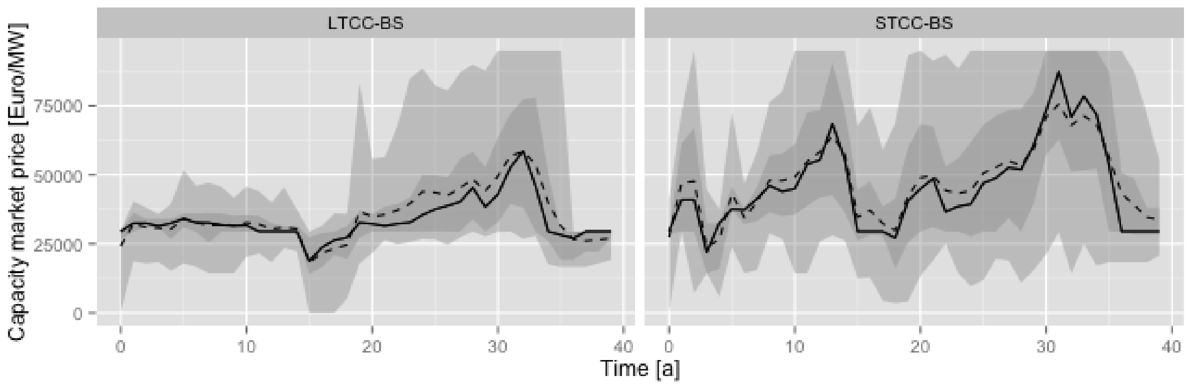

Figure 5.11: Capacity market prices in scenario with a forward capacity market (left) and a yearly capacity market (right)

5.4.4 Sensitivity analysis

In this section, the sensitivity of the forward capacity market (FCM) to different design parameters is studied. The variations to the design parameters used in this analysis are presented in Table 5.2.

Table 5.2: Scenario settings for the sensitivity analysis

<table>
<tr><th>Scenario</th><th>Capacity market cap (k€/MW)</th><th>Upper margin (%)</th><th>Lower margin (%)</th><th>Long-term contract length (years)</th></tr>
<tr><td>1</td><td>75</td><td rowspan="3">3.5</td><td rowspan="3">3.5</td><td rowspan="6">15</td></tr>
<tr><td>2</td><td>95</td></tr>
<tr><td>3</td><td>105</td></tr>
<tr><td>4</td><td rowspan="6">95</td><td>1.5</td><td>1.5</td></tr>
<tr><td>5</td><td>3.5</td><td>3.5</td></tr>
<tr><td>6</td><td>5.5</td><td>5.5</td></tr>
<tr><td>7</td><td rowspan="3">3.5</td><td rowspan="3">3.5</td><td>10</td></tr>
<tr><td>8</td><td>15</td></tr>
<tr><td>9</td><td>20</td></tr>
</table>

5.4.4.1 The capacity market price cap

The model is run with capacity market price cap values between 75 k€/MW and 115 k€/MW in increments of 20 k€/MW. See Table 5.2, Scenarios 1 – 3. All other parameters in the scenarios are same as in the LTCC scenario. The forward capacity market design does not exhibit a strong sensitivity to change in the value of capacity market price cap in terms of costs or supply ratios. The differences in the average cost to consumers and average supply ratio values are negligible.

Considering the development of the capacity clearing price trends over the entire simulation run, it is observed that a lower capacity market price cap leads to a reduction in the uncertainty of capacity market clearing prices. This can be observed from the standard deviation values presented in Figure 5.12. An increase in the price cap would effectively make the slope of the capacity market demand curve steeper, making the capacity price more volatile. This result conforms to the theory that a vertical or steep demand curve leads to more volatile prices (Hobbs et al., 2007).

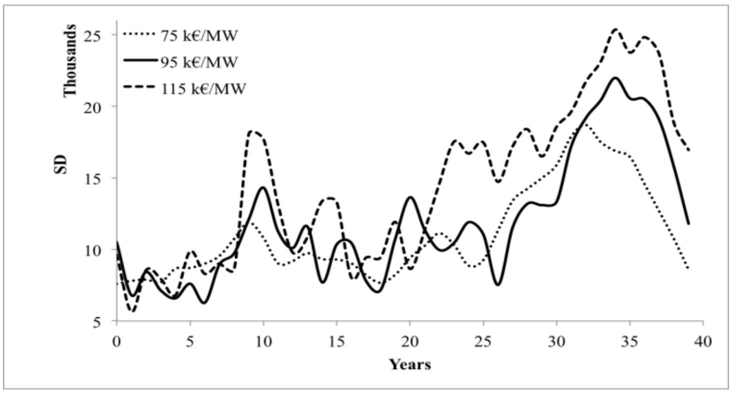

Figure 5.12: Standard deviation of forward capacity market prices in scenarios with different price caps

5.4.4.2 The slope of the demand curve

The forward capacity market is tested in three different slope configurations by varying the upper and lower margins. See Table 5.2: Scenarios 4-6.

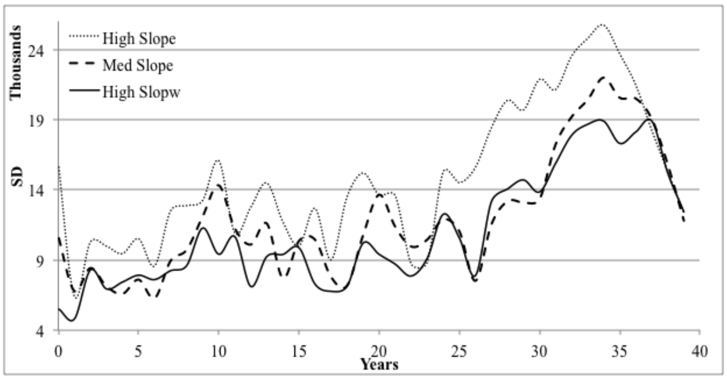

Figure 5.13: Standard deviation of forward capacity market prices in scenarios with different demand slopes

The forward capacity market does not exhibit any significant sensitivity to changes in slope of the in terms of change in costs and supply ratio. A steeper demand curve causes the capacity market prices to be more volatile (Figure 5.13). This indicates that a sloping demand curve is effective in reducing price uncertainty in the capacity market. As mentioned above, this observation concurs with theoretically expected results.

5.4.4.3 Contract duration

The contract length is varied from 10 to 20 years in steps of 5 years. See Table 5.2: Scenarios 7 – 9. As explained in Section 5.4.1, the generation capacity that obtains long-term contracts is mostly OCGT, as it has the lowest cost of remaining online, even with little or no revenue from the electricity market. This leads to reduction of the capacity requirement in the FCM and consequently to lower capacity clearing prices. Longer contract duration leads to longer periods with lower capacity market prices. This translates into a lower average capacity market clearing price and a reduction in the price uncertainty on the capacity market. See Figure 5.14.

However, it does not lead to a reduction in the overall cost to consumer from the capacity market. The cost savings from to the lower capacity market price are not very large, while the longer contract duration entails remunerating this capacity for a longer period, which adds to the cost to consumers. Therefore, on an average, the overall cost to consumer from the capacity market is not affected significantly by the duration of the long-term contracts.

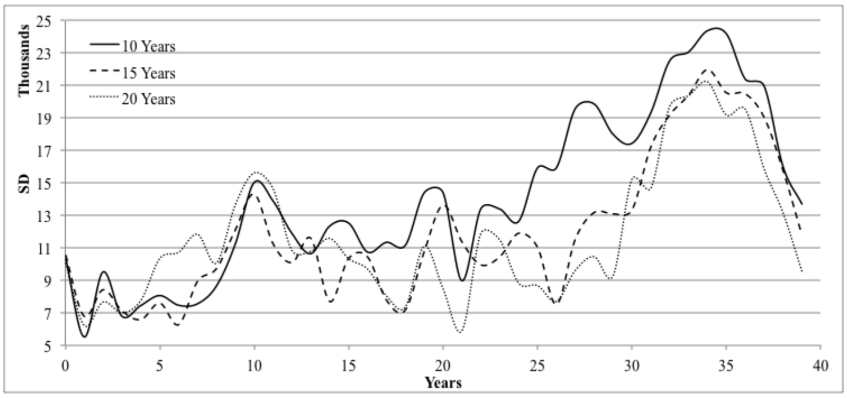

Figure 5.14: Standard deviation of capacity market prices in scenarios with differing long term contract periods

5.5 Conclusions

A model of a forward capacity market with long-term contracts that is based on the UK capacity market design in a system with a growing share of renewable energy is presented. This forward capacity market is compared with an yearly capacity market that is based on the NYISO-ICAP design.

Both capacity market designs are effective in reaching their adequacy targets. Because the forward capacity market responds a little slower to changes, the demand shock led to a lower reserve margin in the forward capacity market than in the yearly capacity market.

Implementation of a forward capacity market leads to a substantial reduction in the overall cost to consumers as compared to a baseline energy-only market, given the scenarios and the myopic investment behavior of the agents in this model. The reason is that the capacity price in a forward capacity market is less volatile and slightly lower on average than in a yearly capacity market. Like the yearly capacity market, the forward capacity market increases investment in low-cost peak generation capacity as compared to an energy-only market.

In a forward capacity market, reducing the capacity market price cap leads to a reduction in capacity price uncertainty. Similarly, a gentler demand slope (larger upper and lower margins) reduces capacity price uncertainty. The performance of the market does not change significantly if the contract duration is extended beyond ten years.

6. Cross-border effects of capacity mechanisms

This chapter is based on Bhagwat et al. (2016e) with minor modifications.

6.1 Introduction

This chapter analyses the cross-border effects of implementing various capacity mechanisms in an interconnected power system. The cross-policy effects due to implementation of dissimilar capacity mechanisms in two interconnected regions are also analyzed. The existing strategic reserve and capacity market model extensions that have already been implemented in EMLab-Generation are utilized.

In the EU the decision whether to implement a capacity mechanism and its design and implementation are left to the discretion of the member states. The UK has recently implemented a capacity market (DECC, 2014a) while France will do so in the near future (RTE, 2014). Belgium, Sweden and Finland make use of strategic reserves. Germany may implement a capacity reserve but decided against a full scale capacity market for the near future (BMWi, 2015).

In a highly interconnected system such as the continental European electricity system, there appears to be a risk that the uncoordinated implementation of capacity mechanisms reduces economic efficiency and may even negatively affect the security of supply in neighboring systems (Pérez-Arriaga, 2001; Elberg, 2014; Tennbakk, 2014; Finon, 2015; Gore, 2015; Mastropietro et al., 2015; Meyer and Gore, 2015; Bhagwat et al., 2016a).

In the next section the scenarios used in this analysis are described. This followed by the presentation of the results in section 3 and the conclusions in section 4. The EMLab-Generation model and the capacity mechanism extensions have been explained in detail in previous chapters (See Chapter 2, 3 and 4). Hence the model description has been left out of this chapter in order to avoid repetitions.

6.2 Scenarios

The EMLab-Generation model is run in a configuration consisting of two interconnected regions. Both markets have four power producers with identical initial power plant portfolios. The shares of generation technologies in the initial supply mix are based on the portfolio of thermal generation technologies in Germany (based on Eurelectric (2012) data; see also in the Appendix C). Power plant attributes such as capital costs, O&M costs and fuel efficiencies are based on the IEA World Energy Outlook 2011, New Policies Scenario (IEA, 2011). Technology development is simulated as a gradual improvement of these attributes, such as decreasing costs and improving efficiency rates. The assumptions regarding the power generation technologies are presented in Chapter 2.

The load-duration function is derived from 2010 ENTSO-E data for Germany (ENTSO-E, 2010). A triangular trend probability distribution function is utilized to generate stochastically varying fuel price and demand growth time series (see Appendix A). The coal and gas prices are based on scenarios of the UK Department of Energy & Climate Change (2012). The biomass prices are based on Faaij (2006) and those of lignite on Konstantin (2009). The development of renewable energy resources is based on the national renewable energy action plan for Germany (NREAP, 2010) up to 2020 and interpolated further.

For cases in which supply does not meet demand there is an electricity market price cap at 2000 *€/MWh*, which is assumed as the value of lost load (VOLL). In this modeling study, the value of lost load (VOLL) was chosen at the relatively low level. This is done in order to take into consideration demand flexibility that might occur during periods of high prices and also the segmented nature of the load duration curve that makes the model sensitive to VOLL.

As a reference scenario, the model is run in an "energy-only" mode, with no capacity mechanisms. Three scenarios with capacity mechanism are implemented; see Table 6.1. In the first scenario *(SR-EO)*, a strategic reserve is implemented in one zone while the other zone maintains an energy-only market. In the second case *(CM-EO)*, a capacity market is implemented in one zone while the interconnected zone maintains an energy-only market. In the third case *(CM-SR)*, a capacity market is implemented in one zone, while a strategic reserve is implemented in the interconnected zone. In these scenarios, there are no cross-border trade restrictions and imports are ineligible for capacity market contracts.

The reserve volume of the strategic reserve is set at 10% of peak demand and the reserve price is 800 *€/MW*. The dimensions of the capacity market are roughly based on the requirements of the NYISO-ICAP, the capacity market price cap is set at a 60000 *€/MW*. The IRM value is set at 10% of peak demand.

Table 6.1: List of scenarios

Scenario	Zone A	Zone B
BL	Energy-only	Energy-only
SR-EO	Strategic Reserve	Energy-only
CM-EO	Capacity Market	Energy-only
CM-SR	Capacity Market	Strategic Reserve

6.3 Results and analysis

6.3.1 Indicators

The following indicators are used in the analysis of the model results:

- The average electricity price (€/MWh): the average electricity price over an entire run.
- Shortage hours (hours/year): the number of hours per year with scarcity prices, averaged over the entire run.
- The supply ratio *(MW/MW)*: the ratio of available supply over peak demand.

- The cost of the capacity mechanism (€/MWh): the cost incurred by the consumers for contracting the mandated capacity credits from the capacity market or for contracting generating units into the strategic reserve.
- The cost to consumers (€/MWh)[11]: the sum of the electricity price, the cost of the capacity market and the cost of renewable policy (if applicable) per unit of electricity consumed, averaged over the entire run.

The percentage change in the values of indicators in both zones for the SR-EO, CM-EO and CM-SR scenarios, as compared to the baseline scenario (*BL*), are presented in Figure 6.1. The results are also presented numerically in Table 6.2. The average values presented in the results are calculated as annual values based on values from the 120 simulation runs over the 40-year time horizon. For the supply ratios and electricity prices over time, the median and mean trend along with the 50% and 90% confidence intervals (CI) are shown.

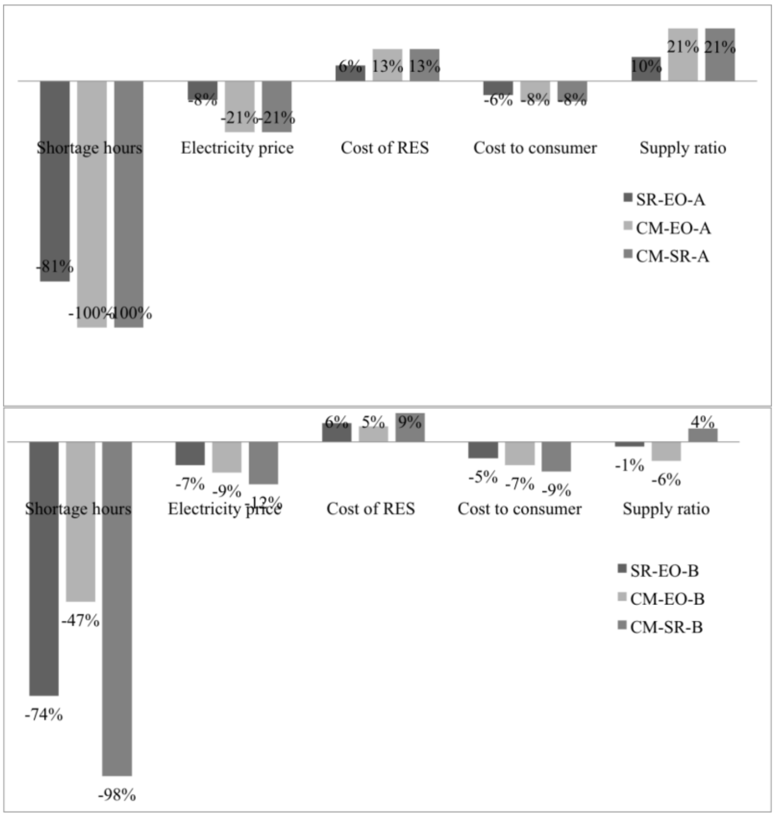

Figure 6.1: The percentage change in values of various indicators in Zone A (top) and Zone B (bottom) on implementation of capacity mechanisms as compared to the baseline scenario

Table 6.2: Annual average values of key indicators all scenarios

Scenario Name	Shortage hours (h/y)	Supply ratio	Electricity price (€/MWh)	Cost of RES (€/MWh)	CCCM (€/MWh)	Cost to consumers (€/MWh)
BL-A	58.4	0.93	58.1	11.5	0.0	69.6
BL-B	58.4	0.93	58.1	11.5	0.0	69.6

[11] Note that this includes the cost of outages, because in this model the electricity price rises to the VOLL during shortages.

CM-EO-A	0.0	1.12	46.1	13.0	4.8	63.9
CM-EO-B	31.0	0.87	52.8	12.1	0.0	64.9
SR-EO-A	11.0	1.02	53.7	12.3	-0.3	65.7
SR-EO-B	15.0	0.91	54.1	12.2	0.0	66.3
CM-SR-A	0.0	1.12	46.0	13.0	4.9	63.9
CM-SR-B	1.2	0.96	50.8	12.5	0.2	63.6

6.3.2 Cross-border effects of a strategic reserve

In this scenario, a strategic reserve is implemented in Zone A, while the interconnected zone (B) has an energy-only market. The outcomes from this scenario are compared with the baseline case (BL) in which both zones have energy-only markets.

The zone that implements a strategic reserve sees its supply ratio rise to 1.02, as observed in Figure 6.2, an increase of 9% compared to the baseline scenario. The shortage hours decline from 58.4 hours per year to 11 hours per year in this zone. As expected, the extreme price spikes in the baseline scenario are replaced by more frequent, but lower price spikes in the electricity market (see Figure 6.3). The average electricity price drops by 8%, from 58.1 €/MWh in the baseline to 53.7 €/MWh, which is due to the reduction in shortage hours. The strategic reserve operator is almost able to recover the cost of contracting the strategic reserve, which is indicated by the capacity mechanism cost to the consumers of -0.3 €/MWh. The operator earns revenues when the strategic reserve is dispatched in the zone where it is implemented and also from exports of the reserve capacity during hours that are consequent to the peak load hours. An overall decrease of 6% in the cost to consumers is observed.

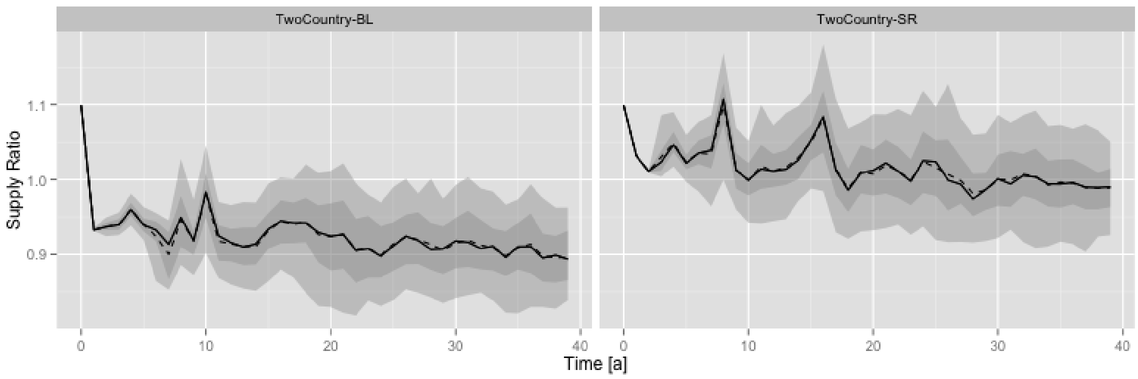

Figure 6.2: Comparison of supply ratio in Zone A without (left) and with a strategic reserve implemented.

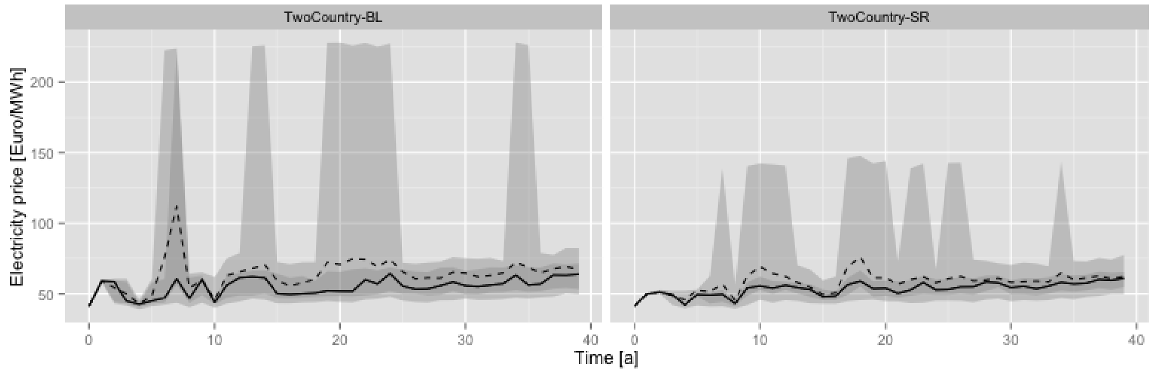

Figure 6.3: Comparison of electricity price in Zone A without (left) and with a strategic reserve implemented.

The supply ratio in the interconnected zone (Zone B) that has an energy-only market is 0.93, which is marginally lower than in the baseline scenario (Figure 6.4). However, the number of shortage hours in this zone is reduced by 74% from 58.4 h/yr to 15 h/yr, due to import of power from the neighboring zone during shortage situations. This leads to fewer price spikes in this zone and a reduction of the electricity price from 58.1 €/MWh to 54.1 €/MWh. An overall improvement in consumer benefit is observed, with the cost to consumers reduced by 5%.

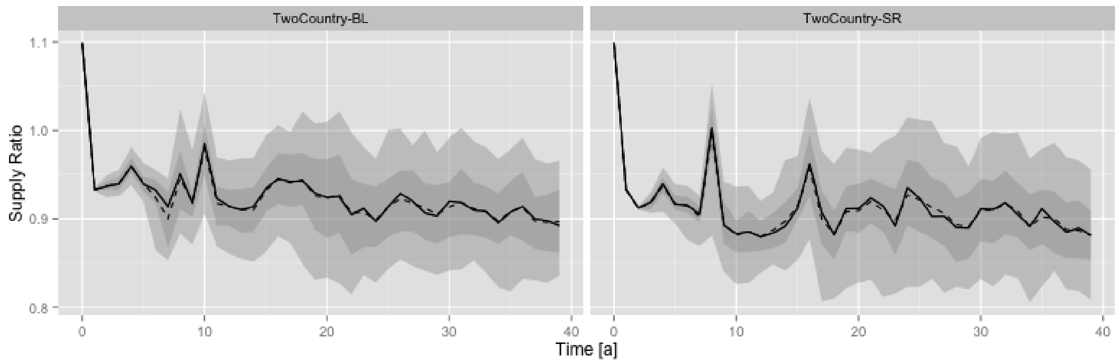

Figure 6.4: Comparison of the supply ratio in Zone B without (left) and with a strategic reserve (right) implemented in the neighboring interconnected Zone A

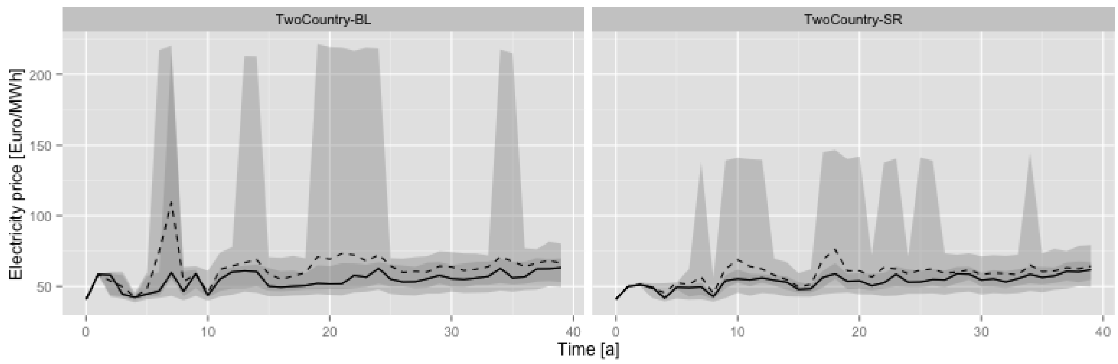

Figure 6.5: Comparison of electricity price in Zone B without (left) and with a strategic reserve (right) implemented in the neighboring interconnected Zone A

These results are compared to an isolated system with a similarly sized strategic reserve. The supply ratio is the same with and without an interconnector because the agents do not consider the interconnector explicitly in their investment decision. However, in the presence of an interconnector, part of the capacity from the zone with a strategic reserve is exported to the neighboring market, as there is no restriction on exports. Consequently, there are more shortage hours in the zone with the strategic reserve than in the isolated case, while the shortage hours in the neighboring energy-only region are reduced. This spillover leads to 2% increase in the net cost to consumers in Zone A, which increases from 64.4 €/MWh in an isolated system to 65.7 €/MWh in the scenario with an interconnector (SR-EO Zone A).

To summarize, implementation of a strategic reserve in one zone of an interconnected system improves the security of supply and net consumer benefit in that zone. The benefits spill over to the neighboring interconnected zone, both in terms of reduction in shortage hours and reduction in cost to consumers. In the other zone (with an energy-only market), no significant effect on investment is observed; however, this result may be caused by the fact that the investment decisions in the model did not consider imports.

6.3.3 Cross-border effects of a capacity market

In this scenario, a capacity market was implemented in Zone A, while the interconnected zone (B) has an energy-only market. The results from this scenario are compared with the baseline (*BL*) scenario in which both zones have energy-only markets.

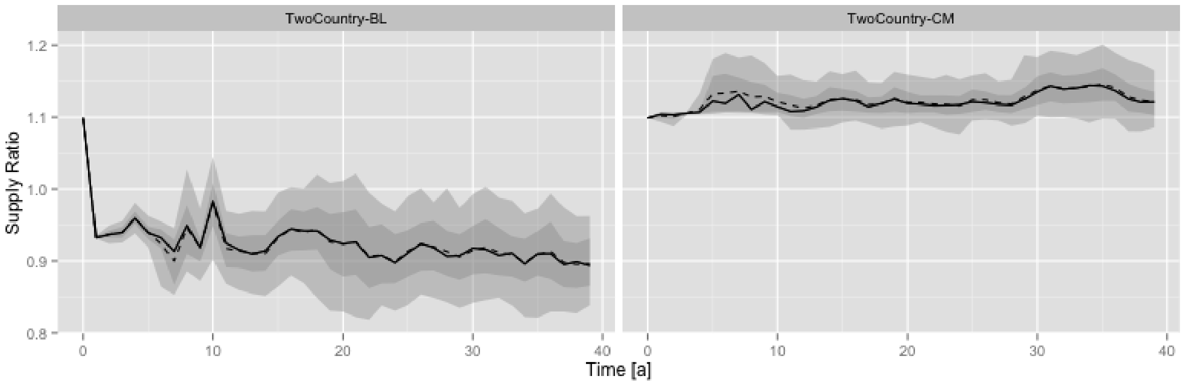

Figure 6.6: Comparison of supply ratio in Zone A without (left) and with a capacity market (right)

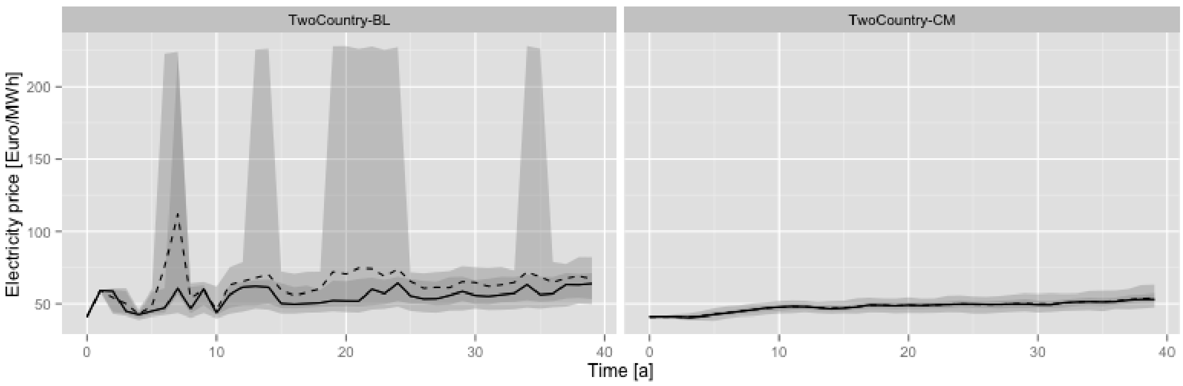

Figure 6.7: Comparison of electricity price in Zone A without (left) and with a capacity market (right)

In the zone with a capacity market (A), the average supply ratio is 1.12, which is 2.5-percentage point higher than the adequacy target. (See Figure 6.6.) The capacity market more than meets the adequacy goals in the presence of an interconnection. The apparent overshoot in capacity can be attributed to the configuration of the capacity market demand curve (slope and price cap) and also the segmented nature of the load duration curve. The high reserve capacity causes a steep reduction in shortage hours, from 58.4 hours per year to almost zero. The average electricity price drops by 20.7%, from 58.1 €/MWh in the baseline to 46.1 €/MWh. There is also a sharp decline in electricity price volatility in this zone, as can be seen in Figure 6.7. The capacity payments cost the consumer an additional 4.8 €/MWh. However, the gains from reduction in shortage hours offset the cost of the capacity market: the total cost to consumers decreases by 8.2%, from 69.6 €/MWh to 63.9 €/MWh.

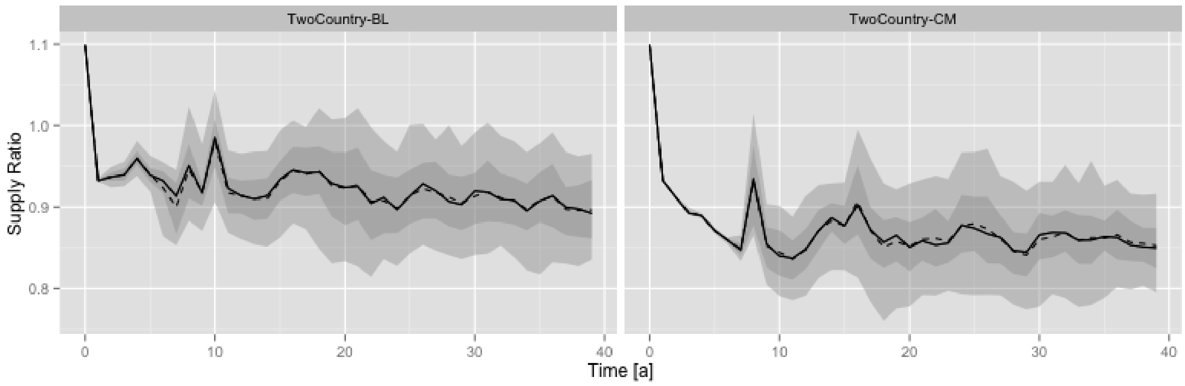

Figure 6.8: Comparison of the supply ratio in Zone B without (left) and with a capacity market (right) in the neighboring interconnected Zone A

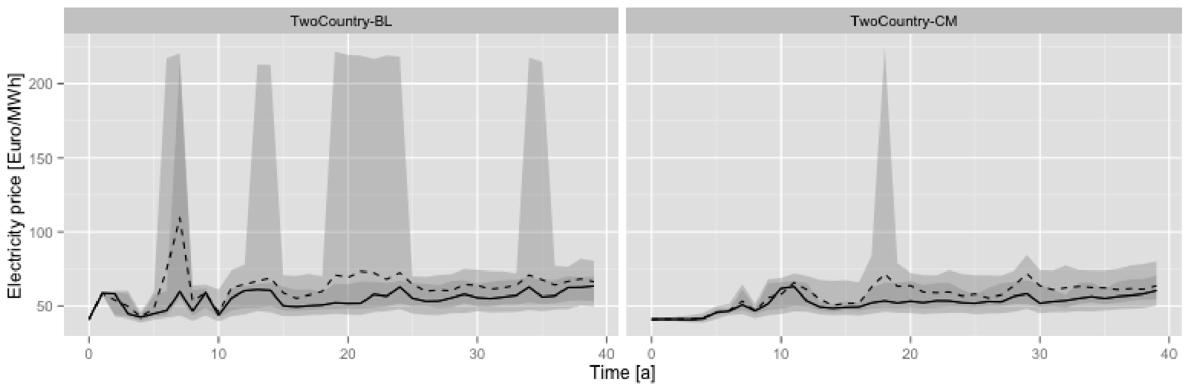

Figure 6.9: Comparison of average electricity prices in Zone B without (left) and with a capacity market (right) in the neighboring interconnected Zone A

On the other hand, a clear negative spillover effect in terms of adequacy is observed in the interconnected zone with an energy-only market (Zone B), where the supply ratio declines by 5.6%, from 0.93 in the baseline scenario to 0.87 (Figure 6.8). Nevertheless, the import of electricity from the neighboring zone dampens electricity prices (Figure 6.9) and reduces the number of shortage hours by 46.8% from 58.4 h/yr to 31 h/yr. The average electricity price declines from 58.1 €/MWh to 52.8 €/MWh. The net cost to consumers declines by 6.8% from 69.6 €/MWh to 64.9 €/MWh.

Figure 6.9 shows that there is some risk of an investment cycle in Zone B (the energy-only market), also in the presence of a capacity market in Zone A. The generators in Zone B are crowded out to the extent that even the additional capacity due to the capacity market in A may not be able to cover all the demand in the neighboring zone. In such situations, periods with substantial shortage hours in the energy-only market are observed (See Figure 6.10). Thus, despite the higher supply ratio in Zone A of the CM-EO scenario, the average reduction of shortage hours in Zone B is lower in this scenario than in scenario SR-EO.

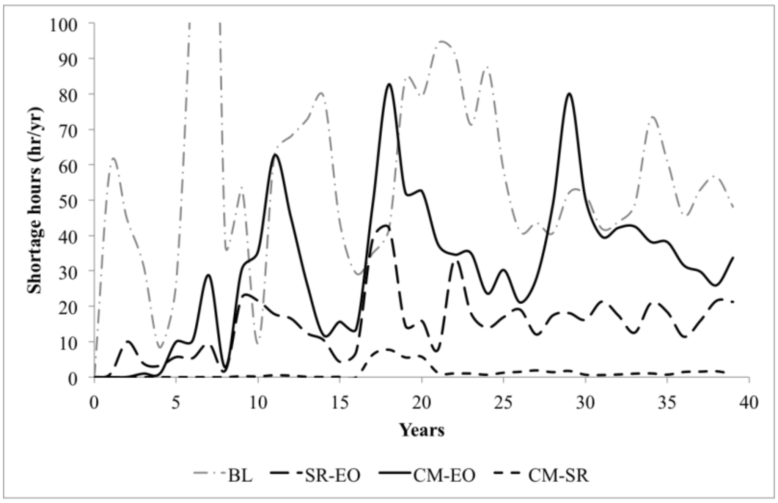

Figure 6.10: Average shortage hours in the energy-only market zone (Zone B).

The results for Zone A are compared with the case of a capacity market in a similar but isolated system. The average electricity price in the presence of an interconnector is 5.2% higher than in an isolated system, but the cost of the capacity market is 16.4% lower in the presence of an interconnector. This can be attributed to lower bids in the capacity market due to the additional income for generators from exports. On average, the capacity market clearing price observed in an isolated scenario is *31,558 €/MW* as compared to *27,017* €/MW in the CM-EO scenario. On the whole, the net cost to consumers in Zone A increases by 1.2% in the presence of an interconnector. This is the cost of free riding by consumers in the neighboring region. Note that this cost is a function of the relative sizes of the two interconnected systems and of the size of the interconnector.

To summarize, the capacity market achieves the adequacy goals in the zone that implements it, even in the presence of interconnections. The supply margin remains adequate and due to the low number of shortage hours, the total cost to consumers is reduced. The connected energy-only zone free rides on the security of supply provided by the capacity market. The free riding leads to a marginal increase in the cost to consumers of the region implementing a capacity market, but the overall consumer benefit improves. However, a capacity market suppresses investment in the interconnected zone, which may make the neighboring zone import dependent and can lead to an investment cycle there.

6.3.4 Cross-policy effects due to implementation of dissimilar capacity mechanisms

In this scenario (CM-SR), a capacity market is implemented in one zone (Zone A) while the interconnected zone (Zone B) implements a strategic reserve. The cross-border effects that may arise from the implementation of dissimilar capacity mechanisms in interconnected zones are analyzed. The results from scenario CM-SR are compared with those from scenario CM-EO and SR-EO. This allows us to analyze the impact that capacity mechanisms have on each other's effectiveness when implemented in interconnected markets.

Based on the values of the various performance indicators presented in Figure 6.1, the implementation of dissimilar capacity mechanisms in the two zones leads to a reduction of shortages and of the cost to consumers in both zones. The performance of the capacity market is hardly affected by the presence of a strategic reserve in the neighboring zone. There is no significant change in the indicators of the zone that implements a capacity market (Zone A), without (CM-EO) or with (CM-SR) a strategic reserve in the neighboring interconnected zone (Zone B), as is observed in Figure 6.11 and Figure 6.12. These results not only indicate that the capacity market is a robust policy mechanism, but also that the strategic reserve in the neighboring zone does not impact the capacity market negatively. This is not surprising, as the strategic reserve was shown to have a positive spillover effect in the SR-EO case.

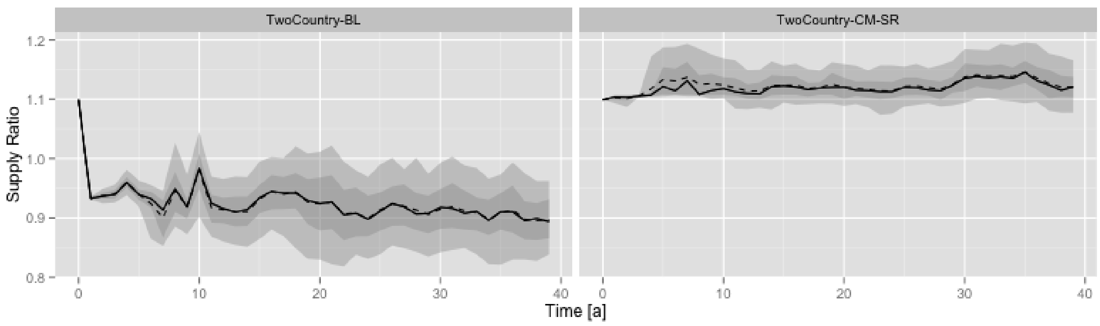

Figure 6.11: Supply ratio in the baseline (left) and in CM-SR scenario (right) in Zone A

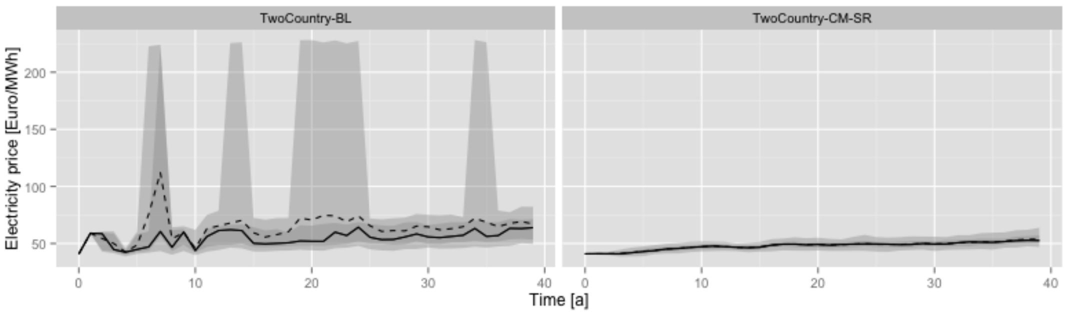

Figure 6.12: Electricity prices in the baseline (left) and in CM-SR scenario (right) in Zone A

In Zone B, with a strategic reserve, the import of electricity from A (with a capacity market), along with the additional capacity available due to the strategic reserve, leads to a strong reduction in shortages hours (by 98% as compared to SR-EO), a reduction of the price volatility and a 9% reduction in the average electricity prices (Figure 6.14). However, the exports from A to B reduce the need for the strategic reserve, as a result of which the strategic reserve no longer is able to recover its costs, which now are 0.2 €/MWh. Apparently, in this case a smaller strategic reserve would have sufficed.

The supply ratio in Zone B in scenario CM-SR (0.96) is lower than in the SR-EO scenario (1.02), a difference of 6 percentage points, as can be seen in Figure 6.13. This indicates that in the presence of the capacity market, the strategic reserve is less effective in maintaining a certain supply ratio. However, the strategic reserve reduces the risk of investment cycles, as is shown in Figure 6.10, and contributes to a low number of shortage hours.

With respect to the capacity market in Zone A, the difference in the capacity market clearing price is less than 1% in CM-SR *(27,231 €/MW)* as compared to CM-EO *(27,017 €/MW)*, which indicates that the presence of a strategic reserve in the interconnected zone does not impact capacity prices significantly. See Figure 6.15.

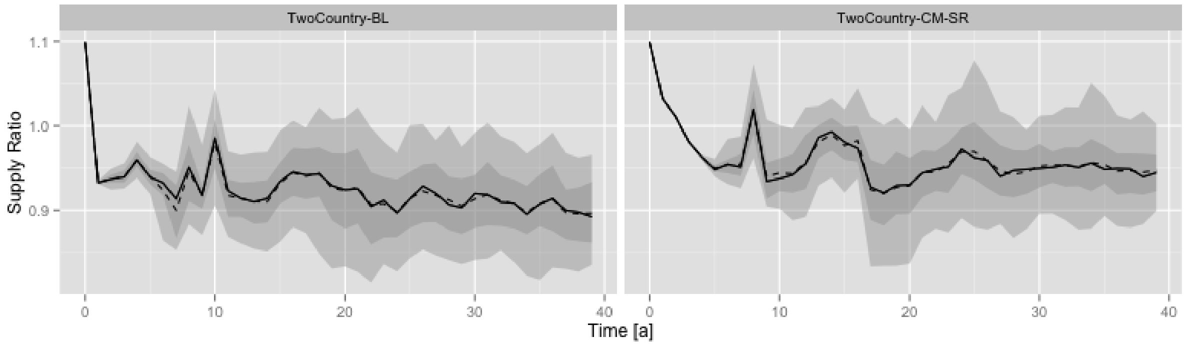

Figure 6.13: Supply ratio in the baseline scenario (left) and in scenario CM-SR (right) in Zone B

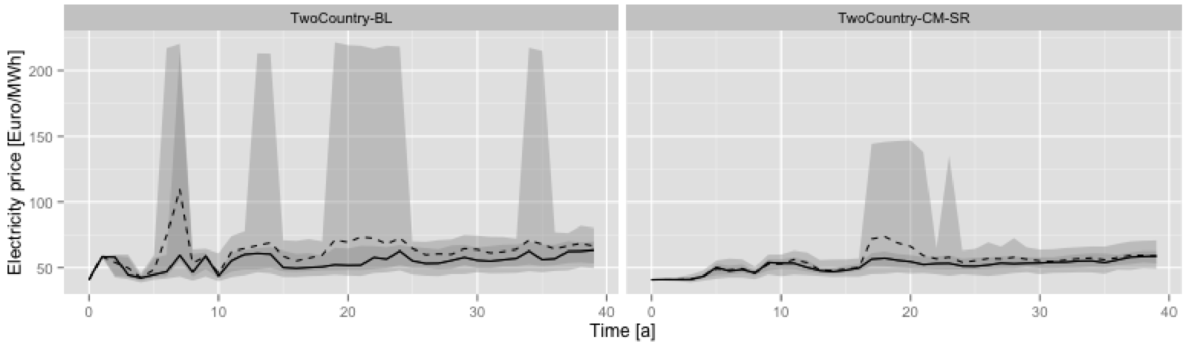

Figure 6.14: Electricity prices in the baseline scenario (left) and in scenario CM-SR (right) in Zone B

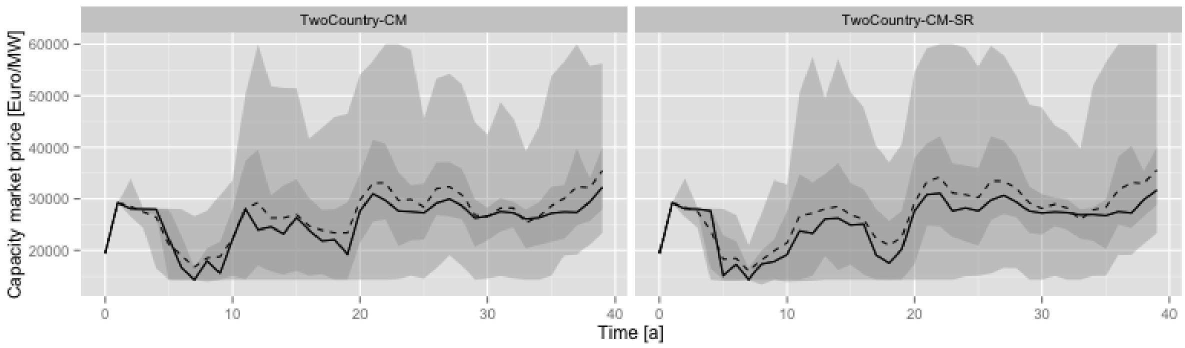

Figure 6.15: Capacity market clearing prices in scenario CM-EO (left) and CM-SR (right)

6.4 Conclusions

An analysis of the cross-border effects that may arise due to the implementation of capacity mechanisms in interconnected electricity markets with the use of an agent-based model are presented. A capacity market and a strategic reserve are analyzed. In this model, both capacity mechanisms improve the security of supply and contribute positively to consumer benefit in both zones.

In the model, interconnection with a neighboring zone does not affect the ability of a capacity market to reach its policy goals. The neighboring zone may experience a positive spillover and therefore free ride on the capacity market, but may also become import dependent. The free riding may cause an increase in cost to the consumers in the capacity market that are paying for the additional adequacy. The generators in the neighboring energy-only zone may be crowded out, in some cases to the extent that an investment cycle develops.

A strategic reserve also has a positive spillover effect on a neighboring energy-only market, both in terms of reduction in shortage hours and cost to consumers. However, the presence of an energy-only market in a neighboring zone has a negative effect on the performance of the strategic reserve with respect to the net cost to consumers and the number of shortage hours, when compared to an isolated system with a strategic reserve.

A capacity market reduces the need for, but may also reduce the effectiveness of a strategic reserve implemented in an interconnected zone. However, a strategic reserve can reduce the crowding-out effect that is caused by the capacity market on its electricity market and thus lower the risk of investment cycles.

7. Expert survey on capacity markets in the US: Lessons for the EU

This chapter is based on Bhagwat et al. (2016a) with minor modifications.

7.1 Introduction

As member states of the European Union are starting to implement capacity markets, learning from other regions with more experience could not only reduce the risk of policy failure but could also help improve the design and implementation of new market mechanisms. Wholesale electricity markets in the northeast United States have over a decade of experience in implementing and operating capacity markets. Over the years, the capacity market designs have been modified to address a number of issues that have arisen. A few examples of these issues are the role of demand response; whether locational constraints should be imposed, how far forward such markets should be run, and whether separate markets should be created for flexible capacity to back up intermittent renewables. The objective of this research is to draw lessons for Europe from the American experience.

Over the past decade, three wholesale electricity market regions in northeast United States implemented capacity markets (NYISO, ISO-NE, and PJM).[12] These markets have differing designs and have evolved over their periods of existence. This evolution includes the creation of separate markets for flexible capacity, the geographical definition of market sub-regions, and modifications to market clearing mechanisms (such as the use of demand curves). MISO has recently implemented a capacity market. Capacity markets have not been implemented in the southwest region (Southwest Power Pool or SPP). The state of California has imposed a resource adequacy requirement on load serving entities, but has not created a centrally coordinated market to facilitate efficient trading of resources to meet that requirement. California’s resource adequacy framework is described in the literature by Pfeifenberger et al. (2012), CPUC (2015), CAISO (2015)

After a desk review of the four capacity markets in the US, this chapter presents a survey of experts with knowledge of the United States electricity sector. The goal of this survey was to provide insight and advice to the EU with respect to selecting, designing, implementing and administering capacity markets in a highly interconnected electricity network, based on the experience with capacity markets in the United States. Emphasis was given to cross-border effects that may arise from implementing capacity mechanisms in interconnected regions. The survey respondents were questioned about such occurrences and their impact as well as how they were dealt with in the US experience. The respondents invited to participate in the survey represented various stakeholders (Details in Section 7.3).

[12] NYISO: New York - ISO, ISO-NE: ISO New England, PJM: Pennsylvania-New Jersey-Maryland.

This chapter is structured as follows. Section 2 provides a description of the four capacity markets in the United States followed in Section 3 by a description of the knowledgeable expert survey. The survey results and conclusions are presented in Section 4 and 5 respectively.

7.2 Capacity markets in the United States

The development of competitive wholesale electricity markets has been described in Borenstein and Bushnell, (2000); Brennan et al., (2002); Joskow, (2008b, 2006, 1997); Navigant Consulting, (2013); Sioshansi, (2013). Currently, the United States has seven regional wholesale electricity markets that are administered by independent system operators (ISOs)[13], namely SPP, ERCOT, MISO, CAISO, ISO-NE, NYISO, PJM (IRC, 2015). Capacity markets have been implemented in the four northeast-Midwest markets of NYISO, PJM, NE-ISO, and MISO[14]. Their performance has been discussed by, among others, Harvey (2005), Harvey et al. (2013), and Spees et al. (2013).

Each region has its own unique capacity market design (see Table 7.1) and modes of interconnection with neighboring regions. This makes the study of US capacity markets relevant for Europe. As the heterogeneity in US capacity markets provides the context for the survey findings, a brief overview of the different capacity market designs presently implemented in the United States is presented.

Table 7.1: Difference in design of various capacity markets in the US (Based on Spees et al., 2013**).**

Market	Forward Procurement Period	Auction Process	Procurement	Demand Curve
PJM	3 Years	Uniform price	Mandatory Auction, Bilateral	Sloped
NYISO	1 Year	Uniform price	Mandatory & Voluntary Auctions, Bilateral	Sloped
ISO-NE	3 Years	Descending clock	Mandatory Auction, Bilateral	Vertical
MISO	1 Year	Descending clock	Mandatory Auction, Bilateral	Vertical

7.2.1 NYISO: Installed Capacity Market

The New York Independent System Operator (NYISO) organizes an installed capacity (ICAP) market. Unforced capacity (UCAP) (NYISO, 2013a, 2013b) is offered in a series of auctions by generators. Load-serving entities are obligated to purchase the minimum volume of unforced capacity that has been assigned to them (Harvey, 2005; NYISO, 2013a, 2013b). UCAP is defined as the installed capacity adjusted for availability, as provided by the Generating Availability Data System (GADS) (NYISO, 2013b). Harvey (2005) describes how the UCAP is calculated. The unforced capacity requirement is calculated from the Installed Reserve Margin (IRM) and forecasted peak load (NYISO, 2013b). The IRM, defined as the required excess capacity (presented as percentage of expected peak demand), is established

[13] An illustration of the areas of the ISOs is available at www.ferc.gov/industries/electric/indus-act/rto.asp
[14] MISO: Midcontinent ISO.

such that the loss-of-load expectation (LOLE) is once in every ten years, or 0.1 day/year. The LOLE represents the probability that the supply would be lower than demand, expressed in time units. In NYISO, ‘days/year’ are used (Čepin, 2011)).

Mandatory spot auctions for capacity are conducted once a year for the coming year. In these auctions, supply-side bids of capacity are cleared against a sloping demand curve. The parameters of the sloping demand curve are reviewed every three years. The ISO contracts the required capacity from the capacity market on behalf of load serving entities (*LSEs*), the cost of which is recovered from the customers as an additional charge. NYISO has defined two six-month capability periods during which it tests the maximum generation output of parties that have sold capacity credits: a Summer capability period (May 1st - Oct 31st) and a Winter capability period (Nov 1st – April 30th) (NYISO, 2014). Market parties are allowed to correct their positions in capability-period auctions and again in monthly spot auctions. Imports are allowed to bid into the capacity market, provided that they adhere strictly to rules regarding transmission capability, electricity market bidding, and availability (NYISO, 2013b). Market parties are also allowed to conclude bilateral contracts. A detailed description of the market rules is available (NYISO, 2013b; Spees et al., 2013).

7.2.2 PJM: Reliability Pricing Model

The PJM ISO administers an area covering parts of thirteen states and the District of Columbia. The capacity market in this region is called the Reliability Pricing Model (RPM). RPM divides the region into Locational Deliverability Areas (LDAs) that reflect the demand and supply conditions in different locations.

The RPM is a three-year forward capacity market (Cramton and Stoft, 2006). In the first step, mandatory three-year forward base residual auctions (BRA) are conducted. The suppliers’ bids are cleared against a sloping demand curve known as the variable resource requirement (VRR). The shape of the VRR depends upon the cost of new entry (CONE) and the administratively set reliability requirement value (Bowring, 2013a, 2013b; Hobbs et al., 2007; PJM, 2013). The BRA is followed by incremental auctions (IA) that are conducted to allow market parties to adjust their positions if required.

The load serving entities (LSE) are also allowed to meet their reliability requirement via self-supply as well as bilateral contracts with generators. As in the NYISO-ICAP, imports are allowed to participate in capacity markets provided they comply with all PJM requirements (as approved by FERC). PJM has recently proposed capacity performance rules (PJM, 2014). Detailed description of the PJM-ICAP is available in (Bowring, 2013b; Hobbs et al., 2007; PJM, 2013; Spees et al., 2013).

7.2.3 ISO-NE: Forward Capacity Market

The New England ISO covers six states. The ISO-NE initially implemented an ICAP market in 1998. In 2002, deficiencies in the market design were identified by FERC. After much deliberation and negotiation, ISO-NE transitioned from ICAP to a Forward Capacity Market (FCM) in 2008 by conducting an auction for year 2010 (Benedettini, 2013; ISO New England Inc., 2015).

Similar to PJM-RPM, the ISO-NE FCM is a three-year forward market but with a vertical demand curve that has a price cap and floor. The resource adequacy requirement is calculated based on a LOLE of 0.1 day per year. The FCM employs a descending clock auction unlike other capacity market designs. Imports are allowed to participate in the FCM provided they comply with all FERC-approved requirements.

In the FCM, a three-year ahead forward capacity auction (FCA) is initially conducted followed by annual and monthly reconfiguration auctions in order to allow market parties to make adjustments. The design of the FCM is described in detail in Benedettini, (2013); ISO New England Inc., (2015), 2014a, 2014b; Spees et al., (2013). The market is presently undergoing a redesign process based on findings of the Strategic Planning initiative (ISO New England Inc., 2014c).

7.2.4 MISO: Planning Resource Auction

The Midcontinent ISO introduced the Planning Resource Auction (PRA) in 2013 to replace its Voluntary Capacity Auction (VCA). Two types of auctions are conducted. Initially, the PRA is a sealed-bid auction for the upcoming year in order to provide a clearing price for each of the local resource zones. Subsequent transitional auctions allow market participants to adjust their positions (MISO, 2013). The PRA is held two months prior to the beginning of the planning year.

The planning reserve margin is set by MISO to achieve a LOLE of 0.1 day per year. The MISO region is divided into Local Resource Zones (LRZ) to ensure sufficient capacity in each geographic zone. The PRA utilizes a vertical demand curve. One of the recommendations of the 2013 State of the Market Report is to implement a sloped demand curve similar to the PJM RPM system (Potomac Economics, 2014).

External resources are allowed to participate in the PRA provided that they meet MISO's FERC-approved requirements, including the must-offer obligation. Detailed description of the MISO PRA is available in MISO, (2015 and 2013); Potomac Economics, (2014); Spees et al., (2013).

7.3 Expert Survey

The main reason for undertaking a survey was to gain a multi-dimensional understanding of the performance of capacity markets in the United States. Considering developments in the EU, the survey is intended to provide insights that may assist the various stakeholders in the European Union with the design and operation of capacity markets.

A broad range of electricity sector experts was surveyed. The survey was conducted anonymously and the respondents included experts from the electricity industry, market operators, government/regulatory agencies, academia, and consulting firms (see Figure 7.1); respondents are weighted toward consultants and evenly divided among the rest. The survey was conducted between November 17, 2014 and November 30, 2014. The total number of participants that completed the survey was 22.

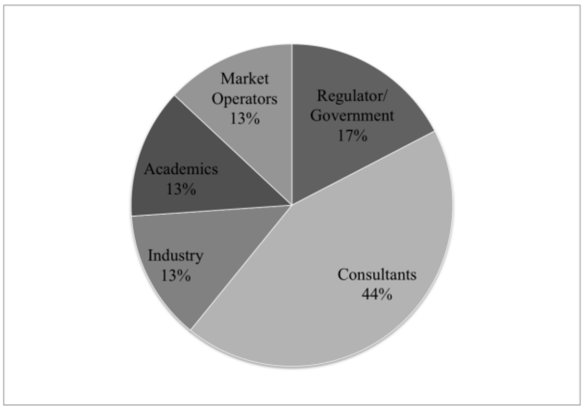

Figure 7.1: Share of participant's profession

The survey focused on the overall impact of capacity markets with an eye toward providing expert advice to the member states of the European Union. Participants were asked 15 open-ended questions in the form of an online questionnaire. The list of survey questions is provided in the Appendix D and the summary analysis of the results follows.

7.4 Results

In this section the results of the expert survey are presented. This section is divided into two parts: first, insights from the experience with capacity markets in the United States and second, advice to the member states of the European Union.

7.4.1 Insights from US capacity markets

In this section the responses of the experts on the impact of implementing capacity markets are summarized. The key areas of concern highlighted by the respondents are presented. This is followed by insights into the performance of capacity markets in terms of their effectiveness in achieving policy goals, impacts on consumers, and cross-border effects arising from interconnection with neighboring regions.

7.4.1.1 General Concerns

The respondents identified some issues of concern with regard to the capacity markets. These concerns are ordered according to the frequency of their mentions. The first issue, mentioned by 36% of the respondents, is the differing designs of neighboring capacity markets, including the mismatch in capacity auction time frames. For example, some capacity markets clear three years ahead while others one year ahead. This issue was also identified by Harvey et al. (2013). Second, the continuous changes in administrative rules in recent years have increased uncertainty and regulatory risk for investors (mentioned by 14%). The third issue (also mentioned by 14%) concerns the exercise of market power, including bidding above marginal cost and then “double dipping”. This is the practice of selling capacity credits and then exporting the power from the same generator to a neighboring market with higher prices. The fourth issue (mentioned by 10%) is the uncertainty regarding the availability of the generation capacity that has sold credits under actual scarcity conditions. As remuneration from the capacity market is not linked to performance under scarcity conditions, a concern is that some of the generators that have received capacity payments may not be able to honor their commitments during a scarcity event. This could be a special concern with nontraditional resources, such as demand response.

7.4.1.2 Capacity market performance

The experts generally contend that the capacity markets have achieved the goals of providing the required reserve margin, but in an economically inefficient way (54% agreed, 23% disagreed, and 23% had no opinion). In fact, the regions that have implemented capacity markets have achieved their reliability goals. For example, based on Base Residual Auction results for 2007/2008 through 2017/2018, the PJM-RPM was able to clear adequate capacity and meet reserve targets. This is partly due to the addition of a significant increase in new gas-based capacity. Several respondents suggested that capacity markets lead to excess generation capacity at the cost of the consumers.

In theory, price caps in wholesale electricity markets, used to mitigate market power in the US (FERC, 2014; Wilson, 2000), could adversely affect the incentive to invest in new capacity (Joskow and Tirole, 2007). Nevertheless, since required reserve margins are observed, capacity markets have been effective in achieving their adequacy goals compensating for the 'missing money' problem. However, because these capacity markets were implemented in electricity markets that already had surplus capacity (Spees et al., 2013), it is difficult to determine up to what extent the capacity markets were instrumental in achieving or maintaining the reserve margin levels.

7.4.1.3 Consumer benefits

The introduction of capacity markets has not led to an increase in consumer benefit, according to the respondents, as any potential benefit of the increased supply on electricity prices is offset by the additional costs arising from the capacity market itself. These costs appear to be mainly due to a higher reserve margin than would be economically optimal. Moreover, with respect to energy security, the availability of the additional generation resources remains uncertain. Some respondents cited the disconnection between capacity remuneration and scarcity performance as the reason for these concerns.

There may be difference in calculating the value of capacity credits for renewable resources in different market regions. A higher capacity credit could result in greater revenues from the capacity market for the renewable generators. According to the survey, 41% respondents agreed that differences in calculating capacity credits could have an impact on capacity market performance, 23% were of the opinion that there is no or minor impact, and 36% had no opinion. The results indicate that it is conceivable for the renewable generators to take advantage of differences in accounting of RES capacity in different regions by operating on the market that provides them with the best possible return, which might not be the same as the market where their production would be most valuable. Moreover, allocating a high volume of capacity credits to generators of variable renewable energy could negatively impact capacity market performance by driving down market prices, thereby reducing its effectiveness in providing incentive for investment in new generation capacity.

7.4.1.4 Cross-border effects

According to 28% of the respondents, cross-border effects currently are not considered a major concern in the US compared to other identified challenges. This appears to be due to the fact that so far, the regions under consideration have adequate reserve margins. However, cross-border effects are considered a potential future concern, when uneven distribution of generation resources due to the retirement of older coal-based generating units, in part due to the USEPA Clean Power Plan (USEPA, 2014), may exacerbate the free-ridership issue.

According to the survey results, 36% respondents opined that permitting imports to participate in the capacity markets would have a positive impact on the importing market (provided that regulations ensure a level playing field), as imports could reduce the overall system costs and may also encourage investment in merchant lines in regions of congestion; 28% were of the opinion that imports could have adverse effects and 36% offered no opinion on this issue.

Possible seams issues in the United States can be illustrated with a case mentioned in the survey result. Seams issues were observed between the PJM region, which at the time had implemented a capacity market, and the MISO region, which at that time had not implemented a capacity market. Competitive resource providers from the MISO region had greater incentives to offer their resources to the PJM-RPM than to MISO's energy-only market. Allowing these imports to operate in the capacity market by PJM dampened capacity prices under the RPM and increased risk to resource adequacy in MISO. At the same time, concerns were raised regarding the actual availability of these resources when required during scarcity conditions due to possible transmission constraints (such as a mismatch in the calculation of transmission capacity between the two regions by the ISOs) and curtailment during emergencies. The survey respondents noted that the need to reduce incentives for generators to export was a key driver in implementing a capacity market in the MISO region.

7.4.2 Advice to the EU

The survey results offer little support for the implementation of capacity markets by the EU member states. There is a clear preference towards depending on energy-only market to provide price signals for adequate investment. The respondents were asked directly, "As countries in EU begin to roll out capacity mechanisms, what advice might you offer to them regarding implementation of capacity markets / mechanisms?" In response, 41% of the experts surveyed advised the EU not to implement capacity markets and 5% had no opinion. All of the respondents (except the 5% with no opinion) provided advice about implementing capacity market. The most commonly mentioned suggestions are presented below.

In the event that capacity markets are implemented, the operators should ensure consistent and transparent rules right from the beginning, with minimum modifications once the capacity market is operationalized. This is crucial because administrative conduct can have a strong impact on the capacity market performance. Second, if importers are allowed to participate in capacity markets, it is important to have common definitions for capacity products among different regions. Third, the remuneration for capacity should be linked to the resource provider's performance during scarcity periods, when in fact the capacity is most required. Finally, the sloping demand curve for capacity market clearing that is already being utilized in two (NYISO and PJM) capacity markets in the United States is highly recommended.

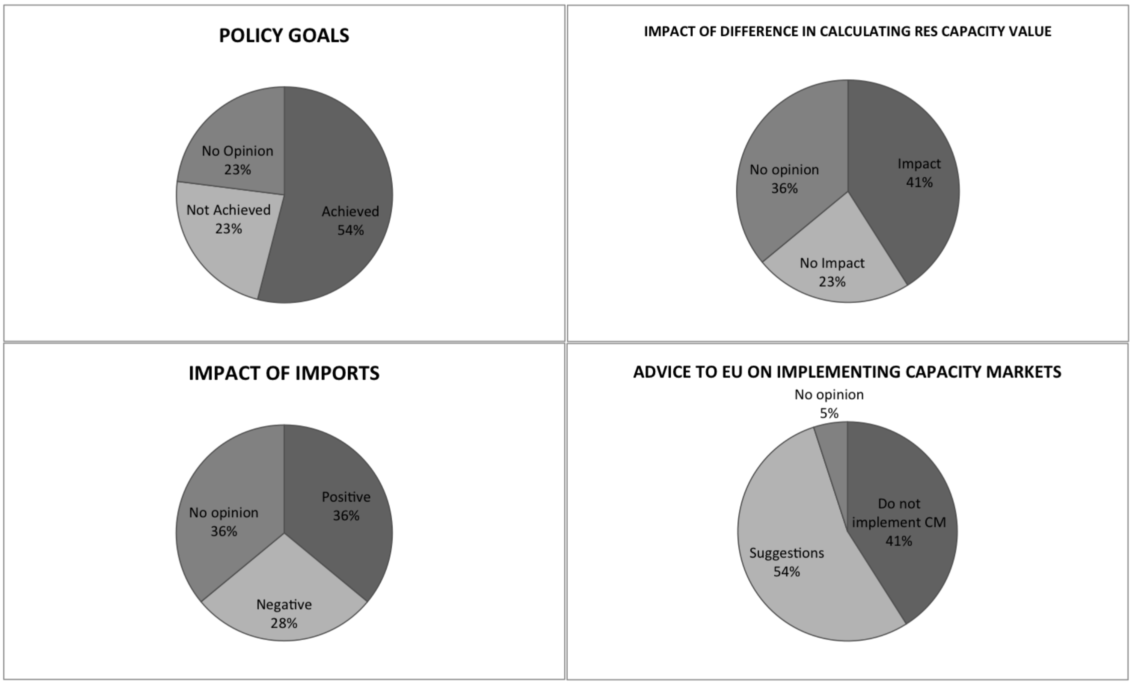

Figure 7.2: key survey results

7.5 Conclusions

Based on this survey, US experts generally recommend the use of energy-only markets over capacity markets. If a capacity market were to be implemented in the EU, the respondents recommend consistent and transparent rules, common definitions for capacity products, remuneration of providers based on performance during conditions of scarcity, and the use of a sloping demand curve for capacity market clearing.

Another relevant finding for Europe was that in cases when a capacity market allowed generators from neighboring areas to sell capacity in its market, capacity prices were dampened. This ‘capacity migration’ put pressure on the exporting regions to implement a capacity market as well. The respondents did not view the seams issues as a pressing concern in the US at present, but it was recognized as a potential future issue.

The key concerns about the US capacity markets that emerged from the survey were uncertainty regarding the availability of generation resources that clear the capacity market during scarcity hours, a mismatch of capacity auction time frames, opportunities to exercise market power, and regulatory uncertainty associated with changes to market rules. According to the survey respondents, capacity markets in the United States achieve their goals with respect to reliability, but they do so in an economically inefficient manner because they tend to lead to excess generation capacity. As a result, the implementation of capacity markets has not benefited consumers in the form of lower overall consumer costs.

8. Conclusions and discussion

8.1 Overview

In response to the concerns regarding generation adequacy, capacity mechanisms are being considered or have already been implemented by various member states of the EU. However, in a highly interconnected electricity system, such as the one in Europe, there appears to be a risk that the uncoordinated implementation of capacity mechanisms may cause unintended cross-border effects.

This research explored the performance and cross-border effects of various capacity mechanism in the presence of a high share of RES based generation. The performance criteria were the effectiveness of the capacity mechanisms in achieving the intended policy goals, their impact on the long-term development of electricity markets in the presence of a growing share of renewable sources in the supply mix and the cross-border effects caused by the implementation of these instruments in interconnected markets. This doctoral research addressed the following research question:

How to maintain security of supply during the transition to a low carbon energy system?

The research question was investigated using quantitative and qualitative methods. The quantitative analysis involved an agent-based modeling methodology, which was augmented by a qualitative survey study.

Two capacity mechanisms, namely a strategic reserve and a capacity market, were modeled as extensions to the EMLab-Generation agent-based model. Furthermore, two variations of a capacity market were analyzed. The first was a yearly capacity market design based on the NYISO-ICAP and the second was a forward capacity market with long term contracts based on the UK capacity market design. A survey of experts on the US capacity markets balanced the modeling work with empirical insights.

In an electricity market with a growing share of renewables, some form of long-term incentive appears to be required to ensure security of supply. In an isolated system, both a strategic reserve and a capacity market would improve the adequacy levels in the system. However, a capacity market appears to perform better than a strategic reserve in terms of providing a stable reserve margin in a scenario with high RES penetration. The capacity market is also able to perform well in a scenario with a demand shock. A capacity market does not provide sufficient incentive for investment in nuclear power plants. Investment in nuclear power would require separate policy support, as is implemented in the UK.

In the representation of an interconnected system in EMLab-Generation, both capacity mechanisms have a positive spillover on the neighboring energy-only markets in terms of adequacy. Therefore the neighboring markets would free ride on the capacity mechanisms. Generators in the neighboring region may be crowded out, but without loss of reliability. In order to reduce dependence on imports, the region may choose to implement its own capacity mechanism.

The US capacity market experts surveyed generally recommended the use of energy-only markets over capacity markets. Main concerns are the uncertainty caused by incremental changes to capacity market design and regulations. If a capacity market were to be implemented in the EU, the respondents recommended that policy makers should ensure consistent capacity market design and regulations in order to reduce regulatory risk. Cross-border effects of capacity markets are not viewed as a pressing concern in the US at present, but are recognized as a potential future issue.

8.2 Detailed conclusions

The main research question is divided into three key sub-questions that are addressed in this section.

- ***How do the selected capacity mechanisms perform in an isolated system?***
- ***How do the selected capacity mechanisms perform in the presence of a high share of variable renewable energy sources?***
- ***What are the cross-border effects of these capacity mechanisms?***

In this section these sub-questions are addressed based on the model results and the results from the survey of experts that have been discussed in preceding chapters. The first two sub questions are addressed together for each capacity mechanism studied in this research. This is followed by the answer to the third question. In the final part of this section, conclusions from the expert survey on the US capacity markets are presented.

8.2.1 Strategic reserve

Based on the model results presented in Chapter 3, the strategic reserve design that is modeled in EMLab-Generation can have a stabilizing effect on an electricity market in a reasonably cost-effective manner, depending on the scenario. Early investment incentives improve the supply ratio and therefore reduce shortages. A strategic reserve may increase the net cost of electricity supply to consumers in a scenario without variable renewable energy, but in the presence of a high volume of variable renewable energy, it may reduce the cost to consumers because it has a stabilizing effect on investment cycles in thermal power generation capacity.

Two problems with a strategic reserve have been found. First, there is a risk of extended periods of high average electricity prices if the reserve fails to attract sufficient investment. For instance, imperfect investment decisions, as may be due to uncertainty regarding future demand growth, may still cause an investment cycle, resulting in high average electricity prices in some years. Second, the effectiveness of the reserve with respect to maintaining generation adequacy appears to decrease as the share of variable renewable energy grows. In this case, the reserve may need to be redesigned or replaced by an alternative capacity mechanism. The effectiveness of the reserve may be improved by increasing its volume. Increasing the dispatch price is less effective. Our long-term model of a strategic reserve also reveals what we describe as the dismantling paradox. If a reserve contains old units that should be dismantled, the presence of the reserve may cause undue life extension, whether these units are contracted in the reserve or not.

8.2.2 Yearly capacity market

The model results presented in Chapter 4 indicate that the yearly capacity market design that is modeled in EMLab-Generation can provide generation adequacy effectively in the presence of a high share of renewable energy and a demand shock. In the latter case, investment cycles may develop, but if the required reserve margin is high enough, security of supply is not strongly affected. In the presence of a growing share of renewable energy, a capacity market may reduce overall consumer costs as compared to a scenario without a capacity market due to the significant reduction in shortage hours (during which the price of electricity is assumed to be equal to the value of lost load). The capacity market would mainly lead to more investment in low-cost peak generation units because the additional generation capacity that is induced by the capacity market is not expected to operate many hours. In comparison to a strategic reserve, a capacity market appears to provide a more stable supply ratio, especially in the presence of a growing share of variable renewable energy sources.

The net cost to consumers from a capacity market is sensitive to the growth rate of demand, but results indicate that the instrument would remain effective under different demand growth conditions. A decline in demand combined with high penetration of renewables may exacerbate the cost recovery problem of thermal plants, resulting in a higher need for support from the capacity market in order to maintain the required level of adequacy. The opposite is true in a high demand growth scenario.

8.2.3 Forward capacity market

Based on the model results presented in Chapter 5, in a system with an ambitious renewable policy, implementation of a forward capacity market leads to a substantial reduction in the overall cost to consumers as compared to a baseline energy-only market, given the scenarios and the myopic investment behavior of the agents in this model. The reason is that the capacity price in a forward capacity market is less volatile and slightly lower on average than in a yearly capacity market. Like the yearly capacity market, the forward capacity market increases investment in low-cost peak generation capacity as compared to an energy-only market.

In a forward capacity market, reducing the capacity market price cap leads to a reduction in capacity price uncertainty. Similarly, a gentler demand slope (larger upper and lower margins) reduces capacity price uncertainty. The performance of the market does not change significantly if the contract duration is extended beyond ten years. Because the forward capacity market responds a little slower to changes, a demand shock leads to a lower reserve margin in the forward capacity market than in the yearly capacity market.

8.2.4 Cross-border effects of capacity mechanisms

Based on the model results presented in Chapter 6, in the representation of an interconnected system in EMLab-Generation, interconnection with a neighboring zone does not affect the ability of a capacity market to reach its adequacy goals. The neighboring zone may experience a positive spillover in terms of adequacy and therefore free ride on the capacity market, but may also become import dependent. The free riding could cause an increase in cost to the consumers in the capacity market. Generators in the neighboring energy-only zone may be crowded out and in some cases to the extent that an investment cycle develops.

The model results indicate that a strategic reserve would also have a positive spillover effect on a neighboring energy-only market, both in terms of reduction in shortage hours and cost to consumers. However, the presence of an energy-only market in a neighboring zone seems to have a negative effect on the performance of the strategic reserve with respect to security of supply, when compared to an isolated system with a strategic reserve. The cost of a strategic reserve to the consumers who pay for it would increase with a free riding neighboring region.

A capacity market could reduce the need for, but may also reduce the effectiveness of a strategic reserve implemented in an interconnected zone. However, a strategic reserve could reduce the crowding-out effect that is caused by the neighboring capacity market on its own market and thus lower the risk of investment cycles.

8.2.5 Expert survey on US capacity markets

A survey of experts on US capacity markets was conducted in November 2014. The goal of this survey was to provide insight and advice to the EU with respect to selecting, designing, implementing and administering capacity markets in a highly interconnected electricity network, based on the experience with capacity markets in the United States.

In the survey, experts on the US capacity market generally recommended the use of energy-only markets over capacity markets. If a capacity market were to be implemented in the EU, the respondents recommended consistent and transparent rules, common definitions for capacity products, remuneration of providers based on actual performance during conditions of scarcity, and the use of a sloping demand curve for capacity market clearing.

Another relevant finding for Europe was that in a capacity market in which generators from neighboring areas were allowed to sell capacity in its market, capacity prices were dampened. This ‘capacity migration’ puts pressure on the exporting regions to implement a capacity market as well. The respondents did not view cross-border effects of capacity markets as a pressing concern in the US at present, although it was recognized as a potential future issue.

The key concerns about the US capacity markets that emerged from the survey were uncertainty regarding the availability of generation resources that clear the capacity market during scarcity hours, a mismatch of capacity auction time frames, opportunities to exercise market power, and regulatory uncertainty associated with changes to market rules. According to the survey respondents, capacity markets in the United States achieve their goals with respect to reliability, but they do so in an economically inefficient manner because they tend to lead to excess generation capacity. As a result, the implementation of capacity markets has not benefited consumers in the form of lower overall consumer costs.

8.3 Policy recommendations

The European Union (EU) has been at the forefront of the renewable energy revolution and already has a large penetration of renewables in its supply mix; hence the 'merit order effect' is more prominent in the EU electricity market than elsewhere. The recently announced decommissioning of a significant volume of conventional generation capacity (Caldecott and McDaniels, 2014; Meyer and Gore, 2015), which is needed when variable resources are not sufficiently available, is indicative of the risk posed to the security of supply. The absence of storage technologies and demand response, coupled with the ever increasing share of renewable power generation would only further aggravate these risks. Therefore, considering the current scenario in the European Union, capacity mechanisms appear to be necessary for ensuring long-term security of supply.

A capacity market appears to be a better choice than a strategic reserve. Although a capacity market is a more complex mechanism to implement from a regulatory perspective, it is a robust construct and is more effective in reaching its adequacy goals.

However, capacity mechanisms such as capacity subscriptions (Doorman, 2003) and reliability contracts (Vazquez et al., 2002), that were not included in this study may also prove to be effective because they too control the total volume of capacity (they are "market-wide" mechanisms). Decentralized capacity mechanisms such as capacity subscriptions could be more effective in reducing free-riding as consumers choose and pay for the adequacy level required by them. Reliability contracts may have a better operational performance in terms of mitigating market power (De Vries and Hakvoort, 2004) as compared to a centralized capacity mechanism such as a capacity market. In EMLab-Generation, strategic behavior of generators such as the exercise of market power is not modeled. Correspondingly, consumer behavior has also not been modeled. Therefore, capacity subscriptions and reliability contracts have been left out of the scope of this doctoral thesis.

The main concerns of the surveyed US experts is the uncertainty caused by incremental changes to capacity market design and regulations. Such regulatory behavior is already evident in the EU from the example of the UK capacity market. The UK capacity market rules were modified between the first and the second auction. More reforms are expected before the next auction. Policy makers in the EU are advised to ensure minimum changes to the capacity market design and rules after implementation. This would require the implementation of a comprehensive capacity market design that accounts for all foreseeable contingencies.

The results from this research also suggest that a sophisticated capacity market design may not necessarily be more effective. A simple yearly capacity market may be able to accomplish the security of supply goals as well as a more complex forward capacity market. Therefore policy makers are advised to keep capacity mechanism designs as simple as possible. The NYISO-ICAP in the US is an example of a successful simple capacity market. A simple capacity market design would aid policy makers in ensuring a comprehensive design and in minimizing changes to the market design after implementation. Hence, from a security of supply point of view, a yearly capacity market design like the one described in Chapter 4 would be an adequate policy instrument.

In the EU, the decision whether or not to implement capacity mechanisms is left to the discretion of the member states. Although the overarching reason for the implementation of capacity markets is adequacy, the design of these mechanisms is dictated by local requirements and constraints. Implementation of different capacity mechanisms (or no mechanisms) thus seems inevitable.

Hence there may be a risk of unintended cross-border effects as observed from the modeling results presented in this doctoral thesis. However, as the current system evolves into a EU-wide common electricity market, the cross-border effects may not remain a big concern. The exception would be member states without a capacity mechanism that do not want to be import dependent; such member states may come under pressure to implement a capacity mechanism.

In the future, country specific capacity mechanisms may evolve into "locational" capacity mechanisms, This would create a system with a single electricity market and multiple capacity mechanisms to ensure adequacy in specific regions (member states).

Currently, storage technologies do not play a major role in the electricity market, while demand continues to remain inflexible. However, storage technologies and demand response could play a major role in the future electricity markets. As the costs of storage technologies drop, allowing them to participate in the capacity market may provide additional incentive for faster development and commercialization of these technologies. It is foreseeable that storage technologies combined with demand response could make capacity mechanisms redundant. In such a case, discontinuing them may prove to be challenging. Over time, policy instruments such as capacity mechanisms become difficult to discontinue as market parties become dependent on remuneration from such mechanisms in their investment and decommissioning decisions.

An exit strategy should be developed in case the capacity mechanism needs to be discontinued sometime in the future. In the context of a capacity market, an option would be to gradually reduce the reserve margin requirement (*IRM*) over the years. The reduction in reserve margin would lead to lower capacity prices. Eventually the capacity price would reduce to zero, at which point the mechanism could be discontinued.

Finally, the conclusions presented are based on the capacity mechanism design and parameters that were modeled in EMLab-Generation. Rigorous sensitivity analyses were conducted on each capacity mechanism to ascertain the robustness of these conclusions. It should be noted that an ill-conceived mechanism design or wrong parameter selection (such as *IRM* value) could lead to sub-optimal outcomes. Variation in mechanism design and parameter selection may lead to results that differ from the findings of this research. Moreover, capacity subscriptions and reliability contracts were kept outside the scope of this research due to modeling constraints.

Policy recommendations:

- A capacity market is preferred over a strategic reserve.
- The capacity market design should be kept as simple as possible.
- Minimal changes to capacity market design and regulation after implementation.
- A capacity market could be discontinued by gradually reducing the IRM requirement.

8.4 Reflections on the modelling approach

The research in this doctoral thesis is mainly conducted using the EMLab-Generation agent-based model. As is the case with any model, various assumptions were made while developing EMLab-Generation. These assumptions have already been documented in Chapter 2. This section provides reflections on the impact of these assumptions on the results reported in this thesis.

In EMLab-Generation, due to reasons of computational feasibility, the electricity demand is implemented as a segmented load duration curve. In this approach, the temporal relationship between different load hours is lost. Thus short-term operational constraints such as ramping and unplanned shutdowns of power plants are ignored. Furthermore, due to the inflexibility of demand, the clearing prices in the electricity market are either set by the marginal generator or at the value of lost load. These abstractions may have caused underestimation of the effect that intermittent renewable generation has on the development of the electricity market, especially its ability to serve peak load. The effect of renewables in an interconnected system with non-coincidental peak period is also lost. These assumptions can also be expected to have an impact on the electricity market prices and thus generator revenues from the electricity market.

In the context of the capacity market, the bid price depends on the revenue from the electricity market, while the bid volume is dependent of the capacity of the power plant available at peak demand. Therefore the implication of these assumptions on bidding on the capacity market needs to be studied in greater detail.

The capacity mechanism design was not adjusted for cross-border trade: neither cross-border trade of capacity rights or any kind of export restriction was included. It can be expected that the participation of imports may dampen prices in the capacity market and thus affect investment incentive.

The model does not include policy uncertainty, which may have a strong impact on investment decisions. There is no incremental modification in the capacity mechanism design based on its performance. Although policy uncertainty is a key concern, this model has specifically been developed for the purpose of studying the robustness of different capacity mechanisms and not to simulate the dynamics of policy level decision-making.

8.5 Further research

In this section, suggestions for future research to further expand our understanding of capacity mechanisms and the use of agent-based models are presented.

Cross-policy effects due to simultaneous implementation of capacity mechanisms and carbon emission reduction policies: In the EU, capacity mechanisms are being implemented in electricity markets that have pre-existing carbon emission reduction policies i.e., EU-ETS. While the intended effect of emission reduction policies is to penalize carbon dioxide emitters such as thermal power plants, a capacity mechanism remunerates such generation units. Therefore there is a risk that simultaneous implementation of these policies may lead to a sub-optimal policy outcome. This makes the analysis of cross-policy effects between these policy instruments extremely relevant in the context of the current policy discussions in the EU. Such an analysis using an agent based modelling approach would add significantly to our understanding of both these policies.

Impact of storage technology and demand response on the security of supply and on the need for capacity mechanisms: It is expected that demand response and storage technologies could play a major role in the future electricity system. The availability of low cost storage technologies would make electricity generated from variable renewable sources available during hours of peak demand, whereas flexible demand would reduce the demand for electricity (especially during periods of high prices). In such a situation, the need for thermal generating units for ensuring adequacy would diminish and with it the need for capacity mechanisms.

In this doctoral research, these technologies have been kept out of the scope of study. Two research gaps could be studied by implementing these technologies in an agent based model such as EMLab-Generation. The first is the impact of these technologies on the long-term development of the electricity market (especially on adequacy) as their market share expands. The second is the impact of these technologies on the effectiveness of and need for capacity mechanisms.

Effectiveness of capacity subscriptions and reliability contracts in providing generation adequacy: As mentioned earlier, an advantage of a decentralized capacity mechanisms such as capacity subscriptions (Doorman, 2003) is that it may reduce free-riding, while a reliability contract (Vazquez et al., 2002) may be more effective in mitigating market power (De Vries and Hakvoort, 2004) as compared to a more centralized approach such as a capacity market. The use of an agent-based model to analyze the impact of these mechanisms on the long-term development of the electricity market would provide valuable insights. In the context of EMLab-Generation, an extensive expansion of the model to include strategic behavior of generators and a detailed representation of consumer behavior would be required.

Impact of short-term market dynamics on effectiveness of capacity mechanisms: As discussed in the thesis, the EMLab-Generation model currently utilizes a stylized load duration curve approach for modeling short-term market clearing. This causes the short-term dynamics to be less precise and the temporal relationship between different load hours being lost. Future research on the impact of short-term market dynamics on the effectiveness of capacity mechanisms is needed.

Impact of investment strategies on development of the electricity market: In liberalized electricity markets, every investor has its own set of criteria for making investment decisions in new generation capacity. These strategies may have a significant impact on the development of the electricity market. An electricity model that allows the user to equip agents (power generation companies) with different investment strategies would provide interesting insights into electricity market development and impacts on adequacy policies. These strategies could be based on concepts such as conditional value-at-risk (CVAR) and constant absolute risk aversion (CARA). Such a modeling extension would push the boundaries of using bounded rationality for modeling agent behavior.

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Appendices

A. Fuel price trend assumptions

Type	Unit	Coal	Gas	Lignite	Uranium	Biomass	Demand
Start	€/GJ	3.6	9.02	1.428	1.29	4.5	-
Lower	[%]	-3	-6	-1	0	-3	1
Upper	[%]	5	8	1	2	5	5
Average	[%]	1	1.5	0	1	1	1.5 or 1

B. Initial demand values for the load-duration curve

Table B.1: Initial demand values (Chapter 3, 4 and 6)

Segment	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
Demand (GW)	35.3	36.7	40.4	43.6	45.6	47.4	49.4	51.4	53.7	56.1	58.4	60.2	62	63.7	65.6	67.8	71.2	75.4	77.4	79.9

Table B.2: Initial demand values (Chapter 5)

Segment	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
Demand (GW)	21.6	22.8	24.2	26.6	29.2	30.7	32.5	34.4	36.6	38.7	40.5	42.3	43.8	46.3	48.4	50.4	52.3	53.8	55	56.7

C. Initial supply-mix

Table B.0.3: Initial supply mix for all scenarios (Chapter 3, 4 and 6)

Technology	Coal	CCGT	OCGT	Nuclear
% Share	50.0%	19.0%	13.0%	18.0%

Table B.0.4: : Initial supply mix for all scenarios (Chapter 5)

Technology	Coal	CCGT	OCGT	Nuclear	Wind	Hydro	Biomass
% Share	25.0%	39.0%	1.2%	13.3%	16.4%	1.6%	3%

D. List of survey questions

Sr. No.	Questions
1	What are the biggest challenges faced by the market participants in the US (or your region) with regard

	to the seams issue due to capacity markets?
2	According to you, how can these seams challenges be better managed?
3	Do the ISOs in the US (or your region) have mechanisms to monitor and mitigate unforeseen seams issues? (If yes, please describe)
4	In your experience, has implementation of a capacity market in one region caused a neighbouring region to implement capacity mechanisms to counter negative spill overs? Please provide examples (reference appreciated)
5	As countries in EU begin to roll out capacity mechanisms, what advice might you offer to them regarding implementation of capacity markets / mechanisms?
6	What were the goals of implementing capacity markets in the US (or in your region) and have they been achieved? Please elaborate.
7	In your opinion, have implementation of capacity markets led to an increase in security of supply and higher level of available capacity in regions implementing capacity markets? Please give reasons for your answer. (Any reports or links that you could bring to our attention would be appreciated)
8	If your answer to the above question is yes, has any tendency of free riding by a neighbouring region (where, consumers from interconnected regions attain higher security of supply without paying for it, due to the higher available capacity in the region with a capacity market that may delist and offer itself in the other market) been observed? Please provide an example if possible. (Reports or links appreciated)
9	If you agree that free riding occurs, has the free-riding on the security of supply led to a rise in plant retirements (and/or mothballing) in these neighbouring market zones (without capacity mechanisms)? What is your opinion on possible exacerbation of the "missing money problem" in these energy-only markets due to availability of cheap imports?
10	In an interconnected system, has the implementation of capacity markets had any impact on the wholesale electricity prices in neighbouring regions? If yes, what were these effects?
11	After the implementation of a capacity market, has a shift in investment towards the region with a capacity market occurred? If yes, how strongly has this shift affected investments in neighbouring regions? Please provide an example. (Reference appreciated).
12	How has allowing imports to bid on the capacity market affected the overall performance of capacity market and the electricity market as a whole?
13	What is your opinion on the risk of imports committed on the capacity market not being able to deliver and honour their contracts when required, due to regulatory uncertainty such as suspension of market rules? If such a situation has occurred in your knowledge, please provide example. (Reference appreciated)
14	In interconnected regions both having capacity markets, would differences in calculation of capacity credits for renewables affect the effectiveness of the capacity market performance? (With renewables committing to a market providing a higher capacity credit value). Please elaborate and provide your opinion
15	We welcome further remarks and opinions from you on the seams-issues caused by the implementation of capacity markets.

E. Additional sensitivity analysis

This section of the appendix provides additional sensitivity analysis of parameters used in this research.

F.1 Value of lost load

A value of lost load (VOLL) of 2000 €/MWh has been selected for use in this thesis. As mentioned in Chapter 3, estimating the value of lost load is difficult and widely varying estimates of VOLL are presented in literature. The sensitivity of the model to change in value of lost load is tested. The model is run in an energy-only configuration with three different VOLL namely 2000, 4000 and 6000 €/MWh. In order to minimize the uncertainty in the model, the fuel price do not vary and demand growth rate is kept at zero. There is no renewable energy policy implemented in these scenarios.

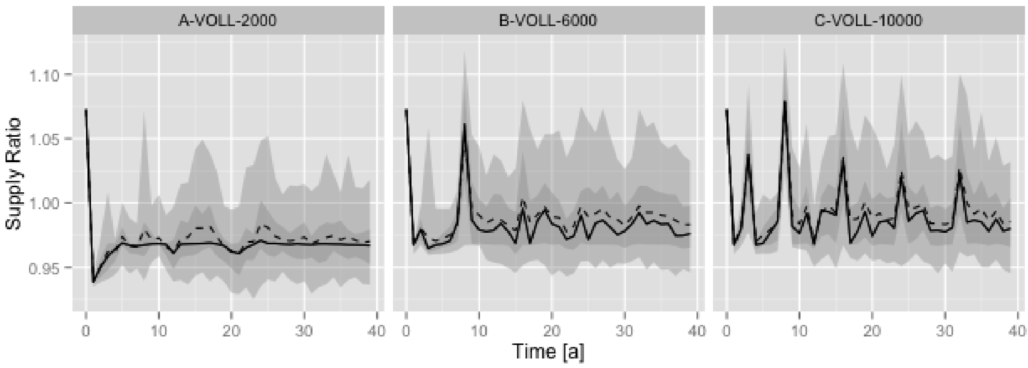

Figure 0.1: Supply-ratio for scenarios with different value of lost load.

On an average higher supply ratios are observed with increase in the value of lost load. A higher value of lost load leads to a stronger investment incentive and thus more investment in generation capacity. However, the increase in value of lost load also makes the supply ratio more volatile. This can be attributed to the over-investment due to higher expected revenues due to the higher VOLL values.

F.2 Weighted average cost of capital (WACC)

In this research a loan interest rate (i_l) of 9% is used. The sensitivity of the model to change in loan interest rate is tested. The model is run in an energy-only configuration with high ((i_l set at 9%), medium (i_l set at 6%) and low (i_l set at 3%) interest values. In order to minimize the uncertainty in the model, the fuel price do not vary and demand growth rate is kept at zero. There is no renewable energy policy implemented in these scenarios.

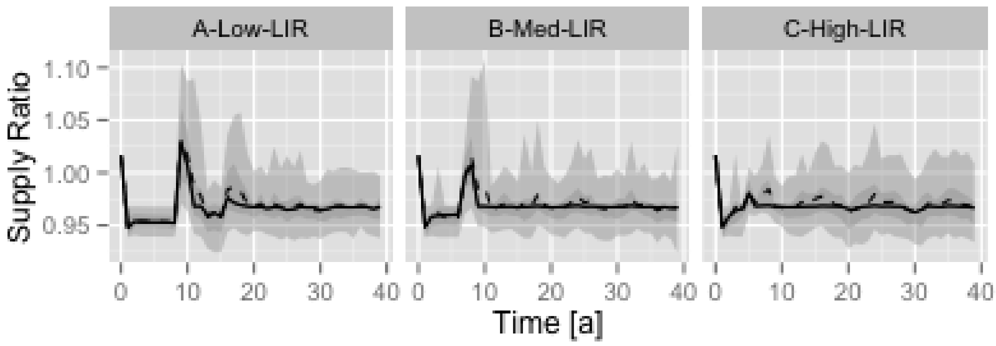

Figure 0.2: Supply-ratio for scenarios with different interest rates.

Lowering the interest rate causes the power generation companies to become less risk averse. This reflected by slightly higher supply ratios (and total installed capacity) in the scenarios with lower interest rates. However, the change in interest rate does not have a significant impact on the supply ratio. This is due to the profit based dismantling algorithm that leads to decommissioning of unprofitable units over time. Moreover, a shift from coal towards investment in IGCC, Nuclear technology based generation is also observed with reduction in interest rates. With lower interest rate there is a significant reduction in cost of debt. The lower costs along with high expected running hours (low marginal costs) make investment in these generation technologies more attractive.

F. Example of trends for demand growth and fuel prices

F.1 Example of demand growth trend

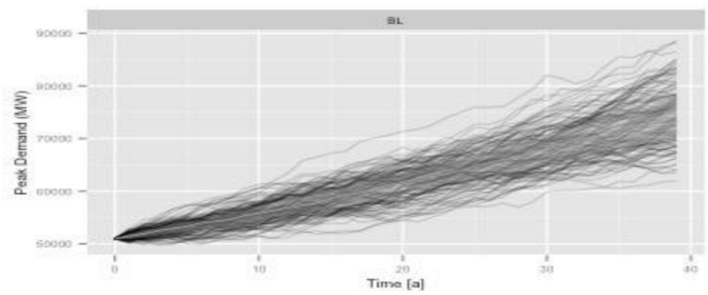

Figure F.1: Example of demand growth trend.

F. 2 Example of fuel price trends

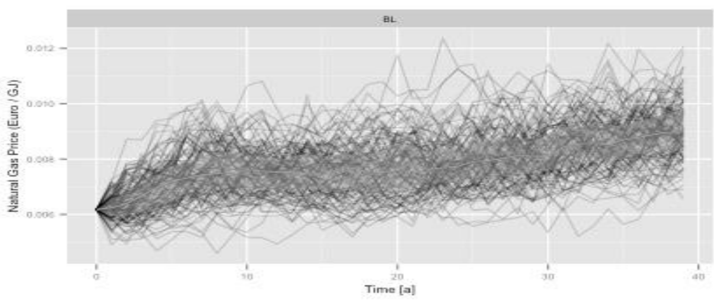

Figure F.2.1: Example of natural gas price trend.

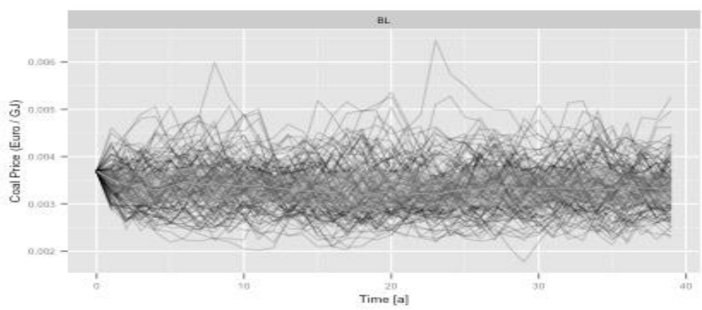

Figure F.2.2: Example of coal price trend.