Utilities Policy 48 (2017) 76–91

Contents lists available at ScienceDirect

Utilities Policy

journal homepage: www.elsevier.com/locate/jup

The effectiveness of capacity markets in the presence of a high portfolio share of renewable energy sources

Pradyumna C. Bhagwat [a, b, *], Kaveri K. Iychettira [a], Jörn C. Richstein [a, c], Emile J.L. Chappin [a], Laurens J. De Vries [a]

[a] Faculty of Technology, Policy and Management, Delft University of Technology, Jaffalaan 5, 2628 BX, Delft, The Netherlands
[b] Florence School of Regulation, RSCAS, European University Institute, Il Casale, Via Boccaccio 121, I-50133, Florence, Italy
[c] DIW Berlin, Mohrenstraße 58, 10117, Berlin, Germany

ARTICLE INFO

Article history:
Received 9 February 2016
Received in revised form
5 September 2017
Accepted 5 September 2017
Available online 14 September 2017

Keywords:
Adequacy policy
Capacity markets
Security of supply

ABSTRACT

The effectiveness of a capacity market is analyzed by simulating three conditions that may cause sub-optimal investment in the electricity generation: imperfect information and uncertainty; declining demand shocks resulting in load loss; and a growing share of renewable energy sources in the generation portfolio. Implementation of a capacity market can improve supply adequacy and reduce consumer costs. It mainly leads to more investment in low-cost peak generation units. If the administratively determined reserve margin is high enough, the security of supply is not significantly affected by uncertainties or demand shocks. A capacity market is found to be more effective than a strategic reserve for ensuring reliability.

1. Introduction

In this research, we analyze the effectiveness of a capacity market in the presence of a growing share of intermittent renewable energy sources. The European Union (EU) is at the forefront of the renewable energy transformation. The increasing reliance on electricity generation from variable renewable energy sources (RES) has led to concerns regarding the security of supply. The missing money problem and other vulnerabilities of the electricity markets due intermittent renewable energy resources in the supply mix have been extensively discussed in the literature (Borenstein et al., 1995; Brown, 2001; Pérez-Arriaga, 2001; Stoft, 2002; Woo et al., 2003; Joskow, 2006; De Vries, 2007; Bhagwat, 2016).

Concerns about the security of supply can be addressed by implementing capacity mechanisms to ensure adequate investment in generation capacity. These are sometimes considered as a means of providing stability during the transition to a decarbonized electricity system. A capacity market is a quantity-based mechanism in which the price of capacity is established in a market for capacity credits. In a capacity market, consumers, or agents on their behalf, are 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. Capacity markets have been discussed extensively in literature such as: Hobbs et al., 2001; Stoft, 2002; Joskow, 2008; Chao and Lawrence, 2009; Cepeda and Finon, 2011; Rose, 2011; Cramton et al., 2013; Finon, 2013; Mastropietro et al., 2015; Meyer and Gore, 2015; Höschle and Doorman, 2016; Bhagwat, 2016; Bhagwat et al., 2016a,b, 2017; Bothwell and Hobbs, 2017; Bushnell et al., 2017; Höschle et al., 2017.

In the literature, several types of computer models have been used to study capacity markets. Hach et al. (2015), Cepeda and Finon (2013) and Petitet et al. (2017) use a system-dynamic approach. Moghanjooghi (2016) uses probabilistic model. Botterud et al. (2002), Doorman et al. (2007), Dahlan and Kirschen (2014), and Mastropietro et al. (2016), use an optimization modeling approach. Ehrenmann and Smeers (2011) use a stochastic equilibrium model, while a partial equilibrium model is used by Traber (2017).

In the existing research, capacity markets are modeled without sufficient granularity to understand the operational dynamics of

* Corresponding author. Florence School of Regulation, RSCAS, European University Institute, Il Casale, Via Boccaccio 121, I-50133, Florence, Italy.
E-mail address: pradyumna.bhagwat@eui.eu (P.C. Bhagwat).

http://dx.doi.org/10.1016/j.jup.2017.09.003

these policy constructs and to compare different capacity mechanism designs. Moreover, none of the reviewed studies considered the combined effects of uncertainty and path dependence on the development of electricity generation portfolios with a growing share of RES. In reality, the ability of investors to make decisions is bounded and may lead to myopic investment decisions and consequently, suboptimal achievement of policy goals.

The use of an agent-based modeling approach allows us to study the development of the electricity market under imperfect information and uncertainty. Moreover, the use of EMLab-Generation allows higher granularity in modeling the capacity market. This work also extends the research on the effectiveness of capacity markets in providing reliability in the presence of demand shocks resulting in load loss and a growing share of renewable energy in the supply mix.

In the next section, we describe the EMLab-Generation model and its implications for implementing capacity markets. Section 3 describes the scenarios that we use. In Section 4, we present the results from our simulation of a capacity market implemented under various conditions. The conclusions are summarized in Section 5.

2. Model description

2.1. EMLab-generation

EMLab Generation is an open-source agent-based model of interconnected electricity markets that was developed with the aim of analyzing the impact of various carbon, renewable and adequacy policies on the long-term development of electricity markets. EMLab-Generation model was developed at Delft University of Technology.

Agent-based modeling utilizes a bottom-up approach in which key actors are modeled as 'agents' that make autonomous decisions, based on their interactions with the system and other agents in the model (Dam et al., 2013; Farmer and Foley, 2009). The advantages of using ABM in modeling complex socio-technical systems has been discussed (Chappin, 2011; Dam et al., 2013; Helbing, 2012; Weidlich and Veit, 2008). In the context of electricity markets, ABM captures the complex interactions between energy producers and a dynamic environment. No assumptions regarding the aggregate response of the system to changes in policy are needed, as the output is the consequence of the actions of the agents.

The main agents in this model are the power generation companies. They make decisions regarding bidding on the electricity market, investing in new generation capacity and dismantling existing power plants. Their decisions are based on factors endogenous to the model (such as electricity prices) as well as exogenous factors (such as different policy instruments, fuel price trends, and electricity demand growth trends). As the model is designed to analyze the long-term development of electricity markets, the simulation is run for a period of several decades, with a one-year time step.

Power-plant investment decisions are based on expected net present value. There are 14 different power generation technologies available for the agents to choose from in the model. The attributes of the power generation technologies, such as operation maintenance (O&M) costs and fuel efficiencies, are based on data from IEA World Energy Outlook 2011, New Policies Scenario (IEA, 2011). The assumptions regarding the power generation technologies are presented in Table 3 of the Appendix.

Electricity demand in the model is represented as a load-duration curve developed which is based on empirical data and approximated by a step function with multiple segments of variable length (Fig. 1). The advantages of using the load-duration curve approach in this model are described in (Richstein et al., 2014). In this model demand is inelastic to price.

The government sets annual targets for electricity generation from RES. In case the competitive generation companies do not invest enough in RES to meet the government target, a specific renewable energy investor will invest in the additional RES capacity needed to meet the target RES capacity, regardless of its costs. This way, the current subsidy-driven development of RES capacity is simulated. The variability or intermittency of renewables is approximated by varying the contribution of these technologies (availability as a percentage of installed capacity) to the different segments of the load-duration function. The segment-dependent availability of RES is varied linearly from a high contribution to the base segments to a very low contribution to the highest peak segment. (See Table 3 in the Appendix). A detailed description of how intermittency is modeled is available in De Vries et al. (2013) and in Richstein et al. (2015a, 2015b, 2014).

The power companies make price-volume bids for all power plants in their portfolios for each segment of the load-duration curve. The bids equal the variable cost and the available capacity of the underlying power plants. The electricity market is cleared for every segment of the load-duration curve in each time step. The market price for each segment is set by the highest clearing bid. If the supply is lower than demand, the clearing price for the segment is set to the value of lost load (VOLL). This causes high price volatility; demand elasticity would dampen prices, which in turn might reduce the propensity toward investment.

We consider an isolated electricity market (without interconnections). A detailed description of this model is available online in the EMLab-Generation technical report[1] and other previously published work (De Vries et al., 2013; Richstein et al., 2015a, 2015b, 2014; Chappin et al., 2017).

2.2. The capacity market module

The capacity market module in EMLab-Generation is a simplified representation of the NYISO-ICAP capacity market. We chose this for its relatively simple design, because it was one of the first capacity markets and because it is arguably meeting its policy goals. It is projected that no new resources would be required in the NYISO region till 2018 (Newell et al., 2009).

We start our description with the consumer side. Load-serving entities are obligated to purchase the volume of unforced

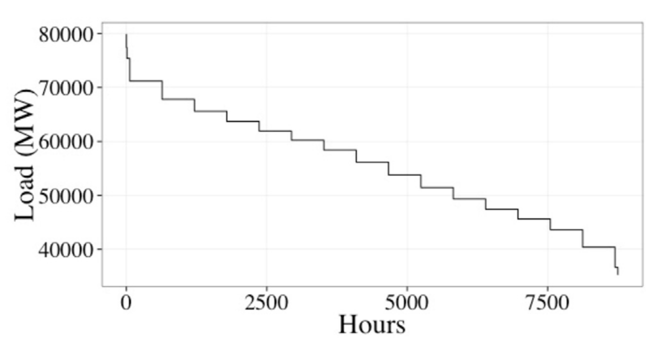

Fig. 1. Load-duration curve in EMLab-Generation for one country.

[1] www.emlab.tudelft.nl.

capacity (UCAP) that has been assigned to them (Harvey, 2005; NYISO, 2013a,b). UCAP is defined as the installed capacity adjusted for availability, as provided by the Generating Availability Data System (GADS) (NYISO, 2013a). 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 1 to October 31) and a Winter capability period (November 1 to April 30) (NYISO, 2014).

The NYISO determines the volume of unforced capacity that the load-serving entities must buy as a function of forecast peak load plus an Installed Reserve Margin (IRM), a security margin that is intended to limit the risk of generation shortfalls (NYISO, 2013a; Harvey, 2005). The IRM is defined as the required excess capacity (as a percentage of expected peak demand) and is established such that the loss-of-load expectation (LOLE) is once in every ten years, or 0.1 days/year. The LOLE represents the probability that the supply would be lower than demand, expressed in time units. In NYISO, days per year are used (Čepin, 2011).

The LSEs do not actively purchase the required capacity themselves; instead, the ISO contracts the required capacity from the capacity market on behalf of load serving entities (LSEs) and passes the cost along to them. To this end, once per year, the ISO organizes mandatory auctions for capacity for the coming year (NYISO, 2013a,b). In these auctions, supply-side bids of capacity are cleared against a sloping demand curve, which is administratively determined by the ISO. The parameters of the sloping demand curve are reviewed every three years. Market parties are allowed to correct their positions in secondary markets. 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, 2013a). Market parties are also allowed to conclude bilateral contracts. A detailed description of the market rules is available (NYISO, 2013a; Spees et al., 2013).

In the capacity market module of EMLab-Generation, the capacity for the coming year is traded in a single annual auction and is administered by an agent whom we call the capacity market regulator. Users set the IRM, capacity market price cap, and parameters for generating the slope of the 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.

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

We model a sloping demand curve for the capacity market like in the NYISO-ICAP and PJM-RPM capacity markets. These markets implemented sloping demand curves to provide more predictable revenues to generators and to lower consumer costs by reducing price volatility (Hobbs et al., 2007). With a sloping demand curve, 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 Fig. 2, 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

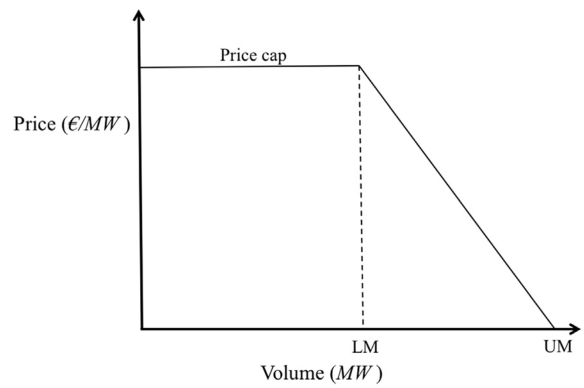

Fig. 2. Illustration of a sloping demand curve.

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

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. We use a marginal cost-based approach 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 were 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. For units that are not expected to make adequate revenues from the energy market to cover their fixed costs of remaining online, bids reflect the difference between the fixed costs and the expected electricity market revenue, the minimum revenue that would be required to remain online. Renewable energy generators are allowed sell capacity, but their UCAP is set equal to their contribution to peak load, which is only a small percentage in the case of solar and wind energy.

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 curved. The units that clear the capacity market are paid the market-clearing price. When making investment decisions, both commissioning and decommissioning, the power generators take into account the expected revenues from the capacity market.

3. Scenarios

In this section, we discuss the scenarios for the simulation runs.

Each scenario consists of 40 time steps 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 involve a renewable energy policy so as to address the

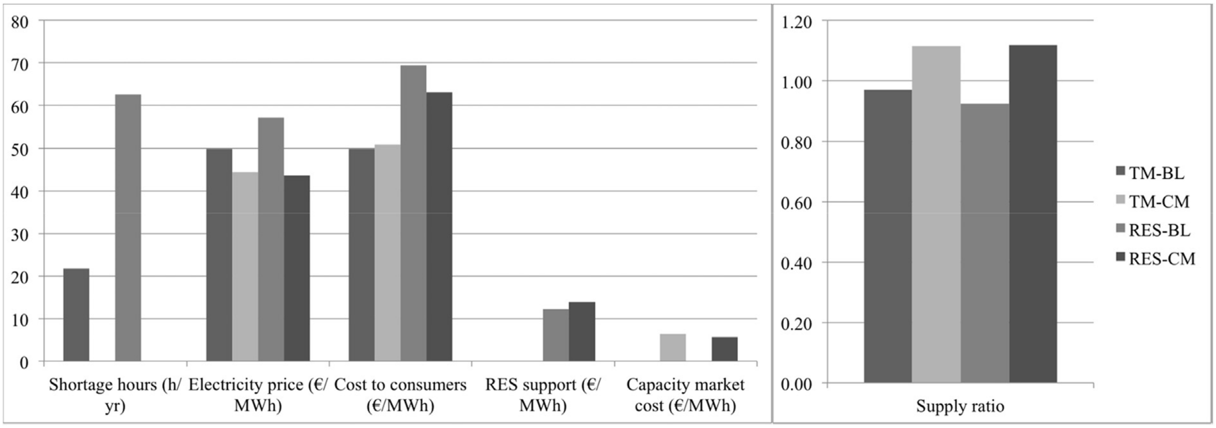

Fig. 3. Comparison of indicators for the TM and RES scenarios.

core research question regarding the effectiveness of capacity markets in regions with a growing share of renewables in their supply mix. The scenario settings are described in Table 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.

We consider a single electricity market without interconnections. 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). We introduce a renewable energy policy that causes rapid growth in the share of intermittent renewable energy resources over the period of the simulation. 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 and demand growth are modeled stochastically, based on a triangular, mean-reverting probability function. (See Table 5 in the Appendix). The coal and gas prices are based on fossil fuel scenarios published by the Department of Energy and Climate Change (2012) (Department of Energy and 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. Demand grows by 1.5% per year on average.

Estimating the value of lost load (VOLL) is difficult (Cramton et al., 2013; Stoft, 2002). The estimates of the value of lost load in the 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, VOLL was chosen at the relatively low level of 2000 €/MWh. We also chose this level to take into account demand flexibility that might occur during periods of high prices.

Table 1
Scenario parameters.

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

The scenario (RES-CM) consists of a capacity market with a capacity maximum price of 60 000 €/MW per year. We assume that the capacity market regulator requires a reserve margin of 9.5%[2] based on the NYISO-ICAP reserve margin requirement, which we lower to reflect the fact that we do not model generation outages. Lower and upper margins of 2.5% are introduced to generate a sloped demand curve. 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, 30% of the investment is financed with equity with an expected return on equity of 12%, and 70% is financed with 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 values used were based on Richstein (2015a,b).

We use the following indicators 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.
- The cost to consumers (€/MWh): the sum of the electricity price, the cost from the capacity market and the cost of the renewable policy (if applicable) per unit of electricity consumed.[3]

[2] Calculated as percentage of expected peak demand as explained in Section 2.2.

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

4. Results and analysis

4.1. Overview

Fig. 3 provides an overview of the results of the simulation runs. The results are also presented numerically in Table 4 of the Appendix.

At the start of the simulation run in the baseline scenario (TM-BL and RES-BL), we observe a decline in the supply ratio. 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 even a small level of demand response would lead to considerable reduction in shortage hours observe in the baseline scenarios.

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

We test the effectiveness of a capacity market in the absence of renewable energy policy (TM-CM) by comparing it to the baseline case without a capacity market (TM-BL). In our 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 Fig. 4). In this figure and others, the mean is indicated by a solid line, the average with a dashed line, the 50% confidence interval with a dark gray area and the 90% confidence interval with the lightly shaded area. The average capacity price is 36,496 €/MW. The observed overshoot in adequacy 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. 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 h/year in the baseline scenario to nil. The electricity price is 11% lower and volatility is also reduced, as can be seen in Fig. 5. 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.

The main impact of implementing a capacity market on the generation mix is a substantial 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 revenue from the capacity market is sufficient for OCGT capacity to remain online even when these units have very little or no revenue from the electricity market. Fig. 6 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.).

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 h/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 costs to consumers due RES.

A capacity market can compensate for this effect. A supply ratio of 1.12 is maintained fairly consistently in the model (Fig. 7), 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

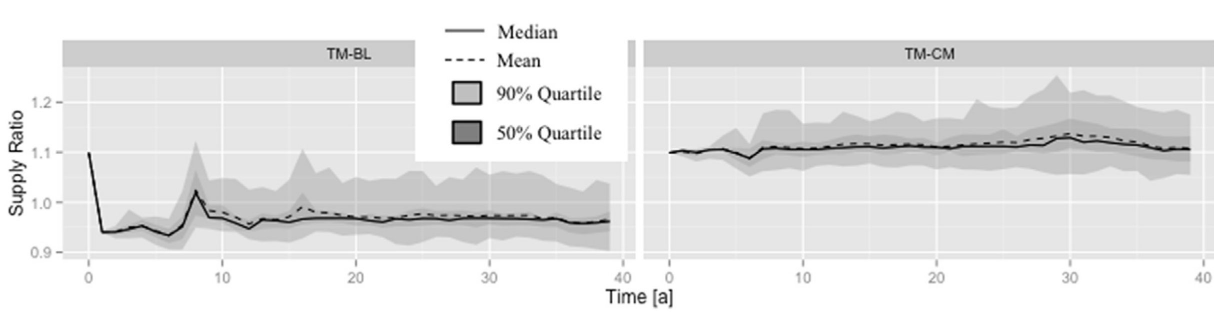

Fig. 4. Supply ratio in a scenario without a renewable policy without (left) and with (right) a capacity market.

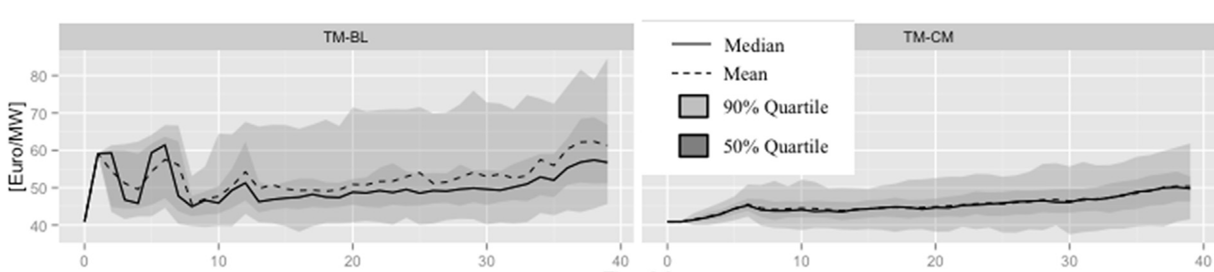

Fig. 5. Electricity prices in a scenario without a renewable policy, without (left) and with (right) a capacity market.

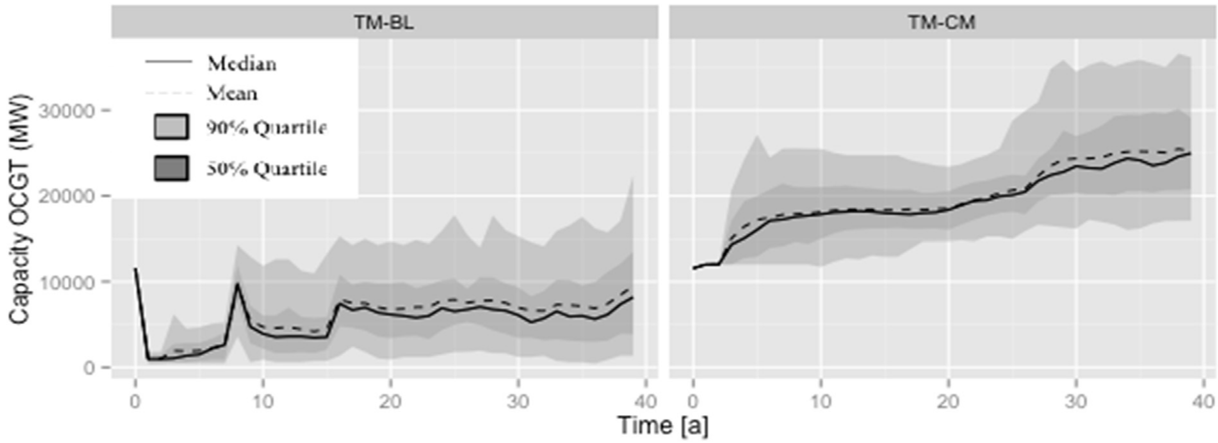

Fig. 6. Development of OCGT installed capacity.

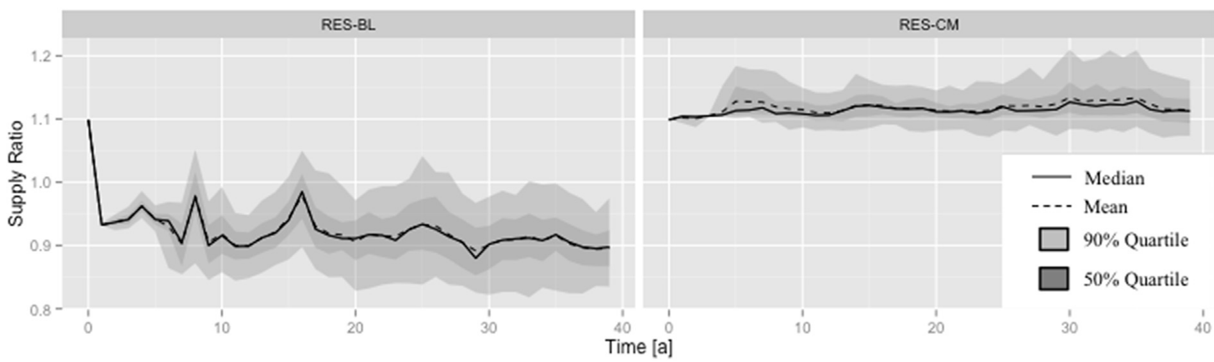

Fig. 7. Supply ratio in the growing share of renewables without (left) and with a capacity market (right).

than what is required to maintain the adequacy target (IRM). The average capacity market clearing price is 31,558 €/MW per year. We also observe 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 Fig. 11). However, the additional cost of RES support leads to higher net costs to consumers in the RES scenarios as compared to the thermal-only scenarios.

In our model, the presence of additional capacity eliminates shortages entirely (from 62.6 h/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 Fig. 8).

The total cost to consumers is 9% lower in the presence of a capacity market in the high-RES scenario. To understand this reduction, we analyze the impact of a capacity market on electricity prices and the cost of renewable energy policy. 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, which stem mainly from avoiding outages, are larger than the costs of the capacity market plus the higher renewable energy subsidy.

To provide insight on the effect of RES on the system, Fig. 9 illustrates the shares of different technologies in the generation mix

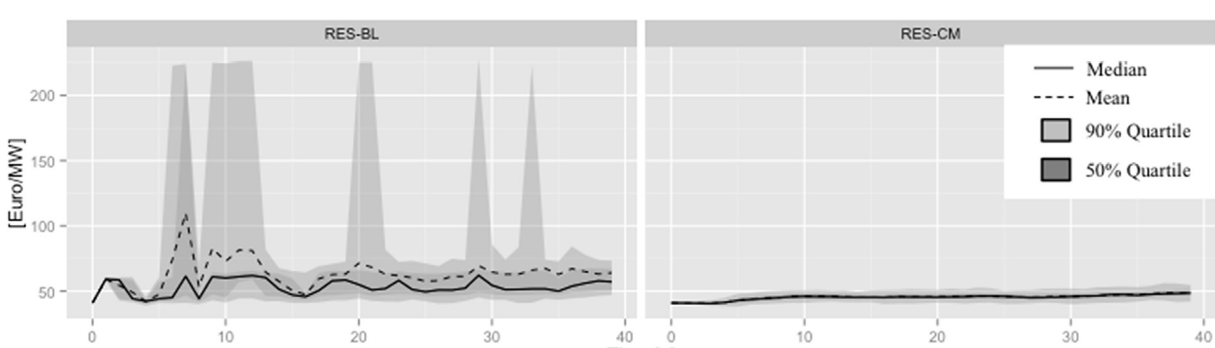

Fig. 8. Electricity price in scenarios with growing share of renewables without (left) and with a capacity market (right).

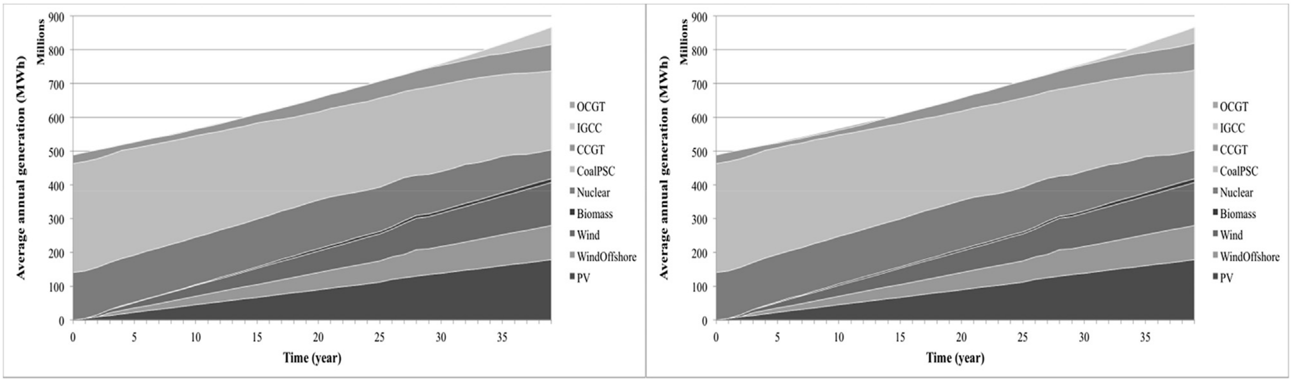

Fig. 9. Average shares of generation technologies in the energy supply mix in a scenario without (left) and with a capacity market (right).

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.) 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. The installed capacity of the various generation technologies at the end of the simulation is presented in Table 7 in the Appendix.

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 Fig. 10). The additional revenue from the capacity market is sufficient for additional OCGT capacity to remain online even when these units receive very little or no revenue 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). These conditions make 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 rarely runs, in which case the choice for OCGT, as the technology with the lowest capital cost, is logical. Fig. 10 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).

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 finding suggests that countries that desire new investment in nuclear power will need to implement a support policy, as corroborated by 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 we allow renewable power producers to offer the peak-available capacity of 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 (Fig. 11). 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.

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. We observe a modest impact on the model results. 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 Fig. 12.

Establishing a strategic reserve is an alternative to implementing capacity market. In earlier work, the effectiveness of a strategic reserve in the presence of a growing share of renewable energy in

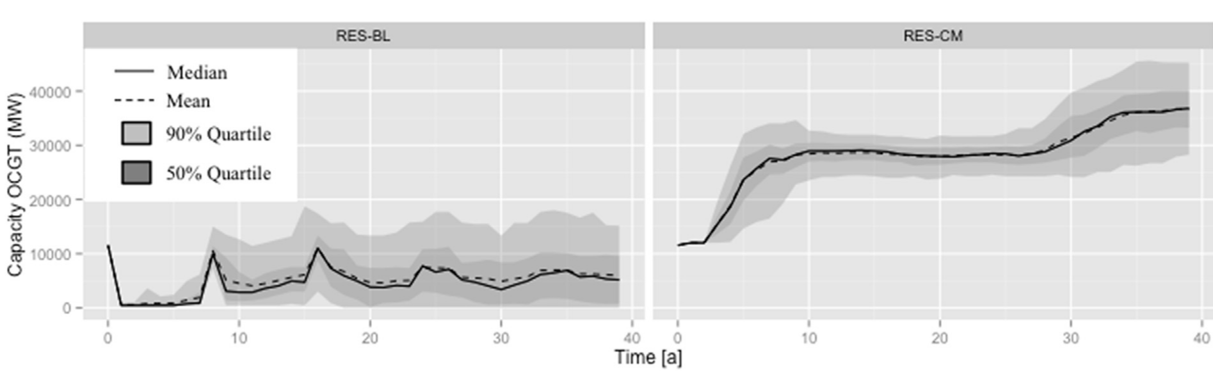

Fig. 10. OCGT development in the presence of a high share of renewables.

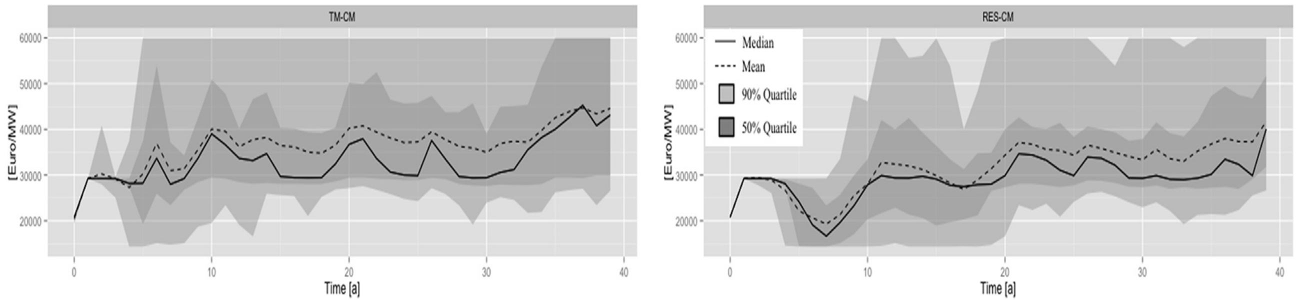

Fig. 11. Capacity market prices in scenarios without (left) and with a renewable energy policy (right).

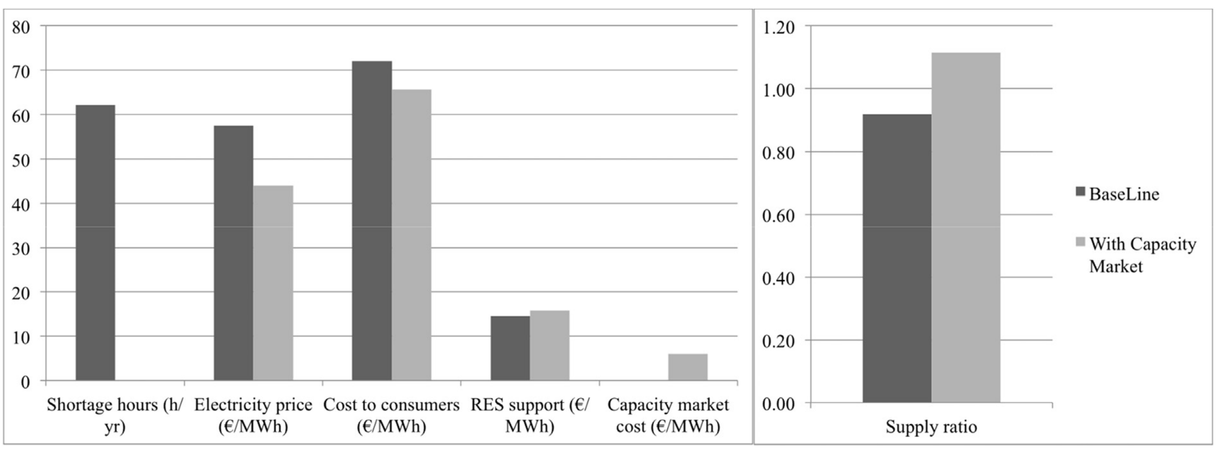

Fig. 12. Comparison of the scenarios with zero contribution of renewables to the peak.

the supply mix was analyzed (Bhagwat et al., 2016b). 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 our model, both capacity mechanisms reduce the net cost to consumers in the presence of imperfect information and potentially myopic decision-making. However, unlike the strategic reserve, the effectiveness of the capacity market in providing the required reserve margin does not decrease with an increase in the share of intermittent renewable energy. Capacity markets should help avoid uneconomic investment cycles. A comparative analysis between the performance of strategic reserves and capacity markets in the context of interconnected power systems with cross-border effects was presented in Bhagwat et al. (2017).

However, capacity mechanisms such as capacity subscriptions (Doorman, 2003) and reliability contracts (Vazquez et al., 2002), which 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 with regard to 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 was not modeled. Correspondingly, consumer behavior also was not modeled. Therefore, capacity subscriptions and reliability contracts are outside of the scope of this research.

4.4. Sensitivity analysis

As a sensitivity analysis, we assess the effectiveness of a capacity market with respect to differences in electricity demand growth and with demand shocks. We also test 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. The following Table 2 provides an overview of the scenarios for the sensitivity analysis.

4.4.1. The impact of demand growth on the effectiveness of a capacity market

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 2 (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 Fig. 13). A decline or no growth in demand combined with a high share of renewables in the generation portfolio 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 Fig. 14). Consequently, consumer costs are also higher as compared scenarios with medium or high growth rates (See Fig. 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%).

Table 2
Scenario settings for sensitivity analysis.

S. No.[a]	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

[a] Note: Scenarios 3, 6, 11 and 15 are same as RES-CM.

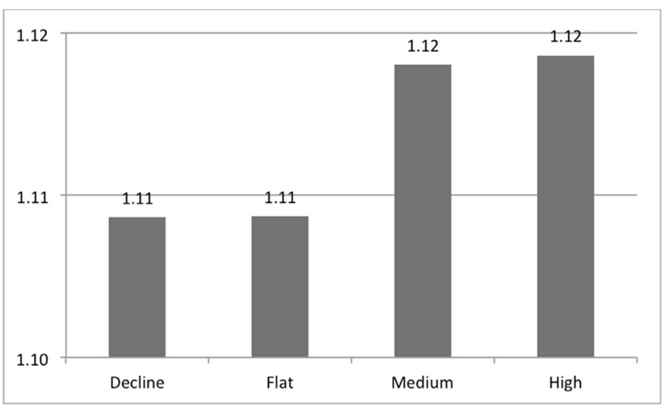

Fig. 13. Supply ratios in different demand growth rate scenarios.

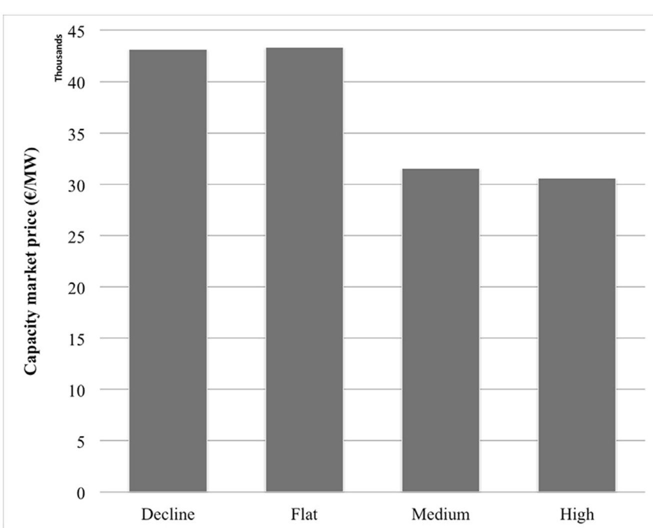

Fig. 14. Capacity market clearing price in different demand growth rate scenarios.

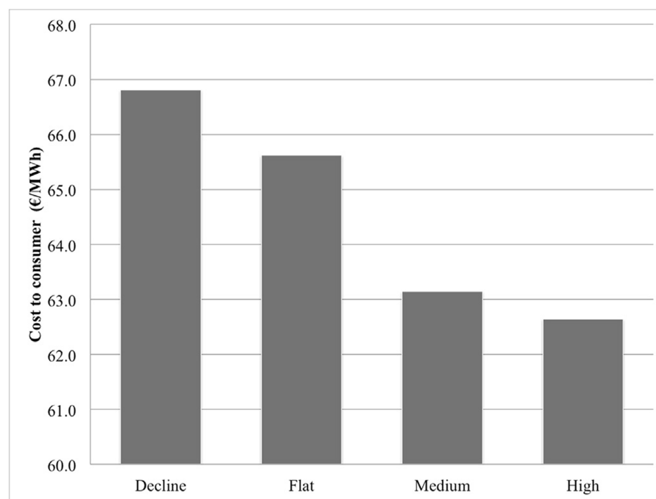

Fig. 15. The cost to consumers in different growth rate scenarios.

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

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

The model was run with an *IRM* between 6% and 18% in increments of 3 percentage points (See Table 2, Scenarios 5–9). All other parameters were kept the same as in the *RES-CM* scenario.

The results are illustrated in Fig. 16. The IRM targets are met (See Fig. 16). A higher IRM requirement leads to a higher capacity market clearing price (Fig. 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, including demand shocks, and thus lead to an adverse impact on consumer costs.

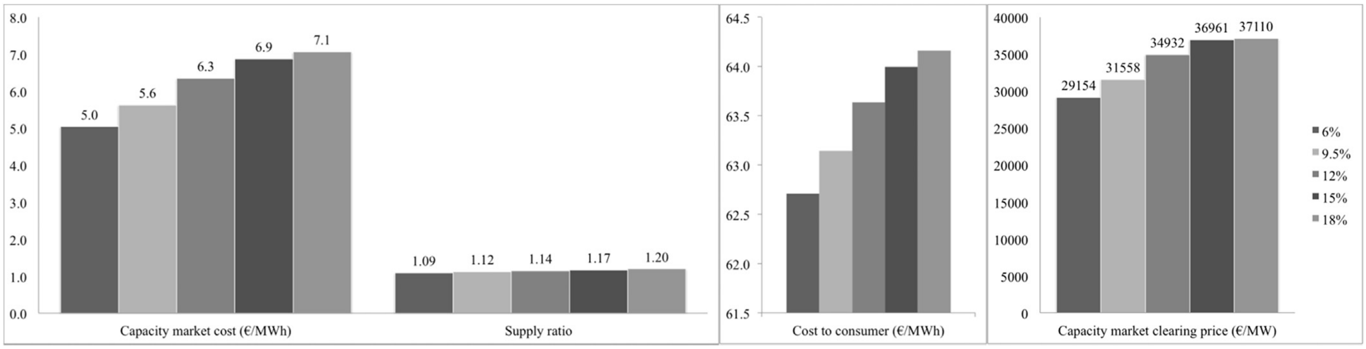

Fig. 16. Indicators for scenarios with different capacity margin values.

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 demand is higher than the available supply in the capacity market, and is expected to affect investment incentives. It has been suggested 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, 2013a; Sioshansi, 2011). We changed the level of the capacity market price cap in increments of 20 k€/MW per year, while keeping all other scenario parameters the same as in the RES-CM scenario (Table 2, scenarios 10–14).

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

We observe that the price cap has a significant impact on the volatility of the capacity market prices, as can be observed in Figs. 17 and 18. In all scenarios, the required reserve margin targets are achieved. The supply ratio in a 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 Fig. 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 volatility in the capacity market. In the initial years of scenarios with price cap greater than 40 k*€/MW,* we observe a dip in average capacity price, which can be attributed to 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 Figs. 18 and 19).

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 2.2, this is determined by the upper (*UM*) and lower (*LM*) margins. In this section, we increase the *UM* and *LM* in two increments of 2.5 percentage points. See scenarios 15–17 in Table 2. All other scenario parameters are kept 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. No significant difference is seen in either the average supply ratio or the average capacity market-clearing price. However, the volatility of the capacity market prices declines with increasing values of the upper (*UM*) and lower (*LM*) margins (Fig. 20).

4.4.5. The effectiveness of capacity market in the event of a demand shock

We modeled a demand shock to test the ability of a capacity market to cope with extreme events. The simulated demand

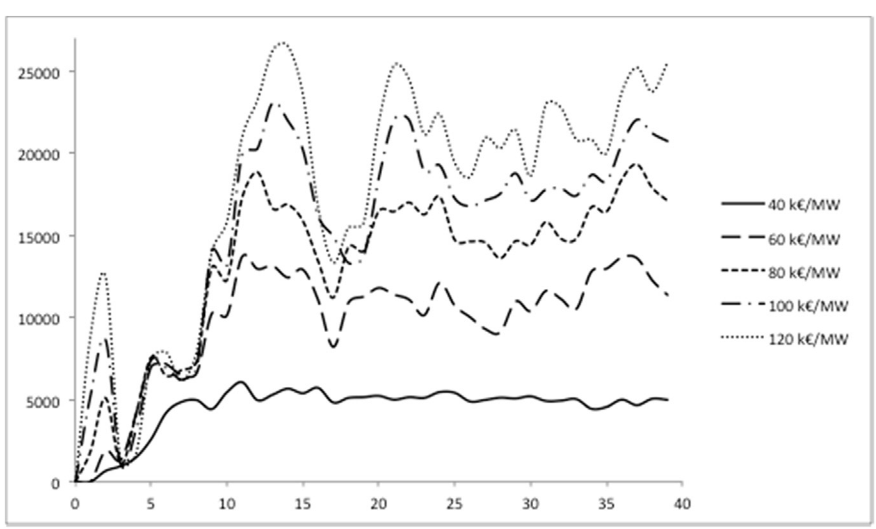

Fig. 17. Standard deviation of capacity market prices in scenarios with different capacity price caps.

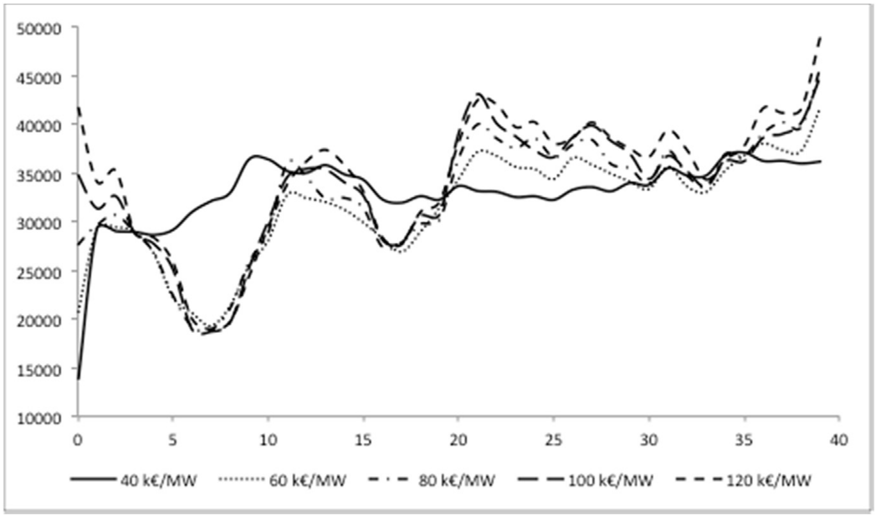

Fig. 18. Average capacity clearing prices in scenarios with different capacity price caps.

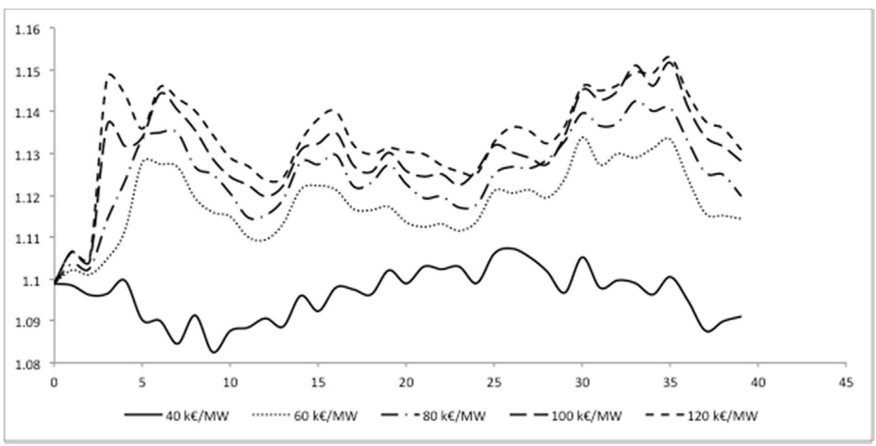

Fig. 19. Average supply ratios in scenarios with different capacity price caps.

trajectory is shown in Fig. 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.

Fig. 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, we see a gradual dismantling of excess capacity over the next years. We also observe an increase in the volatility of capacity prices (Fig. 23). 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. The uncertainty about the magnitude of future demand changes and investment cycles poses a difficulty for the regulator: setting the margin too high will cost the consumers money, setting it too low may result in shortages despite the implementation of a capacity market. However, the social cost of over investment is much smaller than the cost of shortage (Cazalet et al., 1978; De Vries, 2004).

4.5. *Reflection on the modeling approach*

To limit computational time, electricity demand is be modeled as a segmented load-duration curve. As a result, the temporal relationship between different load hours is lost. Thus, short-term operational constraints such as ramping and unplanned shutdowns of power plants were ignored. Furthermore, due to the inflexibility of demand, the clearing prices in the electricity market are either set by the marginal generator or the VOLL. These abstractions may cause underestimation of the effect that intermittent renewable generation has on the development of the electricity market. The effects of non-coincident renewable energy generation and peaks in demand are also lost. These modeling assumptions along with the segmented nature of the load-duration curve make capturing the short-term dynamics less precise and

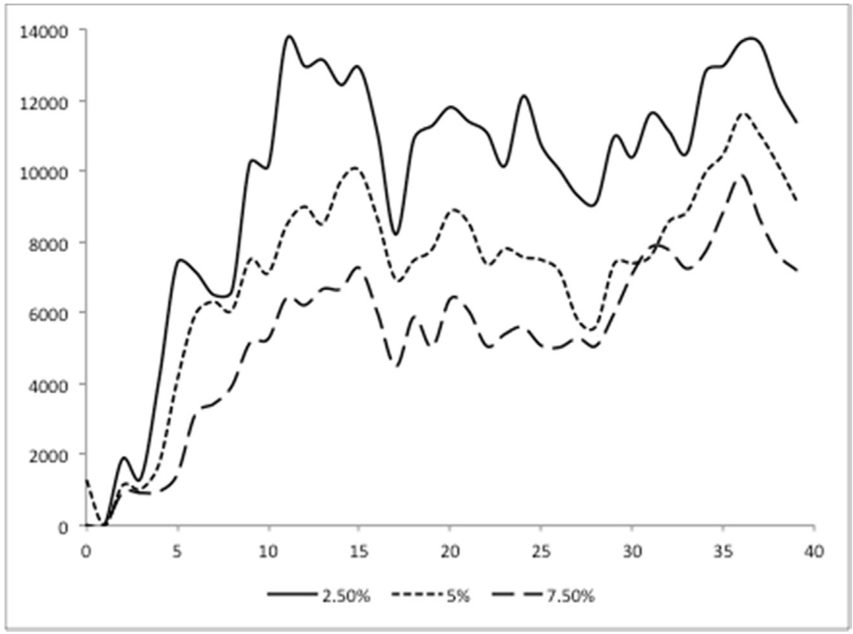

Fig. 20. Standard deviation of capacity market clearing prices at different demand curve margin levels.

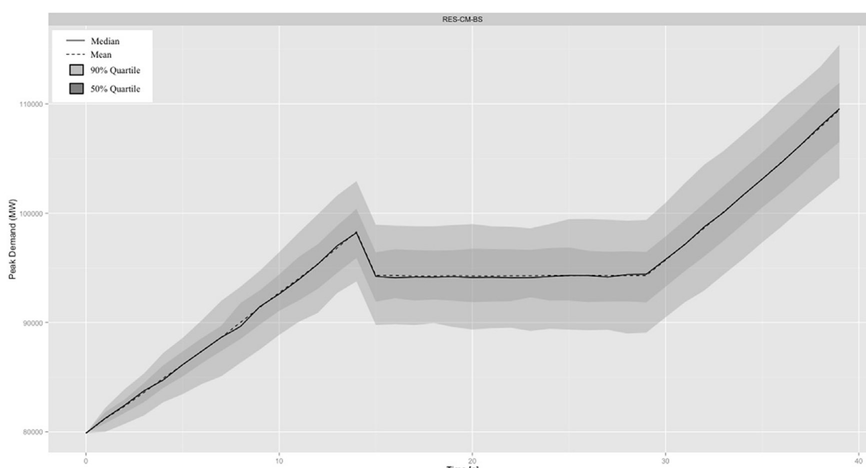

Fig. 21. Peak demand trend in scenarios with a demand shock.

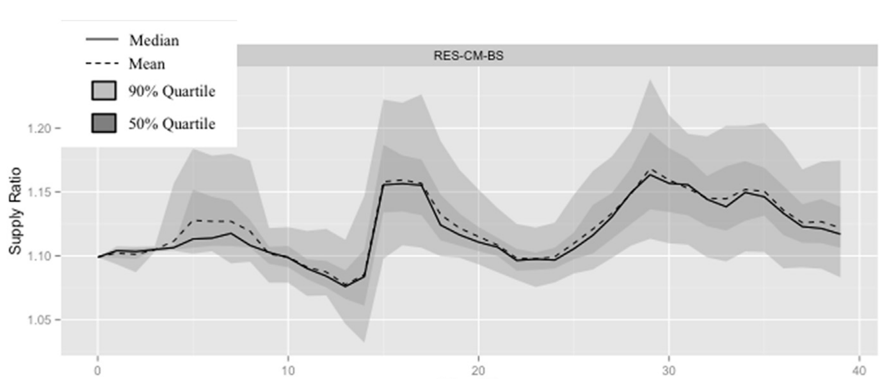

Fig. 22. Supply ratio in a scenario with a demand shock.

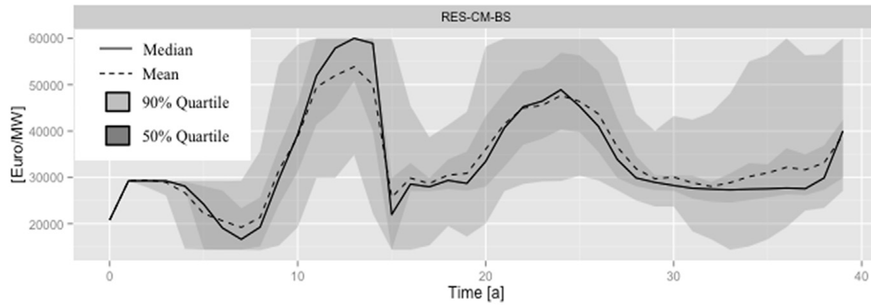

Fig. 23. Capacity market clearing price in a scenario with a demand shock.

explain the overshoot in adequacy that is observed in the model results. However, they do not change the effect caused by investment based on extrapolation of historic trends and combined with a construction delays.

The purpose of the model is to simulate realistic imperfections in investment behavior. In this study, we focused on uncertainty and a demand shock in order to analyze the robustness of a capacity market under these conditions. However, the capacity market in the model is idealized. Real capacity markets are vastly more complex, and the many associated rules entail risks of regulatory failure. The model does not include policy uncertainty, which may have a substantial impact on investment decisions. There is no period of regulatory uncertainty around the introduction of the capacity market, nor are there incremental modifications to the capacity market in the model. Therefore the model simulates a well-functioning capacity market within a suboptimal electricity market.

Network congestion and market power were left out of the scope. Therefore the dynamics that may arise due to the strategic behavior of various market participants, e.g., during shortages, are not captured. These effects may create further challenges for the implementation of a capacity market in practice. Demand response and storage have also been left out of the scope of this research because their impact is limited currently. They have a stabilizing impact on electricity prices and may reduce the need for a capacity mechanism in the long term.

5. Conclusions

We present a model of a capacity market in an isolated market with an ambitious renewable energy policy. While an energy-only market within an optimized investment equilibrium is optimal in theory, we show that a capacity market can be an effective remedy when less-than-optimal circumstances might lead to too little or too late investment in generation capacity. We simulate three types of conditions that may cause investment not to be optimal: imperfect information and uncertainty; a demand shock; and a growing share of renewable energy in the generation portfolio. Under these circumstances, a capacity market may provide a significant reduction in the number of shortage hours, as compared to an energy-only market. Due to the high social cost of outages relative to the limited additional investment in generation capacity, total social cost can be reduced. The net cost to consumers of a capacity market is sensitive to the growth rates of demand. 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.

If the administratively determined reserve margin is high enough, security of supply is not significantly affected by uncertainty or a demand shock. Uncertainty about future demand and investment needs presents a difficulty for the regulator: setting the margin too high will cost consumers money, while setting it too low may result in shortages despite the implementation of a capacity market. However, the social cost of over investment is much smaller than the cost of shortage. Capacity markets mainly lead 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 requires separate policy support, as is implemented in the UK.

We also find that a lower price cap reduces capacity market price volatility 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 volatility. Extending the upper (*UM*) and lower (*LM*) margins of the demand function also reduces capacity market price volatility.

A capacity market provides a more stable supply ratio and is therefore more effective than a strategic reserve in providing the required reserve margin, especially in the presence of a demand shock and a growing share of renewable energy. However, the EM-Lab model we used simulates a relatively ideal capacity market in the presence of imperfect investment behavior and markets. This leads to an optimistic assessment of capacity markets. Our results thus illustrate the potential benefits of a well-implemented capacity market without accounting for the inevitable complications, such as regulatory uncertainty or market power.

Acknowledgments

Pradyumna C. Bhagwat, Kaveri K. Iychettira and Jörn C. Richstein have been awarded the Erasmus Mundus Joint Doctorate Fellowship in Sustainable Energy Technologies and Strategies (SETS) hosted by the Universidad Pontificia Comillas, Spain; the Royal Institute of Technology, Sweden; and Delft University of Technology, The Netherlands. The authors would like to express their gratitude towards all partner institutions within the program as well as the European Commission for their support.

APPENDIX

Table 3
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%)

Table 4
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

Table 5
Fuel price and demand price growth rate 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	2
Upper	[%]	5	8	1	2	5	2
Average	[%]	1	1.5	0	1	1	1.5

Table 6
Initial supply mix for all scenarios.

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

Table 7
Development of installed capacity the supply-mix in a scenario with growing RES.

Technology	Initial Mix	RES-BL	RES-CM	RES-BL	RES-CM
		Final Mix	Final Mix	Final capacity (GW)	Final capacity (GW)
Coal	50.0%	20.2%	18.6%	45.4	45.7
CCGT	19.0%	10.4%	8.9%	23.4	21.8
OCGT	13.0%	2.4%	11.4%	5.4	28.0
Nuclear	18.0%	6.7%	6.1%	15.0	15.0
IGCC	–	0.4%	0.3%	0.9	0.8
Wind Offshore	–	7.4%	6.7%	16.5	16.5
PV	–	36.3%	33.2%	81.5	81.5
Wind	–	13.7%	12.5%	30.8	30.8
Biomass	–	2.4%	2.2%	5.4	5.4
CCGTCCS	–	–	–	0	0
CoalCCS	–	–	–	0	0
Lignite	–	–	–	0	0
Biogas	–	–	–	0	0
IGCCCCS	–	–	–	0	0
Total	100.0%	100.0%	100.0%	224.3	245.5

References

Anderson, R., Taylor, L., 1986. The social cost of unsupplied electricity. Energy Econ. 8, 139–146.

Baarsma, B.E., Hop, J.P., 2009. Pricing power outages in The Netherlands. Energy 34, 1378–1386.

Bhagwat, P.C., 2016. Security of Supply during the Energy Transition: the Role of Capacity Mechanisms. Delft University of Technology. http://dx.doi.org/10.4233/uuid:9dddbede-5c19-40a9-9024-4dd8cbbe3062.

Bhagwat, P.C., de Vries, L.J., Hobbs, B.F., 2016a. Expert survey on capacity markets in the US: lessons for the EU. Util. Policy 38, 11–17. http://dx.doi.org/10.1016/j.jup.2015.11.005.

Bhagwat, P.C., Richstein, J.C., Chappin, E.J.L., de Vries, L.J., 2016b. The effectiveness of a strategic reserve in the presence of a high portfolio share of renewable energy sources. Util. Policy 39, 13–28. http://dx.doi.org/10.1016/j.jup.2016.01.006.

Bhagwat, P.C., Richstein, J.C., Chappin, E.J.L., Iychettira, K.K., De Vries, L.J., De Vries, L.J., 2017. Cross-border effects of capacity mechanisms in interconnected power systems. Util. Policy 46, 33–47. http://dx.doi.org/10.1016/j.jup.2017.03.005.

Borenstein, S., Bushnell, J., Kahn, E., Stoft, S., 1995. Market power in California electricity markets. Util. Policy 5, 219–236.

Bothwell, C., Hobbs, B.F., 2017. Crediting wind and solar renewables in electricity capacity markets: the effects of alternative definitions upon market efficiency. Energy J. 38.

Botterud, A., Korpas, M., Vogstad, K., Wangensteen, I., 2002. A dynamic simulation model for long-term analysis of the power market. In: 14th PSCC, Session. Sevilla, pp. 1–7.

Brown, M.A., 2001. Market failures and barriers as a basis for clean energy policies. Energy Policy 29, 1197–1207.

Bushnell, J., Flagg, M., Mansur, E., 2017. Capacity Markets at a Crossroads. Rep. to Dep. Energy, Off. Energy Policy Syst. Anal. Washington, DC.

Cazalet, E.G., Clark, C.E., Keelin, T.W., 1978. Costs and benefits of over/under capacity in electric power system planning. In: 6th Annual Illionis Energy Conference. Palo Alto, p. 106.

Cepeda, M., Finon, D., 2011. Generation capacity adequacy in interdependent electricity markets. Energy Policy 39, 3128–3143. http://dx.doi.org/10.1016/j.enpol.2011.02.063.

Cepeda, M., Finon, D., 2013. How to correct for long-term externalities of large-scale wind power development by a capacity mechanism? Energy Policy 61, 671–685. http://dx.doi.org/10.1016/j.enpol.2013.06.046.

Čepin, M., 2011. Assessment of Power System Reliability: Methods and Applications. Springer Science & Business Media.

Chao, H., Lawrence, D.J., 2009. How capacity markets address resource adequacy. In: 2009 IEEE Power & Energy Society General Meeting. IEEE, pp. 1–4. http://dx.doi.org/10.1109/PES.2009.5275173.

Chappin, E.J.L., 2011. Simulating Energy Transition. Delft University of Technology.

Chappin, E.J.L., de Vries, L.J., Richstein, J.C., Bhagwat, P., Iychettira, K., Khan, S., 2017. Simulating climate and energy policy with agent-based modelling: the Energy Modelling Laboratory (EMLab). Environ. Model. Softw. 96, 421–431. http://dx.doi.org/10.1016/j.envsoft.2017.07.009.

Cramton, P., Stoft, S., 2005. A capacity market that makes sense. Electr. J. 18, 43–54.

Cramton, P.C., Ockenfels, A., Stoft, S., 2013. Capacity market fundamentals. Econ. Energy Environ. Policy 2, 27–46.

Dahlan, N.Y., Kirschen, D.S., 2014. Generation investment evaluation model in electricity market with capacity mechanisms. Int. Rev. Electr. Eng. 9, 844–853. http://dx.doi.org/10.15866/iree.v9i4.2907.

Dam, K.H., Nikolic, I., Lukszo, Z. (Eds.), 2013. Agent-based Modelling of Socio-technical Systems. Springer Netherlands, Dordrecht. http://dx.doi.org/10.1007/978-94-007-4933-7.

De Vries, L.J., 2004. Securing the Public Interest in Electricity Generation Markets, the Myths of the Invisible Hand and the Copper Plate. Delft University of Technology.

De Vries, L.J., 2007. Generation adequacy: helping the market do its job. Util. Policy 15, 20–35.

De Vries, L.J., Chappin, E.J.L., Richstein, J.C., 2013. EMLab-generation - an Experimentation Environment for Electricity Policy Analysis (Version 1.0). Delft.

Department of Energy & Climate Change, 2012. DECC Fossil Fuel Price Projections.

De Vries, L.J., Hakvoort, R.A., 2004. The question of generation adequacy in liberalised electricity markets. SSRN Electron. J. http://dx.doi.org/10.2139/ssrn.600503.

Doorman, G., 2003. Capacity Subscription and Security of Supply in Deregulated Electricity Markets. Trondheim.

Doorman, G., Botterud, A., Wolfgang, O., 2007. A comparative analysis of capacity adequacy policies. In: Market Design Conference 2007: Incentives to Build New Generation on Competitive Electricity Markets, Stockholm, p. 12.

Ehrenmann, A., Smeers, Y., 2011. Appendix: generation capacity expansion in a risky environment: a stochastic equilibrium analysis. Oper. Res. 59, 1332–1346. http://dx.doi.org/10.1287/opre.1110.0992.

Eurelectric, 2012. Electricity capacity (power statistics 2012). URL http://www.eurelectric.org/factsfolders/DocLink.asp?DocID=72134.

Faaij, A.P.C., 2006. Bio-energy in Europe: changing technology choices. Energy Policy 34, 322–342. http://dx.doi.org/10.1016/j.enpol.2004.03.026.

Farmer, J.D.D., Foley, D., 2009. The economy needs agent-based modelling. Nature 460, 685–686. http://dx.doi.org/10.1038/460685a.

Finon, D., 2013. Can We Reconcile Different Capacity Adequacy Policies with an Integrated Electricity Market? Paris Dauphine University, Paris.

Hach, D., Chyong, C.K., Spinler, S., 2015. Capacity market design options: a dynamic capacity investment model and a GB case study. Faculty of Economics, University of Cambridge.

Hancher, L., de Houteclocque, A., Sadowska, M., 2015. Capacity Mechanisms in EU Energy Markets: Law, Policy, and Economics. Oxford University Press, USA.

Harvey, S., 2005. ICAP Systems in the Northeast: Trends and Lessons.

Helbing, D., 2012. Social Self-organization: Agent-based Simulations and Experiments to Study Emergent Social Behavior. Springer.

Hobbs, B.F., Iñón, J., Stoft, S.E., 2001. Installed capacity requirements and price caps. Electr. J. 14, 23–34. http://dx.doi.org/10.1016/S1040-6190(01)00212-3.

Hobbs, B.F., Hu, M.-C., Inon, J.G., Stoft, S.E., Bhavaraju, M.P., 2007. A dynamic analysis of a demand curve-based capacity market proposal: the PJM reliability pricing model. In: IEEE Transactions on Power Systems, pp. 3–14. http://dx.doi.org/10.1109/TPWRS.2006.887954.

Höschle, H., Doorman, G., 2016. Capacity mechanisms: results from a world wide survey. In: Proceedings of CIGRE Session 2016. CIGRE, pp. 1–9.

Höschle, H., De Jonghe, C., Le Cadre, H., Belmans, R., 2017. Electricity Markets for Energy, Flexibility and Availability – Impact of Capacity Mechanisms on the Remuneration of Generation Technologies.

IEA, 2011. World Energy Outlook 2011 (Paris).

Joskow, P.L., 2006. Competitive electricity markets and investment in new generating capacity. In: Helm, D. (Ed.), The New Energy Paradigm. Oxford University Press.

Joskow, P.L., 2008. Capacity payments in imperfect electricity markets: need and design. Util. Policy 16, 159–170.

Leahy, E., Tol, R.S.J., 2011. An estimate of the value of lost load for Ireland. Energy Policy 39, 1514–1520.

Linares, P., Rey, L., 2013. The costs of electricity interruptions in Spain. Are we sending the right signals? Energy Policy 61, 751–760.

Mastropietro, P., Rodilla, P., Batlle, C., 2015. National capacity mechanisms in the European internal energy market: opening the doors to neighbours. Energy Policy 82, 38–47. http://dx.doi.org/10.1016/j.enpol.2015.03.004.

Mastropietro, P., Herrero, I., Rodilla, P., Batlle, C., 2016. A model-based analysis on the impact of explicit penalty schemes in capacity mechanisms. Appl. Energy 168, 406–417. http://dx.doi.org/10.1016/j.apenergy.2016.01.108.

Meyer, R., Gore, O., 2015. Cross-border effects of capacity mechanisms: do uncoordinated market design changes contradict the goals of the European market integration? Energy Econ. 51, 9–20. http://dx.doi.org/10.1016/j.eneco.2015.06.011.

Moghanjooghi, H.A., 2016. Model-based Analysis of Generation Resource Adequacy in Energy-only Markets. Vienna University of Technology.

Newell, S., Bhattacharyya, A., Madjarov, K., 2009. Cost- Benefit Analysis of Replacing the NYISOs Existing ICAP Market with a Forward Capacity Market.

NREAP, 2010. National Renewable Energy Action Plan for Germany.

NYISO, 2014. NYISO - Frequently Asked Questions [WWW Document]. URLhttp://www.nyiso.com/public/markets_operations-services-customer_support-faq-index.jsp. . (Accessed 18 September 2015).

NYISO, 2013a. NYISO Installed Capacity Manual. Rensselaer, NY.

NYISO, 2013b. About NYISO [WWW Document]. URL. http://www.nyiso.com/public/about nyiso/understanding the markets/capacity market/index.jsp.

Pachauri, S., Zerriffi, H., Foell, W., Spreng, D., Praktiknjo, A.J., Hähnel, A., Erdmann, G., 2011. Assessing energy supply security: outage costs in private households. Energy Policy 39, 7825–7833.

Pérez-Arriaga, I.J., 2001. Long-term reliability of generation in competitive wholesale markets: a critical review of issues and alternative options, 2006-08-11. http://www.iit.upcomillas.es/docs/.

Petitet, M., Finon, D., Janssen, T., 2017. Capacity adequacy in power markets facing energy transition: a comparison of scarcity pricing and capacity mechanism. Energy Policy 103, 30–46. http://dx.doi.org/10.1016/j.enpol.2016.12.032.

Pfeifenberger, J., Spees, K., Schumacher, A., 2009. A Comparison of PJM's RPM with Alternative Energy and Capacity Market Designs.

Richstein, J.C., Chappin, E.J.L., de Vries, L.J., 2014. Cross-border electricity market effects due to price caps in an emission trading system: an agent-based approach. Energy Policy 71, 139–158. http://dx.doi.org/10.1016/j.enpol.2014.03.037.

Richstein, J.C., Chappin, É.J.L., de Vries, L.J., 2015a. Adjusting the CO2 cap to subsidised RES generation: can CO2 prices be decoupled from renewable policy? Appl. Energy 156, 693–702. http://dx.doi.org/10.1016/j.apenergy.2015.07.024.

Richstein, J.C., Chappin, É.J.L., de Vries, L.J., 2015b. The market (in-)stability reserve for EU carbon emission trading: why it might fail and how to improve it. Util. Policy 35, 1–18. http://dx.doi.org/10.1016/j.jup.2015.05.002.

Rodilla, P., Batlle, C., 2013. Security of generation supply in electricity markets. In: Pérez-Arriaga, I.J. (Ed.), Regulation of the Power Sector, Power Systems. Springer London, London. http://dx.doi.org/10.1007/978-1-4471-5034-3.

Rose, K., 2011. An Examination of RTO Capacity Markets (No. 2011–4).

Sioshansi, F.P., 2011. Competitive Electricity Markets: Design, Implementation, Performance. Elsevier.

Spees, K., Newell, S.A., Pfeifenberger, J.P., 2013. Capacity Markets - Lessons Learned from the First Decade. Econ. Energy Environ. Policy 2.

Stoft, S., 2002. Power System Economics - Designing Markets for Electricity. IEEE Press, Wiley-Interscience. Press.

Traber, T., 2017. Capacity remuneration mechanisms for reliability in the integrated european electricity market: effects on welfare and distribution through 2023.

Util. Policy 46, 1–14. http://dx.doi.org/10.1016/j.jup.2016.10.005.
Vazquez, C., Rivier, M., Perez-Arriaga, I.J.J., 2002. A market approach to long-term security of supply. IEEE Trans. Power Syst. 17, 349–357. http://dx.doi.org/10.1109/TPWRS.2002.1007903.
Weidlich, A., Veit, D., 2008. A critical survey of agent-based wholesale electricity market models. Energy Econ. 30, 1728–1759. http://dx.doi.org/10.1016/j.eneco.2008.01.003.
Wilks, M., Bloemhof, G.A., 2005. Reliability: going Dutch?. In: 3rd IEE International Conference on Reliability of Transmission and Distribution Networks, pp. 45–48.
Woo, C.-K., Lloyd, D., Tishler, A., 2003. Electricity market reform failures: UK, Norway, Alberta and California. Energy Policy 31, 1103–1115.