Resource Adequacy and Optimal Investment in Energy-only Markets

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Abstract. In this paper, a dynamic energy-only market model is proposed to study the impact of scarcity prices and demand response on the resource adequacy. The proposed market model probabilistically evaluates resource adequacy conditions by simulating the uncertainty both in the generation and demand side of the market. Regarding the uncertainty in generation side, the capacity credit of intermittent renewable and the forced outage of dispatching generators and regarding the demand side uncertainty, the impact of load forecast error and weather uncertainty are analyzed. Then, we implement a Monte Carlo analysis over a large number of scenarios with varying demand and supply conditions in order to examine a full range of potential economic and reliability outcomes. The optimal investment in new capacity is calculated by considering the expected profitability associated with all possible outcomes in future. The proposed model estimates hourly and annual production costs, market prices, profit for all producers, the frequency of scarcity events and the profitability of new installed capacities.
The results show that an energy-only market needs a combination of optimal demand response and load shedding in order to provide efficient investment in generation capacity. Results prove that there is a negative correlation between optimal load shedding period and demand response capacity. In other words, a market with high demand response capacity will have shorter period of load shedding. Besides, increasing the price cap to approach to the Value of Lost Load (VOLL) results a shorter high price period and less frequent load shedding. Also, price cap and demand response calling period have a negative correlation at the fixed demand response capacity. In other words, as much as the price cap increases in the market, the demand response calling period decreases. And, higher willingness to pay by consumers results lower probability of load shedding in the market.

Keywords: Energy-only market, Loss of load probability, Demand response, Price cap, Resource adequacy

1 Introduction

Electricity market liberalization was started around the last decade of 20th century in the several countries in Europe and US. This reform was intended to increase the role of market forces and economic decisions and consequently decrease the role of political forces. Typically, the old vertically integrated utilities were broken up to the competing generators and retailers and regulated network sector. The market liberalization was expected to bring better responsiveness of customers, high reliability in the market and more cost-reflective prices and it was successful to achieve some these goals [1].

However, Energy market are facing rapid changes which bring some new opportunities and challenges for all market participants and make it necessary to modify current market design. The combination of increasing low-carbon investment, rising peak demand and aging networks are driving higher costs to the customers in energy market. One of these rapid changes is continuous increase in electricity generation from intermittent renewables such as solar and wind. In many countries, electricity generation from renewables is taking over a relevant share of the market. The share of renewables in electricity generation in European Union is increased from 12% in 1990 to 21% in 2010. It is expected that the electricity generation share from new renewables such as wind and solar will be more increased in near future [1].

This paper is structured as follows: Following current section, the motivation and literature review on the resource adequacy are presented. In section 2, the proposed energy market model is presented and it includes the details of the modeling uncertainty of generation and demand, reliability measure and the optimal investment estimation. The case study and the main assumptions in the model are discussed in section 3. The simulation results and analysis are presented in section 4. Section 5 concludes all the main findings.

1.1 Motivation

In an energy-only market, all generators receive revenues for their electricity sales to the market. The generators have to cover their variable and fixed costs with these revenues. Moreover, all investment incentives result from the energy-based market revenues. Since the market price is determined by a uniform price auction, all generators receive the bidding price of the most costly unit in the merit order which is need to serve the current load. Hence, all generators benefit from high scarcity prices in case of peak demand as they need these inframarginal rents to recover their fixed costs. A well-functioning energy-only market should be able to provide cost recovery for all generators to ensure an adequate level of supply in the market. In the case if the scarcity prices are not high enough to sufficiently recover the fixed cost of marginal bidding technology, the market will face underinvestment in generation capacity. Insufficient investment incentives in energy market leads to the resource adequacy or supply security problem.

There are three main reasons which results resource adequacy problem in energy-only market design. First, resource adequacy problem may occur as a direct result of political or regulatory price interventions. Regulators or policy makers implement a bid cap or price cap on the market prices, in order to prevent the market power abuse. The side effect of this policy is that it may suppress real scarcity prices, and hence, the market fails to incentivize new investments.

Second, resource adequacy problem could occur as a result of increasing investment risks. The cost recovery of marginal producers totally depends on the scarcity prices which may be limited to few hours in each year. Also, electricity supply industry recently faces significant external market risks caused by uncertain changes of future regulation and market design. Hence, the high risk of unfavorable market interventions makes the investors more uncertain about the profitability of new investment in future.

Third,the integration of large amounts of renewables into the electricity market is another driver which exacerbate the resource adequacy problem. The reason is that increasing share of renewables with very low marginal cost leads to the merit order effect which denotes the rightward shift of conventional generators in the supply curve and three related effects can be observed. The first effect is the reduction in the utilization of all conventional generators decreases. The profitability reduction of the peak and medium-load power plants is relatively stronger through a significant reduction of both their utilization time and generated electricity. The second effect is the reduction of both the average electricity prices and the frequency of scarcity prices. This effect leads to a significant reduction of inframarginal rent for all generators. As the base and medium-load generators have higher investment costs, they are more vulnerable to the lower average prices which result less inframarginal rent for these generators. A permanent lack of these inframarginal rents lowers the investment incentives and may endanger generation adequacy in the long run. The third effect of the renewables introduction is that the dominance of intermittent renewables capacity in the market increases the variability of generation profile. Hence, market needs a sufficient amounts of reliable backup capacity, i.e. conventional generators, to accommodate for the risks of volatile renewables' supply. Even though the share of conventional generation capacity is decreasing, but the investment incentive for these plants plays an essential role for resource adequacy in a renewable-dominated market.

1.2 Literature review

In [2], which is one of the first studies in resource adequacy, it is mentioned that the combination of construction lags, lumpy plant entry and the investment and regulatory uncertainties make the generation investments unusually risky. Also, the first contributions that described the difficulty of investment in peaking plant in energy-only markets were [3] and [4]. A theoretical analysis about resource adequacy and insufficient investment in energy markets is presented in [5], [6]. In these studies, it is mentioned that the current market structure may not be able to provide sufficient incentives for new investment in the conventional generation.

Regarding the resource adequacy in energy-only market structure, demand response plays an essential role to achieve an effective competition in the energy market. The participation of consumers in the market provides an elastic demand and change the consumption pattern during reduced availability of backup capacity in the market which could mitigate the resource adequacy problem. The scarcity prices are essential in addressing resource adequacy problem and any deviation from efficient scarcity prices will result less investment in new capacity [7].

As high market prices could result from scarcity situation or abuse of the market power by some of generators, market administrators usually implement a price cap in the market to protect consumers. ERCOT (Electric Reliability Council of Texas) is an example of a market which uses energy-only resource adequacy mechanism. The purpose in this market is to elicit the true willingness to pay for electricity by customers. In ERCOT, to enhance the effectiveness of the energy-only resource adequacy mechanism, market operator decided to increase biding price cap from 4.5 $/KWh in 2012 to 9 $/KWh in 2015 [8].

In an optimal competitive electricity market, the market price should allow all the producers to recover their fixed and variable costs of generation. There is an evolving interest in whether wholesale electricity market should include a capacity market in addition to an energy market or not [9]. Among capacity mechanisms, capacity credit mechanism and reliability options are used when a separate capacity market is established in addition to the energy-only market. Capacity payments and strategic reserves are two other mechanisms which are implemented in energy-only market. Capacity payments are determined by market administrator and are dependent on the available capacity and the reserve margin in the market. Higher excess capacity in the market means lower capacity payments. In the strategic reserves mechanism, an auction is held on a certain amount of capacity which is withdrawn from regular energy market [10]. The effectiveness of these capacity mechanisms are investigated in different studies [11], [12], [13]. While most of these capacity mechanisms work well in an ideal environment, they differ with respect to their resilience against market imperfections such as risk-averse behavior by investors or insufficient information about demand growth [13]. Different studies have been done to find the true willingness to pay for electricity by estimating the Value of Lost Load (VOLL). In [14], a macroeconomic model is proposed to estimate outage costs in Germany by analyzing the VOLL for different consumers. It estimates that VOLL is 6 €/KWh for commercial and industrial consumers and 15.70 €/KWh for household consumers. The weighted average of blackout costs in Germany is estimated to be 8.51 €/ KWh.

2 Energy-only market Model

In this study, the main focus is on the energy-only market and how this market design could mitigate the resource adequacy problem. To this aim, we define two major components in an energy-only market which addresses the resource adequacy: scarcity prices and demand-side participation. First, we believe that the shortfall of investment may occur as a direct result of political or regulatory price intervention. High scarcity prices are economically a signal to attract new investment to restore efficient market equilibrium. Currently, regulators and policymakers implement a price cap or bid cap on the market to protect consumers from extreme price spikes. The price cap may suppress real scarcity prices and hence, the market fails to incentivize new investment. In our proposed model, we focus on the scarcity prices and the probability of happening high prices, which is an important component of energy-only markets addressing the resource adequacy problem. The second component is integration of the demand response (DR) to the energy-only market. DR increases the market flexibility by enhancing the responsiveness of the electricity demand to the market prices. We believe that demand response alleviate the resource adequacy problem in an energy-only market by reducing the need for conventional backup capacities.

In this paper, we model an energy-only market with scarcity prices and demand response and study how this market design could mitigate the resource adequacy problem. To this aim, we propose a probabilistic framework to evaluate resource adequacy conditions based on the generation and load uncertainty and reliability analysis. The proposed framework evaluates the uncertainty in both generation and demand side of the market regarding the resource adequacy. Then, reliability is measured based on the generation and demand probability distribution functions and the optimal investment is decided based on the reliability measures. These components of the energy market framework are discussed in the following.

2.1 Generation uncertainty

Market operators are responsible for the long term resource adequacy in electricity markets. To have a reliable market, they take into account the fluctuations of supply and demand side such as planned or unplanned outage and retirement of the power plants, volatile generation by variable renewables. All generators with different generation technologies contribute to the generation system adequacy in different levels. Dispatching generators have a higher contribution to the resource adequacy, as the probability of planned or unplanned outage for these generators is low. In this section, we want to model the main uncertainties in the generation side of the market, which address to the resource adequacy problem. So, we consider two main sources of uncertainties including capacity credit of renewables and the forced outage of conventional generation.

Capacity credit of renewables In this section, we want to analyze the uncertainty of the electricity generation by intermittent renewables and its impact on the resource adequacy. Compared to the dispatching generators, intermittent renewables have less contribution to the resource adequacy, as the correlation of renewables production and peak demand is much less than the correlation of available dispatching generation and peak load. Actually, in presence of intermittent renewables, electricity market requires additional back up capacity to maintain the target reliability level of the electricity system. The key question is that in presence of specific intermittent renewable capacity, how much of dispatching back up capacity is required to maintain system reliability.

In the proposed approach, we use the hourly electricity generation by wind and solar in Germany in 2012. The capacity factor and capacity credit of the intermittent renewables is calculated by considering the correlation between solar and wind generation and electricity demand. The hourly capacity factor of a power plant is the ratio of its actual generation to its nominal generation for each hour. The Probability Distribution Function (PDF) of the hourly PV and wind generation capacity factor in Germany in 2012 is depicted in Fig1. The minimum, maximum and mean values of PV capacity factor are 0, 0.64 and 0.09 and these values for wind capacity factor are 0, 0.63, and 0.13.

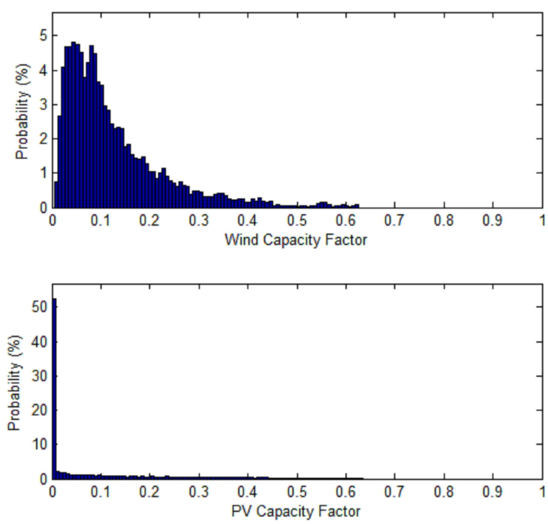

Fig. 1. Wind and PV capacity factor

Capacity credit, or capacity value, of a power plant is the amount of additional peak load that can be served due to the addition of a new generation capacity, while maintaining the existing level of reliability [15]. The Intermittent renewables have much lower capacity credit levels than conventional generators. Capacity credit depends on several parameters such as the average load factor and the correlation between generation and peak demand. The capacity credit of wind and PV is calculated using several statistical methods in [15], [16], [17] and [18]. In the proposed approach, which is based on the capacity credit calculation approach in [18], the capacity credit of variable renewables is defined as the difference between the peak load and peak residual load in each year. Fig2 illustrates the capacity credit of variable renewables as a difference between peak load and peak residual load.

The procedure is described in the following: First, the hourly wind and PV generation and hourly load values are clustered, which is shown in Fig3. The high and low values of each data set are determined by comparing to the mean value of the data set.

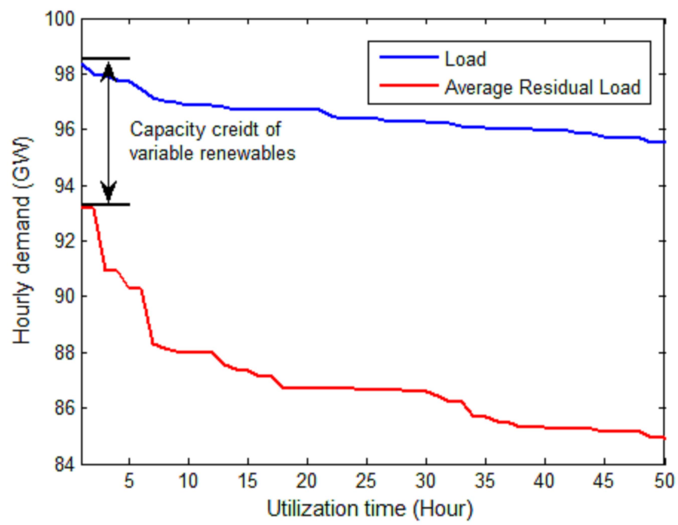

Fig. 2. Capacity credit of renewables

Second, the histogram of the data set for each cluster is determined. The histograms of the wind and PV generation in low and high demand are depicted in Fig4 and Fig5. These histograms for the future years are scaled by the installed capacity of PV and wind and the demand growth for each year. The hourly renewable generation and load values for each year are determined by sampling from the relevant histograms.

Third, we run 100 independent Monte Carlo samples of wind and PV generation and load values for the whole simulation period. These samples are taken from the mutual histogram of wind and PV generation and load. The capacity credit is calculated as the difference between the average of 10 highest load hours and 10 highest residual load values. By analyzing the Monte Carlo samples, it is concluded that a normal distribution fits to the annual capacity credit of renewables. The capacity credit of variable renewables in each year is depicted in Fig6. The mean value of annual capacity credits are shown with the red line. Also, Fig7 shows that the ratio of capacity credit to the installed capacity of variable renewables decreases with the penetration level. Also, the capacity credit

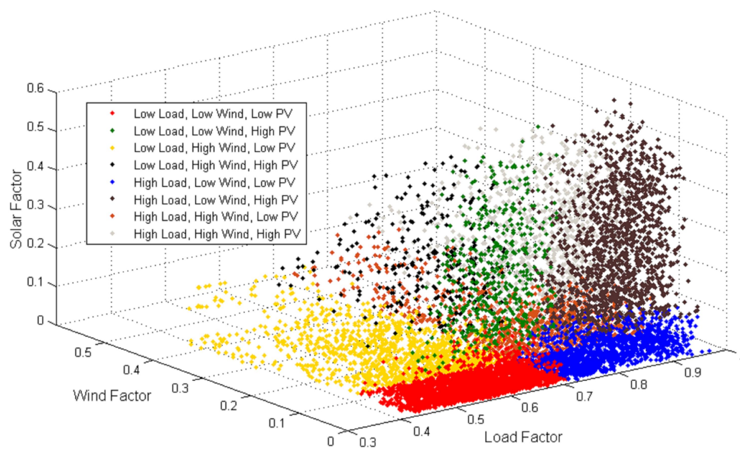

Fig. 3. Load, wind and solar factor data clustering

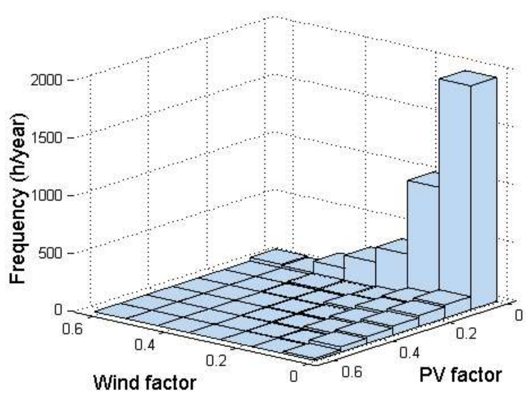

Fig. 4. Wind-PV generation histogram in low demand

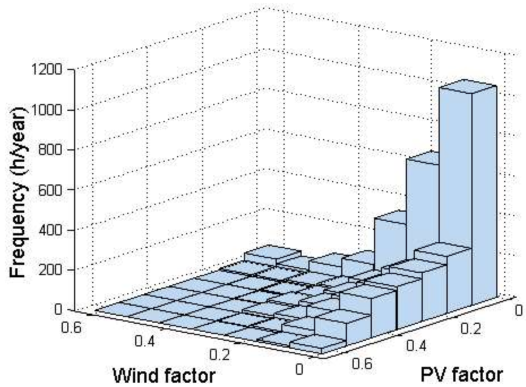

Fig. 5. Wind-PV generation histogram in high demand

of renewables is in the range of 2% to 4% of total installed capacity, which in comparably lower than the both the average capacity factor of PV and wind which are 9% and 13%.

Forced outage of conventional generation Another major component of generation uncertainty in resource adequacy analysis is the forced outages by dispatching generation. There are two type of outages which could happen in dispatching generators: planned outage and forced outages. The planned outages could be postponed and usually scheduled during low demand periods in the spring and fall. As the reliability analysis for resource adequacy is mainly crucial during peak hours, the forced outages are only considered in our model. Forced outage is a full or partial outage of a generation unit which cannot not delayed for a reasonable threshold, e.g. 48 hours. We model forced outages of dispatching generation units stochastically, with partial and full forced outages occurring based on the probability distribution function of forced outages. We calculate the distribution of the annual outage by using the duration and the amount of forced outage in German electricity market in 2012. The histogram of the forced outages is depicted in Fig8.

2.2 Load uncertainty

In this section, we model the main uncertainties in the load side of the market, which address to the resource adequacy problem. So, we consider two main sources of uncertainties including weather uncertainty and load forecast error uncertainty.

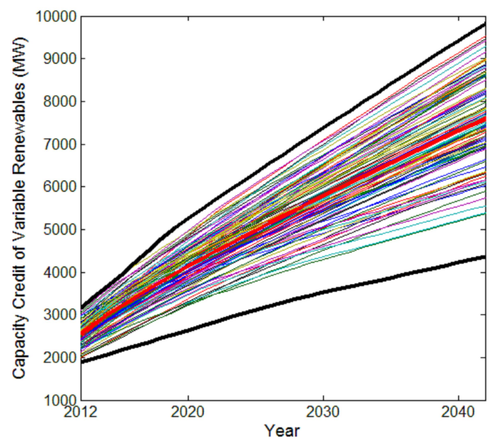

Fig. 6. Monte Carlo samples for capacity credit of renewables

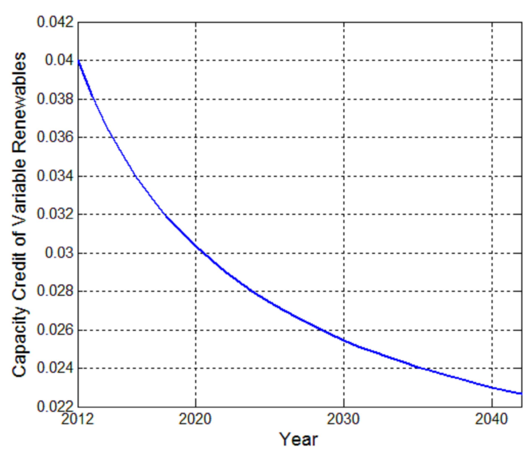

Fig. 7. capacity credit

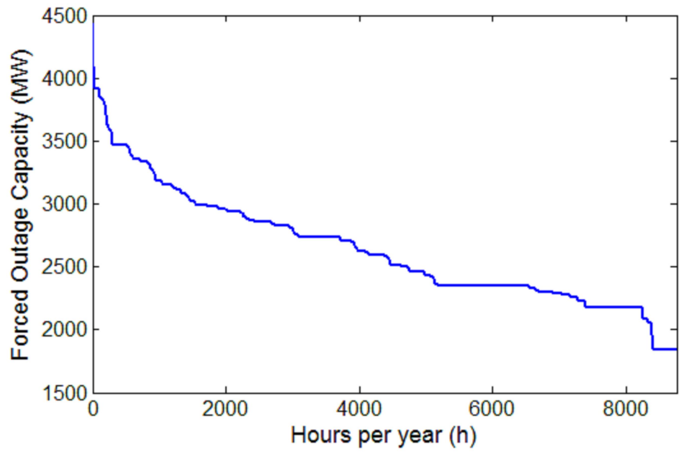

Fig. 8. forced outage

Load forecast error uncertainty In this study, the load forecast errors are separated from weather-related uncertainties because load forecast error is dependent to the forward planning period and it increases with the planning period, while weather uncertainty is independent with the forward period. The load forecast error sources are generally the uncertainties in population growth, economic growth, efficiency rates, and other factors. We assume that a non-weather load forecast error is normally distributed with mean zero and a standard deviation σ_f of 0.8% on a 1-year forward basis, increasing by 0.6% with each additional year. We assume investment decisions must be finalized three years prior to delivery, consistent with the approximate construction lead time for new generation resources.

Weather uncertainty The load uncertainty by weather condition is commonly assumed to be normally distributed with mean zero and a given standard deviation σ_w. The standard deviation is assumed to be 2% of percent of the peak load in each year. Based on the distribution, the extreme weather conditions will be less likely.

The load uncertainty which is the sum of both weather and forecast error uncertainties is given in equation (1). D is the real values of demand by considering the uncertainty and m_D is the mean values of forecasted demand.

$$D \sim N(0, \sigma_w) + N(m_D, \sigma_f) = N(m_D, \sqrt{\sigma_w^2 + \sigma_f^2}) \tag{1}$$

2.3 Demand response

Demand response (DR) is the change in electricity demand by end-use customers from their normal consumption patterns in response to changes in the price of electricity over time. Increasing DR penetration results the increase in supply curve and energy prices, because low cost generation resources will be displaced by higher cost DR. In this paper, DR is modeled as it is available over a wide range of dispatch prices, beginning from highest bidding cost of marginal producer in the market up to the price cap. A typical supply curve with effective generation for all producers and demand response in German electricity market in 2012 is depicted in Fig 9.

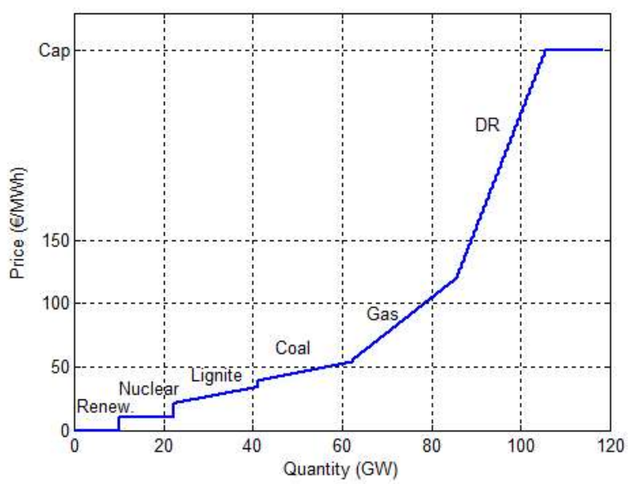

Fig. 9. Merit order curve, Germany, 2012

2.4 Optimal investment

In this section, we define the general problem of optimal generation investment. Considering the uncertainty in the generation and demand side of the electricity market, the state of the system is defined by s which captures all uncertainties of the random variables in the model. For each generator type i, the utility function U_i, cost function C_i, generation rate (Q_i), installed capacity K_i, constant variable cost c_i and fixed cost f_i are represented. The cost function is defined in equation (2).

$$C_i(Q_i, K_i) = c_i Q_i + f_i K_i \tag{2}$$

The social welfare optimization problem is defined in equation (3) and the constraints are given in equation (4) and (5). The constraints specify that the generation of each generator is limited between zero and the full load generation capacity of that generator.

$$\max \sum_s p_s \left(U_s \left(\sum_i Q_{is} \right) - \sum_i C_i(Q_i, K_i) \right) \tag{3}$$

subject to:

$$Q_{is} \leq k_i \quad (\alpha_{is}) \tag{4}$$

$$Q_{is} \geq 0 \quad (\beta_{is}) \tag{5}$$

The KKT conditions of the optimization problem results the following equations (6) to (9).

$$\forall i, s : \alpha_{is} - \beta_{is} = U_s'(Q_{is}) - c_i \tag{6}$$

$$\forall i, s : \sum_s p_s \alpha_{is} = f_t \tag{7}$$

$$\forall i, s : \alpha_{is} \geq 0 \;\; \& \;\; \alpha_{is}(K_t - Q_{is}) = 0 \tag{8}$$

$$\forall i, s : \beta_{is} \geq 0 \;\; \& \;\; \beta_{is} Q_{is} = 0 \tag{9}$$

The KKT conditions show that the optimal dispatch has the property that if the generation rate of generator type i is greater than zero and less than the total capacity of that generator (i.e. $Q_{is} > 0$ & $Q_{is} < K_i$), the rate of the production is equal to the variable cost of (i.e. $U_s'(Q_{is}) = c_i$). When the rate of production for the generator type i is equal to its installed capacity (i.e. $Q_{is} = K_i$), the price could be above the marginal cost of generator type i. The KKT condition results the equation (10) and it states that the level of investment in new installed capacity of a given type is optimal when the difference between average prices and variable cost of each generator is equal to the per unit fixed cost of new additional capacity.

$$\sum_s p_s \alpha_{is} = \sum_{s:P_s>c_i} p_s(P_s - c_i) = E((P-c_i)|(P>c_i))Pr(P \geq c_i) = f_i$$

$$\Longrightarrow E(P|P>c_i) = c_i + \frac{f_i}{Pr(P>c_i)} \quad (10)$$

The contribution margin for each generator is given in equation (11). In a competitive energy-only market with a free-entry and free-exit equilibrium, the expected profitability of new investment will be zero (i.e. $E(\pi_i) = 0$). In other words, the expected price given that the price is higher than variable cost of that generation type must be equal to the variable cost plus the per unit fixed cost discounted by the probability that the price is above the variable cost.

$$E(\pi_i) = \left(E(P|P>c_i) - c_i - \frac{f_i}{Pr(P>c_i)} \right) K_i \quad (11)$$

2.5 Simulation algorithm

The investment in the proposed energy-only market is done in the following sequence:
Step I: calculate the hourly price and profit values for all generators in year i.
Step II: Find S_i which is the optimal new investment in year i (by estimating the expected profitability of new investment in future).
Step III: Add S_i to the installed capacity in year i+delay (delay is the construction time of new installed capacity)
Step IV: i=i+1 and go to the Step I.

3 Case study

In this paper, the case study is the German energy-only market with a perfect competition. This market is analyzed form 2012 to 2042 by considering the increasing share of solar and wind generation up to 50% of total electricity consumption in the last year. As mentioned in the previous section, the uncertainty is considered in both generation and demand. We will maintain the following assumptions: The investors or entrepreneurs have complete information about all players in the market and they decide to invest if and only if it is profitable. Capacity can be added in arbitrary small increments and there is no limit on the volume of new additional capacity. It is assumed that investors choose to invest if and only if they expect that new investment will be profitable.

We assume that a new installed capacity will be in the form of intermittent renewables and gas-fired power plants. New installed capacity in solar and wind will be added linearly each year, up to the 50% of total consumption in the last simulation year. We assume that gas-fired power plant is the only choice for investors to construct as new installed capacity. There are two reasons for this assumption: The first reason is that gas-fired power plants have less investment costs compared to the other conventional generators. As the number of utilization hours for the peaking technology is limited, the less capital intensive technology is more suitable choice for new investment. Second reason is that increasing share of intermittent renewables will result more fleet-wide variability in generation profile. The backup capacity should be able to respond very fast to the variable generation profile. Hence, the gas-fired plants are better choice for back up capacity among other dispatching generators, as they have a quick start up and ramp up its load very quickly in a matter of minutes. The construction time for new gas plants is assumed to be 3 years. It means that whenever the investors decide to invest on new plant, it will take 3 years that the new capacity become available in the market.

4 Simulation results and analysis

4.1 Scenario I: Overcapacity and demand response

In this scenario, we want to analyze the impact of initial overcapacity and the impact of demand response on the resource adequacy in the German electricity market. It is assumed that the total installed capacity in 2012 is 105% of peak demand in that year and the overcapacity is almost 4 GW. This overcapacity is totally effective capacity which means that it could be dispatched during whole year. The demand response capacity is modeled as following: from 2012 to 2021 (first 10 years of simulation period), there is no demand response. From 2022 to 2031, available demand response capacity is equal to the 2% of peak demand in each year. And from 2032 to 2042, the available demand response capacity is increased to 4% of peak demand in each year.

The distribution of the profitability of gas plants under different uncertainty scenarios is shown in Fig 10. The initial overcapacity in the market results a negative profit (or loss) for the gas plants and it causes a delay for investment in new installed capacity. Results show that from 2018 (7^{th} simulation year) the average profit of gas plants becomes positive and investors decide to invest on new installed capacity. As it is shown, in the case if the correlation between renewables and peak load becomes higher than expectations and demand growth rate becomes less than expectations, the gas plants could be unprofitable. The results show that by excluding the impact of overcapacity, the weighted average profit of gas plants over all uncertainty scenarios is always positive.

The annual load shedding and demand response utilization period are shown in Fig 11 and Fig12. The initial overcapacity in the market postpones the load shedding in some of the uncertainty scenarios. The average load shedding period rises up to 13 hours in 2021. In 2022, a demand response equal to 2% of peak demand in each year becomes available in the market. From this year, the average annual load shedding period drops to 7 hours per year and the average period of demand response increases up to 14 hours per year. Again in 2032, the demand response capacity increases to the 4% of peak demand in each year.

Hence, the average annual load shedding period decreases to 4 hours and average annual demand response utilization period increases to 24 hours. The reason is that introducing the demand response to the market with high marginal price provides high inframarginal rent for new installed capacities to recover a big portion of their fixed costs during demand response calling period and the required load shedding period decreases. Also, the results show that the load shedding could occur in longer periods during the worst case scenario (extreme weather condition or less capacity credit of renewables), but these scenarios are less likely.

Fig 13 illustrates spot energy market price volatility by comparing annual price duration curves in different generation and demand uncertainty scenarios for a specific year. The price duration curve derived by weighted average across all uncertainty scenarios are depicted with black circles. The worst case scenario is when the uncertainty with highest generation and load uncertainty occurs in a specific year. Results show that on average, spot energy prices would rise to the level of price cap only one hour per year, while prices would rise to price cap level in approximately 13 hours per year under worst case scenario.

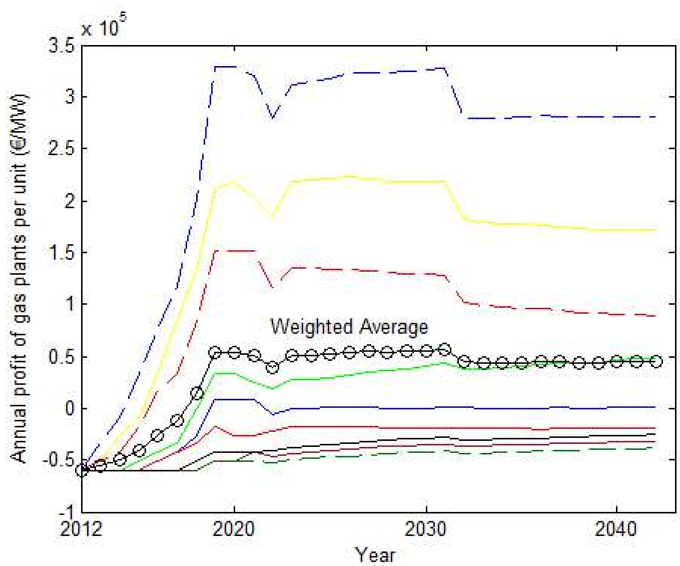

Fig. 10. Annual profit of gas plants per unit (€/MW)

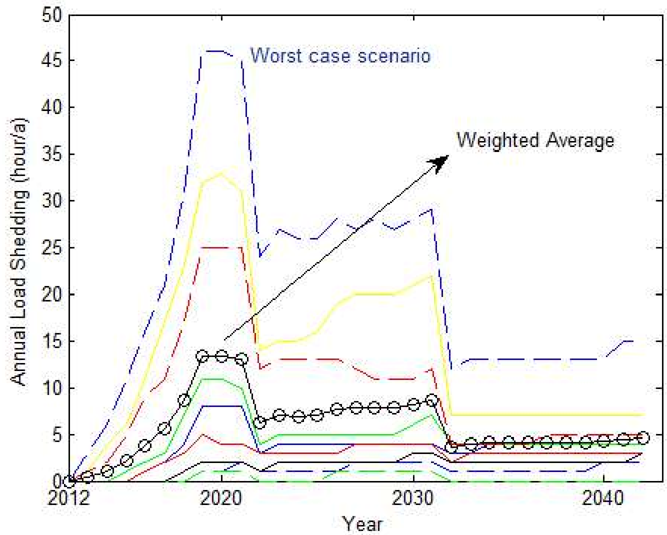

Fig. 11. Annual load shedding period (hour/year)

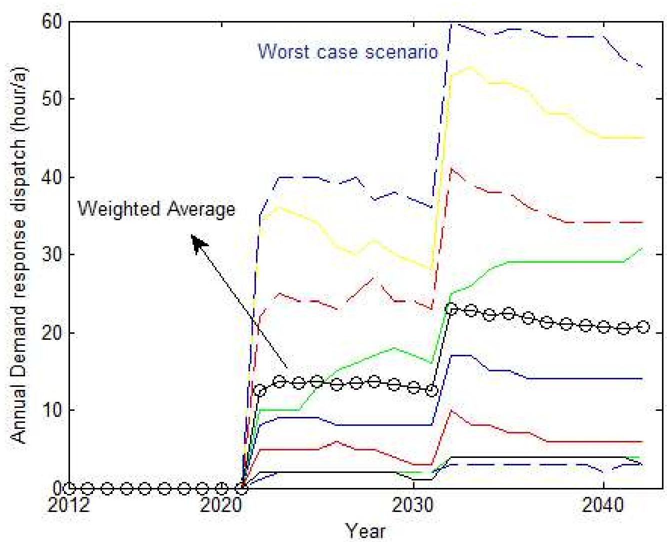

Fig. 12. Annual demand response call period (hour/year)

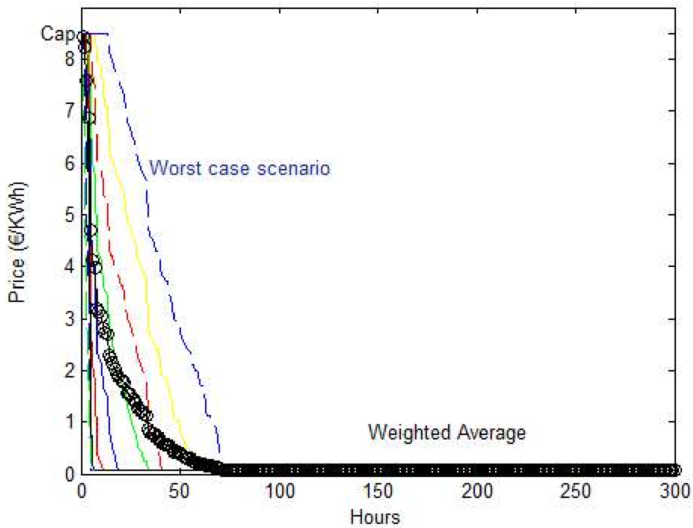

Fig. 13. Price duration curve

4.2 Scenario II: Price cap

In this scenario, we want to analyze the impact of demand response and price cap level on the LOLP, the frequency of scarcity events and the profitability of marginal producers i.e. gas turbines. To this aim, two market designs are defined. The first market is designed with a price cap equal to 3 €/KWh, which is the current price cap in the European Power Exchange (EEX) that covers the German energy market. The second market is designed without any price cap and the prices could reach up to the Value of Lost Load (VOLL), which is the highest bidding price by consumers. The average VOLL in German energy market is assumed to be 8.5 €/KWh.

The variation of LOLP and market price for two different price caps and in the 50 highest-LOLP hours in year 2037 and in a random uncertainty scenario is depicted in Fig 14. As expected, the average market price is decreasing when the LOLP decreases. The results show that in the market with higher price cap, the duration of high prices and the duration of high LOLP are shorter than the case of the same market with lower price cap. Also, it proves that the optimal duration of load shedding is dependent on the price cap level. It means that by increasing the level of price cap, the optimal duration of load shedding is decreasing. For instance, in the current level of price cap, the optimal load shedding period in year 2037 is 15 hours. But, if the market operator sets the price cap up to the level of the VOLL, the optimal duration of load shedding is decreased to 3 hours in that year. So, the optimal load shedding frequency and the level of price cap have a negative correlation with each other.

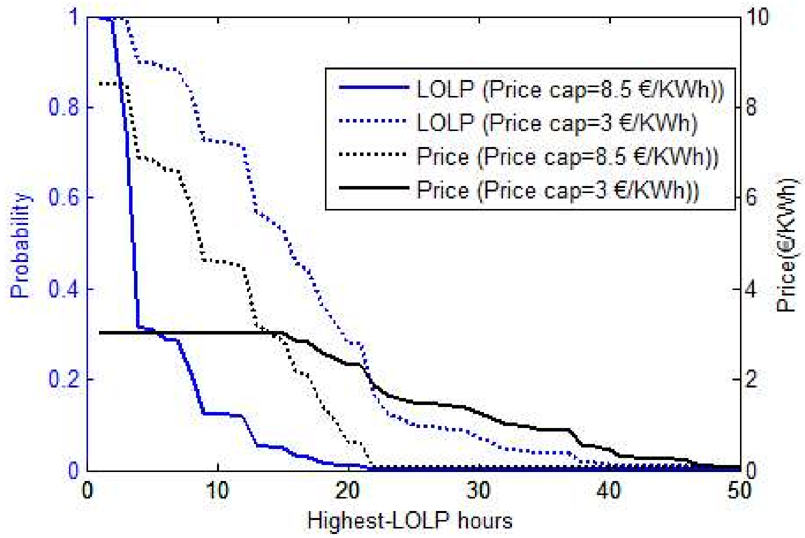

Fig. 14. Price duration curve

Also, Fig 14 shows that the average demand response utilization period at the same demand response capacity is dependent to the price cap. It means that the higher price cap results lower average utilization period for demand response capacity. The reason is that the higher price cap leads to higher revenue for new capacity and higher new installed capacity compared to the lower price cap scenarios. Therefore, in the market with higher installed capacity, the probability of the utilization of interruptible loads is lower. Thus, at the same demand response capacity, the price cap and utilization hour for demand response have a negative correlation with each other.

5 Conclusions

This paper analyzes the resource adequacy in German energy-only market by considering the scarcity prices and demand response in a probabilistic framework. The proposed model evaluates the resource adequacy conditions by simulating the capacity credit of renewables, conventional generation outage and weather and load forecast uncertainty. Monte Carlo analysis is utilized to properly capture the magnitude and the impact of reliability conditions during extreme events. Then, the hourly and annual prices and profits for all generators, frequency of scarcity events and profitability of new installed capacities are evaluated in the proposed dynamic market model. The investors make the investment decisions on new installed capacity by estimating the expected profitability of new investment during its life time. Our analyses represent the expected long-term condition in the German energy-only market when generators are earning adequate returns on average to cover their total costs and there is an incentive for investment in new generation.

The main findings are mentioned in the following. First, in an energy-only market, as long as there is a fixed cost of holding extra capacity, it is not efficient to increase the installed capacity to the level of 100% reliability. Second, higher value of consumption to consumers (higher VOLL) results lower probability of load shedding. Third, the optimal load shedding period and the amount of demand response capacity have a negative correlation with each other. It means that a market with high demand response capacity will have shorter period of load shedding. Fourth, the high price and high LOLP period in energy-only market are dependent to the price cap. It means that higher price cap results shorter high price period and less frequent load shedding. Fifth, at the same demand response capacity, the price cap and demand response utilization period have a negative correlation with each other. In other words, as much as the price cap increases in the market, the demand response calling period decreases.

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