DISSERTATION

Model-based Analysis of Generation Resource Adequacy in Energy-only Markets

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Abstract

Electricity is an undifferentiated commodity with a limited storage capability, low demand elasticity and wide seasonal variations. All producers with a wide range of generation technologies have to bid based on their short-term marginal cost at the electricity market, which makes it particularly difficult for most expensive producers such gas-fired power plants to recover their capital costs. This issue causes fewer incentives for investment in new capacity, which in turn leads to a resource adequacy problem. The literature specifies two main reasons for this problem. First, political and regulatory interventions such as price caps and a limited duration of scarcity prices result in a high risk of investment in new generation capacity. Second, the increasing share of variable renewable (RES) with very low marginal costs leads to lower load factors and less revenue for conventional generators, lower average prices and less frequent scarcity prices, and finally, more need for backup capacity to mitigate their intermittent nature. The main question this study is meant to answer is how an energy-only market (EOM) design can ensure the long-term resource adequacy in the German electricity market. Following the main research question, this study addresses policy and practical implications of EOM by evaluating the impact of investment risk, demand response (DR) and price caps on the long-term generation adequacy and estimating an economically optimal reserve margin.

In this study, a probabilistic framework is proposed to evaluate the long-term dynamics of generation capacity expansion from both economic and reliability aspects. The proposed model evaluates resource adequacy by estimating the probability distributions of generation availability and load uncertainty. A Monte Carlo analysis over a large number of scenarios with varying demand and supply conditions is implemented in order to examine a full range of potential economic and reliability outcomes. Then, a stochastic optimization framework is proposed to find the risk-neutral and risk-averse investment in new generation capacity by estimating the expected profitability of new capacity during its lifetime.

The obtained results represent the expected long-term resource adequacy condition in the German EOM. The risk-neutral economically optimal reserve margin in this market is estimated at 6.5% of peak load. Therefore, an EOM with reserve margin of 6.5% will ensure the long-term resource adequacy in Germany. However, if policymakers have strong risk-averse preferences and do not

tolerate any low-probability load shedding events, the mandatory reserve margin will be higher than the optimal one. Findings prove that the derivative of total generation expansion costs around the optimal reserve margin is low and an increase in the reserve margin from 6.5% to 8% would result in a mere 7% increase in annual expansion costs (approximately 26 million €/year). This additional cost can be interpreted as the cost of implementing a capacity mechanism such as strategic reserves by using existing or new combined-cycle gas-turbine (CCGT) plants.

Results show that in presence of the optimal reserve margin and 20% share of variable RES in the German market, the total annual DR call is 29 hours, the maximum DR call per day is 5 hours and the maximum amount of energy provided by DR per day is 1,760 MWh/day. This means that any restriction on DR dispatch which is lower than these values will result in a resource adequacy value of less than 100% for DR. The amount of the economically optimal DR capacity to ensure resource adequacy depends on five main factors: installed generation capacity, DR penetration level, DR dispatch price and fixed cost, price cap, and the share of variable RES in the market. By increasing the share of variable RES from 30% to 50%, the average optimal volume of economic DR capacity increases from 5 GW to 10 GW. In the presence of 50% generation from variable RES, the average optimal capacity of emergency DR with the dispatch price of 500 €/MWh amounts to 15 GW with the DR call period of 135 hours.

Kurzfassung

Elektrizität ist eine undifferenzierte Ware mit begrenzter Lagerfähigkeit, geringer Nachfrageelastizität und starken saisonalen Schwankungen. Alle Energieerzeuger müssen ungeachtet der zugrundeliegenden Erzeugungstechnologien auf Basis ihrer kurzfristigen Grenzkosten auf dem Strommarkt bieten, was es für die teuersten Produzenten (z.B. Gaskraftwerkbetreiber) besonders schwierig macht ihre Kapitalkosten wiederzuerlangen. Dies führt dazu, dass weniger Anreize für Investitionen in neue Kapazitäten vorhanden sind, was wiederum zu einem Problem im Sinne der Ressourcenadäquanz führt. In der Fachliteratur werden zwei Hauptgründe für das Problem der Ressourcenadäquanz in Elektrizitätsmärkten genannt. Erstens, politische und regulatorische Interventionen (z.B. Preisobergrenzen, zeitlich begrenzte Perioden mit Mangelwarenpreisen) führen zu einem hohen Risiko für Investitionen in neue Erzeugungskapazitäten. Zweitens, der zunehmende Anteil von erneuerbaren Energieerzeugung (renewable energy resources, RES) mit sehr niedrigen Grenzkosten führt zu niedrigeren Belastungsfaktoren und weniger Einkommen für konventionelle Erzeuger, niedrigere Durchschnittspreise und weniger häufige Mangelwarenpreise und schließlich mehr Bedarf an Backup-Kapazitäten, um Diskontinuitäten in der Erzeugen ausgleichen zu können. Die wichtigste Frage, die diese Studie beantworten soll, ist, wie ein rein energiebasiertes Marktdesign (energy-only market, EOM) die langfristige Ressourcenadäquanz auf dem deutschen Strommarkt sicherstellen kann. Im Anschluss an die Hauptforschungsfrage befasst sich diese Studie mit den politischen und praktischen Auswirkungen solcher Energiemärkte, indem sie die Auswirkungen von Investitionsrisikos, Demand-Response (DR) und Preisobergrenzen auf die langfristige Erzeugungsadäquanz bewertet und eine wirtschaftlich optimale Energiereserve für den deutschen Markt abschätzt.

Zur Lösung der angesprochenen Probleme schlägt diese Studie ein stochastisches, dynamisches EOM-Modell vor, um Ressourcenadäquanz bezüglich Wirtschaftlichkeit und Zuverlässigkeit auf dem deutschen Energiemarkt zu bewerten. Das vorgeschlagene Modell analysiert die Bedingungen für Ressourcenadäquanz auf Basis der Simulation von Unsicherheiten sowohl auf der Erzeugungs- als auch der Nachfrageseite. Eine Monte-Carlo-Analyse über eine große Zahl an Szenarien mit unterschiedlichen Erzeugungs- und Lastbedingungen wurde implementiert, um ein breites Spektrum an möglichen Folgen hinsichtlich Wirtschaftlichkeit und Zuverlässigkeit abdecken zu können.

Außerdem wird ein stochastisches Optimierungsverfahren vorgeschlagen, um risikoneutrale und risikoscheue Investitionspläne für neue Erzeugungskapazitäten basierend auf Schätzungen deren Profitabilität erstellen zu können.

Die präsentierten Ergebnisse stellen die in Zukunft erwarteten Bedingungen für eine langfristige Ressourcenadäquanz im deutschen Energiemarkt dar. Die Energiereservemenge mit der höchsten Wirtschaftlichkeit wird für den deutschen Energiemarkt auf 6.5% der Spitzenlast geschätzt. Das bedeutet, dass ein EOM mit einer Energiereservemenge von 6,5% die langfristige Ressourcenadäquanz in Deutschland sicherstellen würde. Falls die politischen Entscheidungsträger allerdings in erster Linie Risiken vermeiden wollen und unwahrscheinliche Lastabwurfszenarien ausschließen wollen, würde sich der notwendige Energiereservemenge gegenüber dem optimalen Wert erhöhen. Allerdings zeigen die Ergebnisse, dass die Ableitung der Gesamtkostenfunktion rund um diesen Wert flach ist und eine Erhöhung der Energiereserven von 6.5% auf 8% nur zu einem Anstieg der Gesamtsystemkosten von 7% (etwa 26 Mio. €/Jahr) führen würde. Diese zusätzlichen Kosten können als Kosten für die Implementierung eines Kapazitätsmechanismus (z.B. als strategische Reserve), unter Verwendung von verfügbaren oder neuen Gas-und-Dampf-Kombikraftwerken (CCGT), interpretiert werden. Die Ergebnisse zeigen, in Falle der Verfügbarkeit der optimalen Energiereservemenge und einem RES-Anteil von 20% auf dem deutschen Markt, beträgt die gesamte jährliche DR-Abrufzeit 29 Stunden, die maximale DR-Abrufzeit pro Tag 5 Stunden und die maximal per DR zur Verfügung gestellte Energiemenge sind 1.760 MWh/Tag. Das bedeutet, dass jegliche Einschränkung von DR-Abrufen unter diese Werte einen Ressourcenadäquanzwert von weniger als 100% für DR zur Folge hat. Die aus ökonomischer Sicht optimale DR-Kapazität hängt von fünf Faktoren ab: installierte Erzeugungskapazität, Durchdringungsgrad von DR, Bereitstellungs- und Festkosten für DR, Preisobergrenzen sowie der Anteil an RES. Bei einem Anstieg des Anteils von RES von 30% auf 50% würde das durchschnittliche optimale Volumen der wirtschaftlichen DR-Kapazität 5 GW auf 10 GW steigen. Im Falle von 50% Erzeugung aus RES würde die durchschnittliche optimale Kapazität der Notfall-DR mit dem Versandpreis von 500 €/ MWh etwa 15 GW betragen, bei einer Bereitstellungsspanne für DR von 135 Stunden.

A smile costs less than electricity and brings more light - Scottish Proverb

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Abbreviations

CCGT	Combined Cycle Gas Turbine
CONE	Cost of New Entry
CVaR	Conditional Value at Risk
DR	Demand Response
DG	Distributed Generation
EC	European Commission
ECAP	Effective Capacity
ELCC	Effective Load Carrying Capability
ERCOT	Electric Reliability Council of Texas
EUE	Expected Unserved Energy
GDP	Gross Domestic Product
ISO	Independent System Operator
KW	Kilowatt
KWh	Kilowatt Hour
KW.yr	Kilowatt Year
LOLE	Loss of Load Expectation
LOLH	Loss of Load Hour
LOLP	Loss of Load Probability
NEM	(Australian)National Electricity Market
NYISO	New York Independent System Operator
PDF	Probability Distribution Function
PJM	Pennsylvania New Jersey Maryland Interconnection
PV	Photovoltaic

RES	Renewable Energy Sources
RM	Reserve Margin
RONE	Revenue of New Entry
UE	Unserved Energy
VOLL	Value of Lost Load

1 Introduction

1.1 Background

During the last twenty years the electricity sector in Europe has evolved from vertically integrated monopolies to liberalized and competitive arrangements. Former regulated monopolies, which were either state-owned or private, were responsible for electricity generation, transmission and distribution as well as retail supply for all types of consumers. Liberalization of the electricity sector is aimed at privatization, restructuring, and setting up a competitive environment. It is thus meant to increase the role of market forces and economic decisions and decrease the role of political forces. Besides, this reform was expected to bring about better customer responsiveness, higher market reliability and more cost-reflective prices [Sio13]. The electricity sector reforms can potentially lead to either significant benefits or significant costs depending on whether the restructuring and liberalization measures are designed and implemented completely and correctly [J+08].

After liberalization, policymakers' biggest challenge was to find the best structure for competitive markets. Meanwhile, the electricity sector has seen substantial technical developments, which had a considerable impact on its dynamics. The opportunities and challenges resulting from these technical developments have been subject of intense discussion. The main ongoing developments in the electricity sector are briefly presented below.

- Renewable energy – Concerns over climate change are rapidly spreading all around the world and the number of countries that set the decarbonization targets is increasing. The

European Union is committed to a target of an 80% reduction in greenhouse gas emissions by 2050 compared to 1990 levels [EC11]. In the envisaged future low carbon economy electricity plays a central role. The share of renewable energy resources (RES) in the electricity generation portfolio is growing not only to meet the decarbonization targets but also for other reasons such as security of energy supply and sustainable development. Several generous support schemes for renewables such as feed-in tariffs and tradable green certificates in a number of countries facilitate greater RES penetration in the electricity sector. For instance, Germany set ambitious targets to increase the share of renewables in electricity generation to at least 50% in 2030, 67% in 2040, and 80% in 2050. The targets further lie at 30% by 2030 and higher than 60% by 2050 for the share of RES in final energy consumption [VH14]. This transition towards higher utilization of renewable energy is posing both technical and economic challenges for electricity markets.

- Changing generation mix – In contrast to renewables, the electricity generation from carbon-intensive fuels such as coal and lignite is likely to decrease due to stringent greenhouse gas emission reduction policies in a number of countries. Therefore, high future carbon prices plus other environmental standards and decreasing natural gas price may potentially foster reduction in the number of coal and lignite power plants. On the other hand, after the Fukushima nuclear crisis following the earthquake of March 2011 in Japan, a number of countries have decided to decrease or even phase-out their nuclear power plants. For instance, Germany decided to shut down its seven oldest nuclear plants and scheduled the phase-out of the remaining nuclear plants till 2022. These significant changes in the generation mix are likely to lead to new challenges in the electricity sector.

- Distributed Generation – The concept of distributed generation (DG) refers to small-scale electricity generation facilities which are located close to end-users and directly connected to the consumers and electricity grid. The electricity is in this case typically generated from RES, such as small hydro, wind, PV, biomass or biogas which might be accompanied by small-scale storage components. DG makes the generation profile more flexible and leads to higher reliability during peak load hours. Support policies to promote renewables, high costs of building new transmission lines, new developments in DG technologies and liberalization of electricity markets are the main reasons for rapid growth in the utilization of DG.

- Demand Response – Demand response (DR) refers to the active participation of consumers in the electricity market through reducing their electricity demand during peak load periods or shifting their demand to off-peak periods. DR thus can significantly increase system reliability and resource adequacy during peak load events. Consumers have the ability to respond high market prices and an opportunity to reduce their electricity bills by participating in demand response programs. Utilization of DR resources instead of peaking generation units to meet occasional peak load periods can result in a significant reduction in electricity system costs.

- Storage – Storage facilities are another important player in the future electricity sector. Some of storage technologies such as pumped hydro storage have already been widely deployed in the electricity sector while relatively new technologies such as batteries are not yet available on a large scale due to still existing technical constraints and high costs. Rapid technological development and decreasing capital costs of storage facilities foster the penetration of large-scale storage in electricity markets in the near future. Large-scale storage will likely be able to provide fast response to fluctuating generation from variable renewables.

- Energy efficiency – Energy efficiency has already become a priority in the energy policy agenda of developed countries. Energy efficiency measures result in a reduction in primary energy consumption, lower dependency on energy imports and higher security of supply. The European Union has issued the Energy Efficiency Directive in 2012, which is aimed reaching a 20% energy efficiency target by 2020 [Dir12]. Based on energy efficiency policies in this Directive, distribution system operators and electricity retail companies in EU Member States have to achieve annual energy savings of 1.5% by final consumers.

- Resource adequacy – In the wake of market liberalization one of the main concerns is the impact of the new market design on long-term resource adequacy. In the previous regulated monopoly structure, consumers were used to taking resource adequacy for granted.

However, in the liberalized electricity markets consumers may face the risk of resource inadequacy. There is an ongoing discussion in energy policy research on how liberalized electricity markets can stimulate adequate investment in generation capacity.

1.2 Problem Statement

Generation resource adequacy is a highly important issue for producers, consumers, and policy-makers in every country. Electricity plays a major role in economic development and social welfare of every society and any interruption in electricity supply would result in a substantial financial loss and reduction in the social welfare. Hence, ensuring long-term generation adequacy in the electricity market is a top priority for market operators and policymakers. Before liberalization of the electricity system, vertically integrated monopolies were responsible for long-term resource adequacy and reliability of the electricity system. Liberalization of the electricity sector has changed the structure of the electricity market by bringing competition into the electricity sector. One of these changes was the condition that the bidding price of electricity generators must be equal to their short-term marginal cost. Since then, market operators have been concerned about the fact that the deregulated liberalized electricity market might not be able to provide sufficient generation capacity over time. This problem, which is known as resource adequacy or supply security problem, is discussed in the following paragraphs. In energy-only markets, generators receive revenues exclusively from their electricity sales in the market and there is no other revenue stream for their provided generation capacity or reliability contributions. This means that both their variable and fixed costs have to be recovered from these revenues. As a result, adequate revenue streams, i.e. such that allow to recover both costs types, are required to incentivize investment into new generation capacity. Market revenue is determined by market prices which are set by the intersecting supply and demand curves. All generation units bid according to their short-term marginal cost and are arranged from the lowest to the highest bidding price on the supply curve or the merit order curve. RES with almost-zero short-term marginal costs are located on the left-hand side of the merit order curve. Nuclear and coal power plants, so-called base load generators, in turn, have low short-term marginal costs and high capital costs and are consequently placed in the middle of the supply curve. In the meantime, peak load generators such as gas-fired power plants have higher short-term marginal costs and lower capital costs and are thus placed on the right-hand side of the supply curve. A uniform price auction determines the hourly price, which represents a stable equilibrium point for suppliers and consumers. All generators receive the bidding price of the most costly generation unit in the merit order chosen to serve the current load. The revenue obtained by generators is then equal to the product of the market price and the amount of electricity sold at each time period. Therefore, all generators benefit from high prices during peak load and generation scarcity periods. A well-functioning energy-only market should be able to provide cost recovery for all generators to ensure an adequate amount of generation capacity in the market. Scarcity prices provide high inframarginal rents for generators allowing them to recover their fixed costs. That said, the electricity market will face underinvestment in generation capacity if scarcity prices are not high enough or the frequency of scarcity price events is relatively low. Insufficient investment incentives in the energy market leads to resource inadequacy. This research classifies three main reasons for the resource adequacy problem in an energy-only market which are discussed below.

I. Political or regulatory price interventions in energy-only markets are one of the main reasons for the resource adequacy problem. Regulators or policymakers implement a bid cap or price cap on the market prices in order to prevent generators from abusing market power. The side effect of this policy lies in the fact that the real scarcity prices may be suppressed as a result of which generators may fail to recover their capital costs. Subsequently, market will fail to incentivize new investment in generation capacity or to ensure long-term generation adequacy.

II. Resource adequacy problem could occur as a result of increasing investment risks. The cost recovery of marginal producers wholly depends on the scarcity prices, which may be limited to few hours per year. Besides, electricity supply industry has recently faced significant external risks caused by uncertainty in future regulation and market design. Hence, the high risk of unfavorable market interventions makes investors more doubtful about the profitability of new investments in the future.

III. The integration of large shares of RES into the electricity market is another driver which exacerbates the resource adequacy problem. Increasing share of renewables with very low marginal costs leads to the so-called merit order effect which denotes the rightward shift of conventional generators on the supply curve. Three related effects can be observed. The first effect is that the reduction in the utilization of all conventional generators is making their profits shrink. The reduction in the profitability of peak and medium-load power plants is higher due to a greater decrease in both their utilization time and volumes of generated electricity. The second effect is the reduction of both average electricity prices and the occurrence rate of scarcity price events. This effect leads to a significant reduction of inframarginal rent for all generators. As base and medium-load generators have higher investment costs, they are consequently more vulnerable to lower prices. A permanent lack of these inframarginal rents decreases the incentives for new investment and endanger generation adequacy in the long run. The third effect is linked to the increasing share of variable renewables, which results greater variability in the generation profile. The market then needs more investment in reliable backup capacity, i.e. conventional generators, to compensate the intermittency of generation from RES and to maintain the same level of resource adequacy.

1.3 Research Questions

From the definition of resource adequacy problem, the main research questions addressed in this study are:

- **What is the economically optimal condition to ensure long-term generation resource adequacy in the German energy-only market?**

Along with the main research question, the relevant sub-questions addressed in this study are:

- What is the economically optimal reserve margin in the German electricity market? and what are the economic and policy implications of the optimal reserve margin?
- How much is the resource adequacy value of variable renewables and demand response in the German electricity market?

- What is the optimal volume of emergency and economic demand response capacity to ensure generation resource adequacy in the German electricity market?
- What is the impact of investment risk and price cap on the long-term resource adequacy? How sensitive are resource adequacy criteria to these factors?

1.4 Brief Overview of Modeling Approach

Ensuring long-term generation resource adequacy is one of the main priorities for all market participants and policymakers in every country. Therefore, several models to measuring long-term generation adequacy have been developed in literature. In this study a probabilistic model is proposed to evaluate the long-term dynamics of electricity generation capacity expansion in a liberalized energy-only market. The proposed model, which complements already existing deterministic and probabilistic models, uses a probabilistic approach for resource adequacy analysis for two main reasons. First, a rapid growth in the share of generation from variable renewables and an increasing penetration of flexible resources such as demand response results in a high level of uncertainty in the electricity market. Hence, a probabilistic approach is required to properly capture the magnitude and impact of the increasing uncertainty on the resource adequacy condition. Second, the majority of resource inadequacy events are associated with a low probability and infrequent circumstances which are produced due to the combination of periods of extreme limited supply and high load. A probabilistic approach is required to examine a full range of potential resource adequacy outcomes and capture wide distributions of generation and load variables. German electricity market is chosen as the main case study. This market, characterized by significant amounts of investment in renewables in the recent years, is thus suitable for examining the impact of renewables on the long-term generation resource adequacy.

The first step in the methodological approach is to analyze statistical characteristics of supply and load and correlations between variable RES generation, residual load, and market prices (chapter 3). The second step involves modeling the uncertainty in supply and load. The model considers the main generation and load uncertainties which are correlated with resource adequacy, including the capacity credit of variable RES, forced outage of conventional generators, demand growth rate, load forecast error, and weather-related load uncertainty (see 4.4.4 and 4.4.5). For the sake of avoiding unnecessary complexity other types of reliability issues, such as those caused by transmission and distribution outages are not considered. As the third step, a stochastic dynamic optimization framework is proposed to find optimal volume of risk-neutral and risk-averse investment in new generation capacity by estimating the expected profitability of new capacity during its lifetime (see 4.4.7). By using this probabilistic framework, the sensitivity of the resource adequacy criteria to the investment risk, demand response, and price cap is analyzed.

In order to address the outlined research questions, the proposed methodological approach considers both reliability and economic characteristics of generation expansion in the electricity market. The proposed model estimates optimal market conditions which can guarantee long-term resource adequacy, including the economic and equilibrium reserve margin, optimal new generation capacity, and optimal demand response capacity. However, like any other model, this model is not without limitations. For instance, the model does not consider cross-border electricity trade with neighboring interconnected regions. In the present model, DR is activated in response to high electricity prices or system reliability events and the dispatch price of DR is assumed to be higher than the bidding price of marginal producers in the market. The model simulates DR without considering any constraints with respect to whether or not DR can be dispatched in consecutive hours or days. Besides, it is assumed that the DR activated during low reliability periods would only be shifted to off-peak periods. The details of the advantages and shortcomings of the proposed model is discussed in 4.4.1.

1.5 Thesis Structure

This thesis is structured as follows: In chapter 2 a literature review on the resource adequacy problem, different resource adequacy mechanisms including both energy-only resource adequacy mechanism and capacity market mechanism, and a review on the generation investment planning models developed by other researchers are provided. Besides, this chapter provides an overview on the energy transition concept in the German electricity sector. Chapter 3 provides a statistical analysis of raw data from the German electricity market. The main focus on this chapter is to investigate the impact of increasing generation from variable renewables on the performance of the German electricity market parameters from several aspects. Chapter 4 presents a probabilistic framework for long-term generation investment planning in energy-only markets which is the main proposed methodology in this thesis. Chapter 5 provides the optimal long-term generation resource adequacy condition in the German electricity market. The results include the estimated optimal new installed capacity in presence of risk-neutral and risk-averse investors, the impact of both economic and emergency demand response on the long-term resource adequacy and the sensitivity of resource adequacy to the level of price cap in the German energy-only market. Chapter 6 presents the estimated reserve margins associated to different reliability standards and economically optimal and equilibrium reserve margin in the German market. Finally, chapter 7 summarizes the main achievement of this research and presents the main conclusion and derived policy implications.

1.6 List of Publications

The following publications have been made during the PhD study:

Journal Papers

- H. Aghaie and R. Haas, "The economic and equilibrium reserve margin for the German energy-only market" Submitted in Utilities Policy Journal, 2016
- H. Aghaie, "The impact of generation investment risk and demand response on resource adequacy in energy-only markets" Submitted in Energy Policy Journal, 2016
- H. Bosseti , S. Khan, H. Aghaie, and P. Palensky, "Survey, illustrations and Limits of Game Theory for Cyber-Physical Energy Systems", at magazine- Automatisierungstechnik, 2014

Conference Papers

- H. Aghaie, "The value of intermittent renewables in the resource adequacy in electricity markets", 16th IEEE Conference in Electrical Power and Energy, Ottawa, Canada, 2016

- H. Aghaie, "The impact of scarcity prices on resource adequacy in energy-only markets", 33rd USAEE/ IAEE Energy Economics Conference, Pittsburgh, USA, 2015 **(Student Paper Award Winner)**.
- H. Aghaie, and R. Haas, "Efficient Energy-Only Markets", 12th International Conference on the European Energy Market, Lisbon, Portugal, 2015.
- H. Aghaie, and R. Haas, "Competitive Energy-only Markets and Resource Adequacy Problem", 9th Internationale Energiewirtschaftstagung, Vienna, Austria, 2015.
- H. Aghaie, P. Palensky and R. Haas, "Model-based Analysis of the Impact of Effective Competition on Supply Security in Energy Market", 11th International Conference on the European Energy Market, Krakow, Poland, 2014.
- H. Aghaie, P. Palensky and R. Haas, "Analyzing Effective Competition In Energy Market Using Multi-agent Modeling", 13th Symposium Energy Innovation, Graz, Austria, 2014.

2 Generation Adequacy in Electricity Markets

2.1 Literature Review on Generation Resource Adequacy

About two decades ago, electricity market liberalization was implemented to improve the competition in all levels in electricity system including the competition among electricity suppliers both in wholesale and retail sector. The vertically integrated utilities were split up to competitive generation and retail market and a regulated network sector. This reform was expected to create conditions for lower electricity prices and ensure long-term investment in electricity generation. A Well-implemented electricity market liberalization resulted a significant improvements in the electricity sector performance in several countries. However, the incomplete and incorrect implementation of market liberalization has incurred large costs and inefficiency into the electricity system. The lessons learned by the liberalization of electricity markets are discussed in [J+08], [HAK+06], [WLT03]. One of the major changes caused by electricity market liberalization was that the pricing mechanism in electricity market is changed [HARL13]. Before liberalization, regulatory authorities set the market price by dividing the total costs of electricity supply by the sold electricity. After liberalization, electricity prices are determined in hourly auctions in which bidding price of electricity generators in the market should reflect their short-term marginal costs [Bol13].

In liberalized and competitive electricity markets, investors would invest in new generation capacity if they believe that the market would provide enough revenue for them to recover their capital and operation costs [SNP+13]. The electricity spot markets are expected to provide efficient short-term and long-term operation of available capacity and incentives to build required capacity according to the theory of spot pricing [Car82]. However, policymakers are recently concerned about the resource adequacy in near future because there is no guarantee that there would be sufficient investment in the generation capacity to meet the electricity load [DVH04]. There have been several discussions on the main reasons for resource adequacy problem in electricity markets in [CS06] and [Jos08]. The authors in [CS06] argued that current market design with a low price cap and demand response flaws results the missing money that prevents adequate investment in generating capacity. In [Jos08], a variety of imperfections in wholesale electricity market which lead to inadequate incentives to investment in new generation capacity are discussed.

In [FH95], 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 leads to the high risk of generation investment. The first contributions that described the difficulty of investment in peaking plants in energy-only markets were [Sto02] and [DVH02]. A theoretical analysis about the insufficient investment in generation capacity in electricity markets is presented in [Jos06] and [SP06]. These studies emphasize that the current market design may not be able to provide required incentives for investment in the new capacity. The approaches and policies that can help to ensure the investment in peaking units in liberalized electricity markets are discusses in [Doo00]. The authors in that research discuss on the significant impacts of risk aversion and mandatory reserve margin on the generation investment in several electricity markets. In [Bus05], the motivations for resource adequacy policies are explored and the way that these policies are addressing the resource adequacy problem is discussed. The author in [Sim10] argues that resource adequacy problem has been navigated thus far in Australian electricity market due to three main reasons including considerable excess generation capacity, heavy direct and indirect investment commitment by government-owned utilities and the change in the method of reserve plant calculations. It is indicated that the industrial organization and retail price stability are the main reasons that resource adequacy problem is navigated from 2007 onwards. The resource adequacy issue can be divided into three main dimensions including (i) optimal level of generation capacity, (ii) optimal timing of new investment in generation capacity, and (iii) optimal mix of different generation technologies [Roq08].

A simple theoretical model of an ideal wholesale electricity market which addresses to the missing money problem is proposed in [JT07]. The potential impact of operating reserve demand curve concept on the resource adequacy in energy-only markets is discussed in [H+05]. The research by [PA01] proves that an oligopoly structure with entry barriers in an energy-only market leads to underinvestment. In [Ore05], the alternative approaches which are utilized for ensuring adequate investment in electricity generation capacity all around the world are discussed. The authors claim that long-term reserve capacity should be considered as the price insurance and private commodity. Besides, a scheme of how regulatory interventions impose hedging requirements on load serving entities is described. The authors in [COS13] indicate that the optimal expected duration of blackout is equals to the annual capital cost of reliable capacity divided by the value of lost load in the market. They argue that competitive electricity markets cannot optimize blackouts because there is no competitive market price during blackouts and the price is set by administrative rules in blackout conditions.

Some studies have been conducted by the research team in the Brattle group to evaluate resource adequacy issue in several US electricity markets. The authors in [PSN12] evaluated the efficiency and effectiveness of long-term resource adequacy procurement plan in Californian market. The economic and reliability implications of different resource adequacy and reliability criteria have been assessed from a customer and social cost, investment risk and market design perspectives in [PSCW13]. In [CW13], the impact of varying definitions and calculation of reliability standards on the optimal risk-neutral and risk-adjusted economic reserve margin in electricity markets have been estimated.

2.2 The Impact of Renewables on Resource Adequacy

Electricity generation from renewable energy sources (RES) is rapidly increasing due to generous support schemes in most of the European countries. Specifically, the growth of generation from variable RES such as wind and solar is significant. The rapid growth of variable RES share in electricity generation has major impacts on electricity markets. The authors in [HPR+11] summarize the historical development of electricity generation by renewables in European countries, main renewable electricity support schemes in Europe and the effectiveness and efficiency of different promotion policies. The main conclusion is that promotion strategies, regardless of the type of support instrument, must persist for a specified planning horizon. A comparison of the effectiveness of different renewable support policies in several electricity market is presented in [HRH06], [HMH+08], [HEH+04]. The research by [HNA+08] identifies the required modifications in the current trends of energy consumption and energy efficiency in order to achieve a more sustainable energy system.

The integration of large amounts of renewables into the electricity market is a driver which exacerbates the resource adequacy problem. [HARL13] discusses that increasing renewable penetration makes an impact on the long-term resource adequacy by reducing the average market prices and increasing the price spread. The 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 [BBM13], [Agh16], [Agh15]. The first effect is the reduction in the utilization of all conventional generators. 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 prices. A permanent lack of these inframarginal rents lowers the investment incentives and endanger generation adequacy in the long run. The third effect is that the dominance of variable renewables' generation increases the variability of generation profile. Hence, market needs a sufficient amount of reliable backup capacity, i.e. conventional generators, to accommodate for the risks of volatile renewables' supply. However 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.

Figure 2.1 illustrates that the increasing share of variable renewables leads to the rightward shift of the supply curve which is called as the merit order effect. This effect occurs due to the fact that renewables have near-zero marginal cost and they are placed on the left side of supply curve before all of conventional generators. As the right-hand side of Figure 2.1 shows, the merit order effect of renewables results lower market prices at the same demand level. The lower market prices affect on the profitability of both renewable and conventional generators. The capital intensive generators such nuclear power plants would be more influenced by low market prices. As a result, all conventional generators would encounter difficulties to be able to recover their fixed costs and might require support policies. Another impact of merit order effect is that peak-load generators such as gas-fired power plants are operating during a few hours of very high demand period (see Figure 2.1). Besides, the utilization time of other conventional generators such as coal would be decreased.

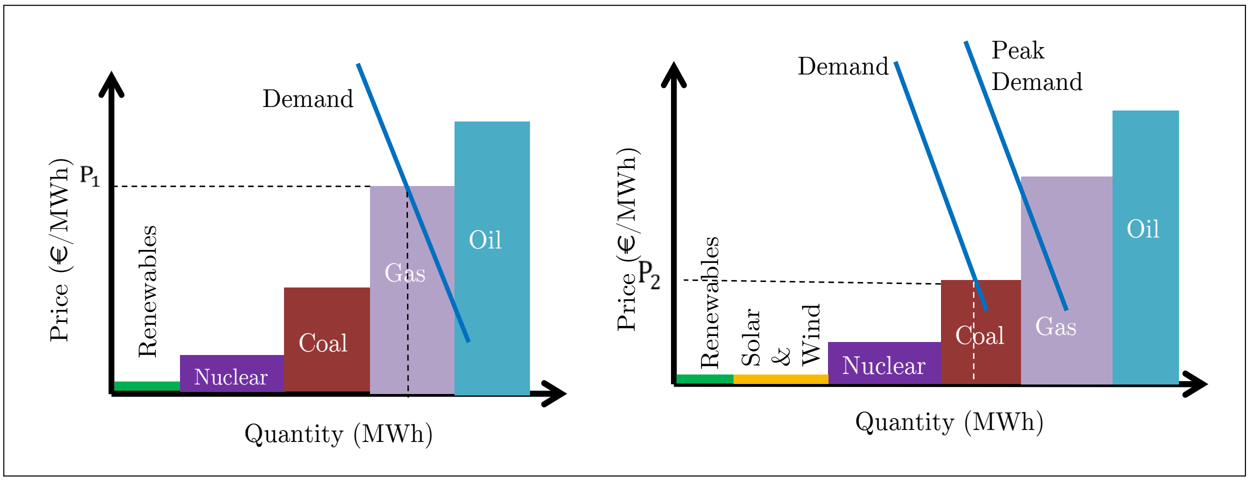

Figure 2.1: Merit order effect of renewables

The impact of the renewables on the utilization of conventional generators is depicted in Figure 2.2. The area between load and residual load shows the amount of MWh generation from conventional generators which is replaced by renewables generation. The volume of reduction in the dispatch of each type of power plants (PPs) is depicted. The increasing penetration of renewables results a considerable reduction in the utilization of all conventional generators. However, the impact of renewables on the utilization of peak load and medium load generators is relatively stronger due to the significant reduction in their load factor. By increasing the share of renewables, these generators will lose higher amount of their share in generation profile which leads to significant reduction in the short-term and long-term profitability of them.

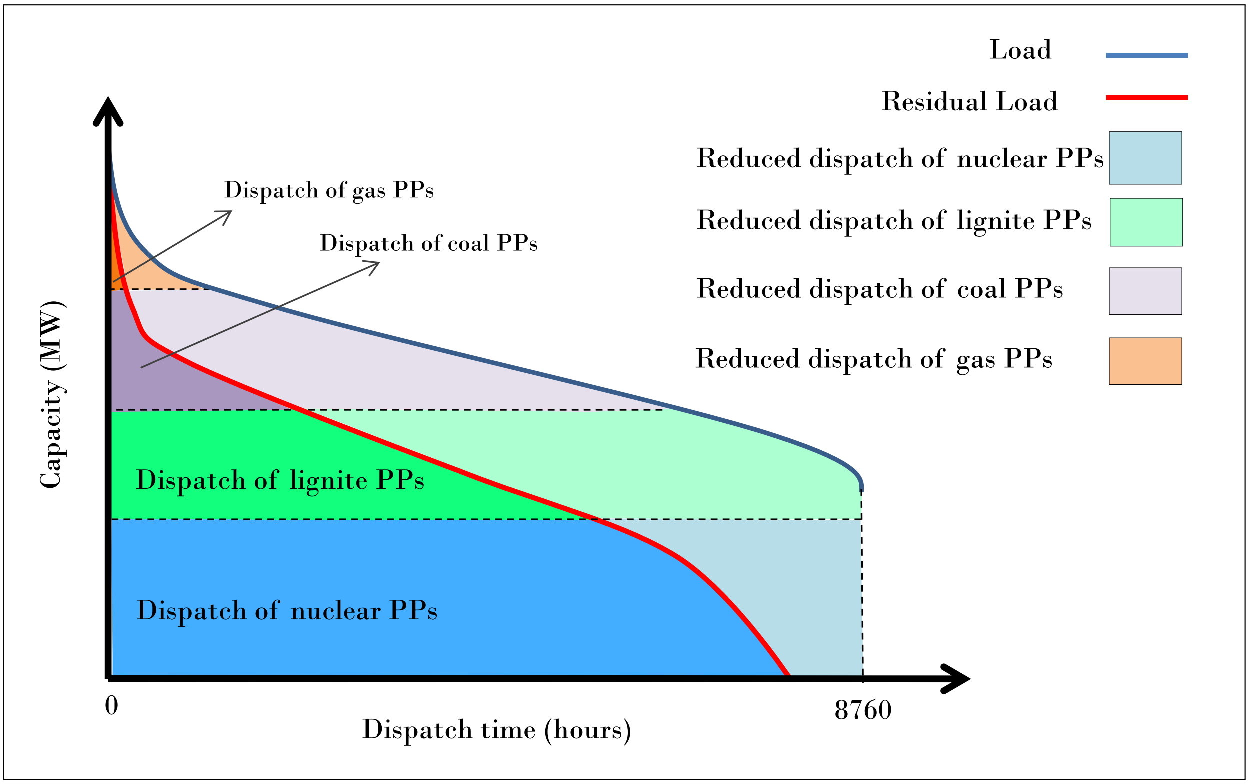

Figure 2.2: The impact of Renewables on the electricity (MWh) dispatched by conventional power plants

2.3 Future Market Design

Regarding resource adequacy, the suggested solutions for the future market design are categorized in two main frameworks [DV04], [CF11], [Haa14]. The first one is an energy-only market approach which includes the price-based solutions such as raising price cap in the market or integrating more flexibility in generation and demand side of the market. Energy-only markets are less forward oriented and the generation technologies with fast ramp capability and price-responsive load products are the best choices to provide the backup capacity in these markets. Scarcity rents derived from price spikes could provide a big portion of revenue stream which is required to cover the investment cost of generation capacity and provide incentive for new investment in new generation capacity in energy-only markets. German electricity market, Australian national energy market (NEM) and Electric Reliability Council of Texas (ERCOT) are operating as energy-only markets. Second, capacity market approach which consists of all quantity-based mechanisms which intend to pay every supplier for the offered MW of capacity into the market besides the payment for offered MWh of electricity. In contrast to the energy-only markets, capacity markets guarantee the fixed payments for new capacity in order to provide incentives for new investment in generation capacity. Flexible generation in the capacity market has a less value compared to the energy-only market [COS13]. However, a hybrid resource adequacy compensation mechanism has been proposed recently which has some features of both energy-only and capacity market design [Sen13a].

2.3.1 Energy-only Market Design

Energy-only market mechanism for resource adequacy is a market-based mechanism with no administrative interventions. In a competitive energy-only market, new generation capacity would be built only if the investors believe that their investment in new generation capacity is profitable. Therefore, energy-only market prices should be high enough that investors expect sufficient returns on their investment costs. These markets do not impose a reserve margin or resource adequacy requirements. The realized reserve margin in energy-only markets might have very large variations each year due to uncertainties in generation and load. Since, market prices determine the level of reserve margin in energy-only markets, there is no guarantee that enough generation capacity will be built to maintain a certain level of reserve margin over time [SNP+13].

The power industry has long discussed the pros and cons of the energy-only and capacity market [COS13]. A key idea of an energy-only resource adequacy mechanism is to elicit the consumers' true willingness to pay for electricity, rather than administrative solutions [ASO08]. It is important to note that in an energy-only market design, all generators need price spikes above their short-term marginal cost to recover their fixed costs. However, the resource adequacy mechanisms in energy-only markets are facing some shortages. For instance, the deficiencies of EROCT resource adequacy mechanism are summarized as the lack of forward-looking capability and the lack of sub-regional pricing [Sen13b].

As one of the biggest advantages, maintaining the energy-only market design in an electricity market helps to avoid the overall complexity related to the introduction of a capacity mechanism. The regulatory and policy interventions such as setting the price cap lower than the value of lost load (VOLL) should be avoided in case the energy-only market is to be maintained. Otherwise, any suppression of high prices would lead to a fewer incentives for investment in new generation capacity and would result an equilibrium reserve margin lower than the economic reserve margin. Besides, increasing flexibility mainly from DR resources in an energy-only market would compensate the low capacity credit of variable RES and avoid the elevated investment costs in conventional meant to back up variable RES. Economic and efficient utilization of DR instead of new additional conventional capacity further contributes to a significant reduction in total system costs. In [AHP14], the main elements of an effective energy-only resource adequacy mechanism are defined as:

- Efficient scarcity pricing
- Flexibility in supply and demand

2.3.1.1 Efficient scarcity pricing

Efficient and effective scarcity pricing plays an important role to provide sufficient returns for marginal producers to recover their capital costs. A well-functioning energy market should be able to provide cost recovery for all types of generators to ensure an adequate level of supply adequacy. In electricity markets, regulators monitor the market to avoid high prices resulted from market power abuse [Jos06]. Therefore, regulators or policymakers set price cap or bidding cap in the market in order to protect consumers from high prices and avoid any strategic bidding by large generators. Since a uniform price auction determines the market price, all generators benefit from high scarcity prices in the case of peak demand. The administratively set price cap during scarcity situation is typically too low which results that all generators are missing a large amount of their revenue per installed capacity during scarcity hours. Consequently, conventional generators are not able to recover their fixed costs and market fails to incentivize new investment in generation capacity which leads to resource inadequacy or missing money problem. In Figure 2.3, it is shown that how a price cap which is lower than the value of lost load (VOLL) results the missing money. The red area shows the per unit missed money of all generators due to the price cap. The amount of missing money depends on the consumers' willingness to pay and the level of price cap. On the one hand, due to the introduction of large amount of renewables in the market, the scarcity situation occurs rarely and the duration of high prices is very short.

All of these factors exacerbate the missing money problem and lead to very low incentives to invest in generation capacity. Hence, it is essential to set the price cap high enough that all conventional generators be able to recover their fixed costs and incentivze new investment in generation capacity.

In [H+12] and [BH14], authors discuss that any suppression of electricity prices during scarcity situation results under-investment in generation capacity. Therefore, an optimal energy-only market should be able to elicit consumers' willingness to pay for electricity especially during the scarcity situations. In literature, the willingness to pay for electricity is estimated by calculating the Value of Lost Load (VOLL) [PHE11]. In [SHAO06], the ERCOT energy-only resource adequacy mechanism is discussed with main focus on the scarcity pricing and the motivation and rationale underlying of increasing the price cap and its implementation details. In ERCOT, the biding price cap is increased from 4,500 $/MWh in 2012 to 9,000 $/MWh in 2015 in order to elicit the true willingness to pay for electricity by customers.

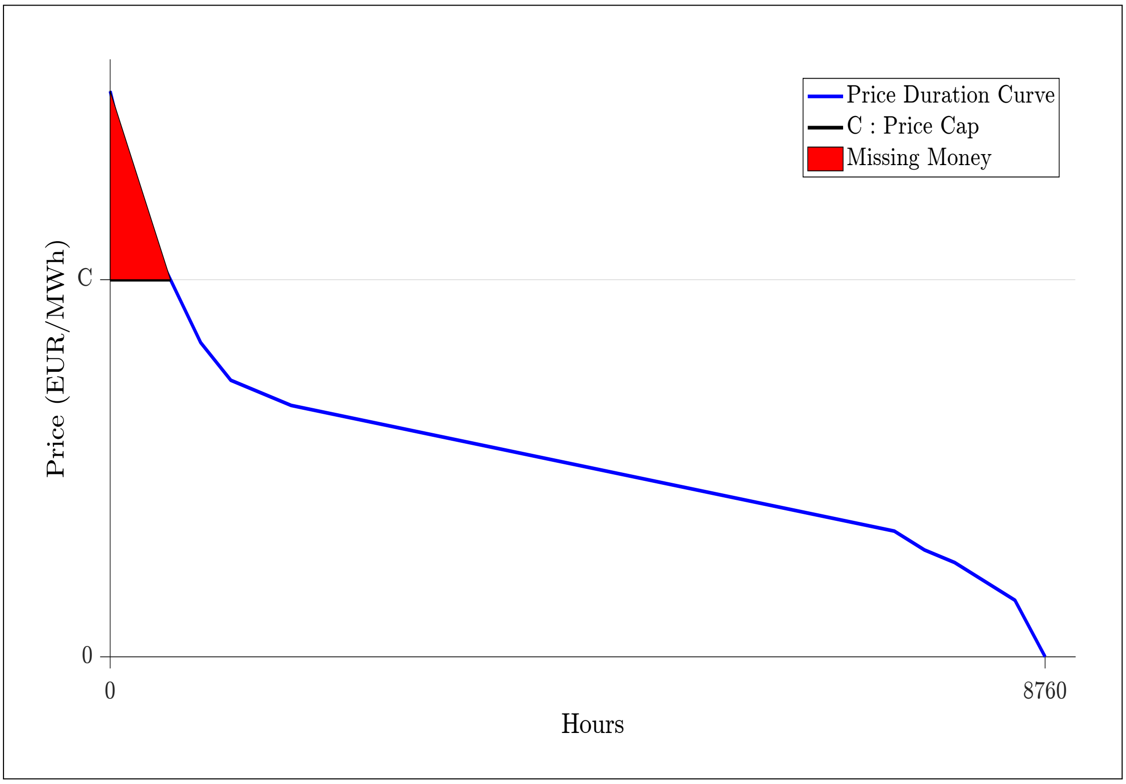

Figure 2.3: The missing money in presence of a low price cap

2.3.1.2 Flexibility in supply and demand

Demand response has an important role in the resource adequacy analysis in competitive electricity markets [VRPA02]. One of the main reasons for resource adequacy problem is the low demand flexibility due to the lack of smart meters or lack of incentives for consumers to participate in demand response programs. The effective participation of consumers in the wholesale market could enhance the efficiency of market operation, resolve the issues with scarcity pricing, and ensure resource adequacy and reduce the need for more conventional generation as the backup capacity. Demand response is more cost-efficient to be used instead of conventional generation capacity to meet peak demand. The impact of demand response on the resource adequacy and reliability in electricity market is studied in [EKM09]. Increasing demand response could protect the market from both load shedding and market power abuse during scarcity condition. A successful energy-only resource adequacy mechanism would require a sufficient amount demand response to be utilized during scarcity situations.

Besides the low demand flexibility, the flexibility in supply side during the scarcity situation is very low which is mainly due to the lack of storage facilities. Storages are another essential component of an energy-only market mechanism. The limited flexibility could lead to the rolling blackout during scarcity situation in an electricity market with tight reserve margin. Specifically, in the electricity markets with higher share of renewables, utilization storages can reduce the volatility of supply profile. Besides, in presence of storages in the market the necessity of building new conventional capacities to provide backup capacity for variable renewable generation decreases.

2.3.2 Capacity Market Mechanism

In contrast to the price-based approaches, capacity mechanisms are quantity-based approaches which address to the resource adequacy problem. Capacity mechanisms provide additional revenue stream for generators which increase the reliability of generation capacity but have less remuneration from selling electricity in the market. The main role of conventional generators in renewable-dominated electricity markets is to provide reliable capacity reserves during scarcity conditions [BBM13]. For instance, increasing share of renewables leads to the less utilization of peaking units such as gas-fired power plants in the market. However, the peaking units have a significant role to increase the system reliability during peak load hours, but their revenue is low due to the limited utilization period. Therefore, capacity mechanisms can provide enough revenue for these power plants in order to enable them to recover their fixed costs.

Capacity mechanisms in energy markets reduce the investment risks and provide a rational trade-off between resource adequacy and investment costs [SNP+13]. Another advantage of capacity mechanisms is to achieve the planning reserve margins with higher probability compared to energy-only markets. The history of capacity market implementation in several electricity markets proves that the design of the capacity market is important in order to resolve the generation adequacy problem and it is possible to have a capacity market that does not fully address to generation adequacy problem [BS13], [CS05], [Jos08]. The author in [DV07] discusses about the advantages and disadvantages of different capacity mechanisms in electricity markets. That study proposes a framework to choose the most appropriate capacity mechanism for each market.

Implementing a capacity mechanism would reduce the probability of load shedding and high-price events. The main disadvantage of a capacity mechanism lies in the fact that it augments the complexity of the energy market design. Besides, the implementation of a capacity mechanism might have significant economic and political consequences and requires further regulatory interventions and less transparency in the future. Finally, the costs for final consumers resulting from implementing a capacity mechanism might be higher than expected due to regulatory interventions and inefficiencies in design elements of the capacity mechanism. In the following, four main capacity mechanisms are described:

I. Capacity Payments: Capacity payments are based on awarding a daily payment to each generating technology if it is available [BVRPA07]. The amount of capacity payment for each generator depends on the firm capacity of that generator which is equal to the contribution of each generator to the reliability of the electricity system. Based on the capacity mechanism in Spain in 2006, each generator is eligible to receive capacity payments by generating electricity for at least 480 hours per year or having certain strategic fuel stocks at their disposal. The main weakness of this implemented mechanism in Spain is that it does not provide either any incentive for generators to be available during scarcity or any incentives for new investment in generation capacity [BVRPA07]. A more elaborated version of this capacity mechanism aims to incentivize new generation investment and prevent existing generators to leave the market. The amount of capacity payment is usually higher when reserve margin in the market is low.

II. Strategic Reserves: Strategic reserves consist of a set of generating units which are withdrawn from electricity market and kept available to operate during scarcity situation. Typically, market operator auctions a certain amount of reserves and these reserves are centrally dispatched by market operator. The auction determines the price of strategic reserves and the capacity revenues for participating generators. As the strategic reserves are supposed to operate for few hours per year, most economical way would be to use the mothballed generation units as strategic reserves [DV04]. Strategic reserves could be deployed under a capacity of price trigger. It means that these reserves could be triggered if the generation capacity in the market is nearly insufficient or the market price is reached to a certain level.

III. Capacity Credits: Capacity credit mechanism is an approach in which electricity suppliers have to purchase capacity credits in order to cover the forecasted peak load plus the required reserve margin in the next few years. Therefore, this mechanism ensures an adequate level of reliability and generation capacity for the near future in the market. The reason that capacity credits are forward-looking is to signal the need for new generation capacity early enough and provide incentives for sufficient generation investments in time [BBM13]. This mechanism in applied in the PJM capacity market by annual auctions with 3 years forward-looking period.

IV. Reliability Options: Reliability options are designed as a financial version of capacity credits. An independent agent, for example the TSO, purchases the reliability options on behalf of consumers from generators which are selling it. A reliability option is called when the spot price exceeds the strike price of that reliability option. Strike price of reliability options is set slightly higher than the marginal cost of the most expensive generation unit in the market. Generator that sells reliability options must pay the difference between the spot price and the strike price to the independent agent. The generator who has sold reliability options will be penalized if the plant is not available when the option is called [Bid05].

The reliability options guarantees the availability of adequate generation capacity during scarcity conditions and protect consumers from high prices. Also, since the generators have to pay back the market price and option's strike price difference to the consumers, this mechanism avoids the market power abuse during scarcity conditions [BBM13].

2.4 Demand Response

Demand response (DR) denotes an intentional change in electricity consumption by customers in response to electricity prices or imbalance in the electricity system. Consumers may temporarily reduce their electricity consumption during peak load and high-price periods by shifting some of their load to off-peak periods. Additionally, customers may use their own distributed generation to effectively lower their net consumption from the market perspective [AES08]. DR programs aim to provide incentives to consumers for optimally managing their electricity consumption [BE02]. Different DR programs have been implemented around the world to allow a large participation of consumers in electricity markets [THL10], [PH11]. These programs are differentiated according to the type of the approach used to incentivize DR deployment.

Type of DR	Definition
Direct Load Control	DR program sponsor shuts down the customer's electric equipment on short notice. This program are offered to small-scale residential or commercial customers.
Interruptible load	(A part of) the load of costumers who are under DR contract is interrupted during system contingencies.
Price responsive demand	DR resources which are triggered by high wholesale market prices.
Spinning emergency reserves	DR resources which are synchronized and activated within the first few minutes of an emergency event in order to provide balancing between supply and demand.
Non-Spinning emergency reserves	DR resources which are activated after a delay of more 10 minutes of an emergency event. Both spinning and non-spinning reserves cannot be called outside their contracted hours.

Table 2.1: DR program classifications

According to [WMSS13] and [NSP+14], different types of DR programs in electricity markets are presented in Table 2.1.

[C+09] provides an estimation of nationwide DR potential, how much of this potential can be achieved, identification of barriers to DR programs and recommendation for overcoming to them in the United States. Under the Business-as-Usual scenario, the reduction in peak load by DR is estimated to be 38 GW by 2019 which is equal to 4% of peak load. However, the reduction in peak load under the extended Business-as-Usual scenario reaches to 82 GW by 2019 which is equal to 9% of peak load. The authors identify a number of barriers needed to be overcome in order to achieve the estimated potential of DR. The regulatory barriers include the lack of direct connection between wholesale and retail prices, lack of real times information sharing between market participants, inefficiency and ineffectiveness of DR program design, and disagreement on cost-effectiveness of DR programs. The economic barriers include the inaccurate price signals and lack of sufficient financial incentives for consumers to participate in DR programs. The technological barriers include the lack of advanced metering infrastructure, lack of interoperability standards and high cost of some of required technologies. The economic potential for future demand response in Germany is estimated in [Gil16]. The authors conclude that the major benefit of DR utilization in Germany is its ability for peak shaving, whereas the integration of variable RES is lower. Theoretical demand response potential in European countries is assess in [Gil14].

A framework for evaluating the cost-effectiveness of DR is proposed by [WMSS13]. The cost-effectiveness of DR is measured by five criteria including the societal cost, total utility and DR program participants' cost, program administrator cost, participant cost and the impact on utility rates. The long-term dynamic effects of DR policies in wholesale electricity markets is assessed in [CS16]. The authors examine the economic performance of different energy policies such as the evolution of generation mix and the carbon emission level o DR deployment over time.

2.5 German Electricity Market

The German electricity market is one of the markets with largest share of renewables in the world. This market is well connected with the electricity network of neighboring countries. The first phase of German electricity market opening is described in [BB06]. The German market had a lot of generation capacity surplus before the liberalization. Legal unbundling of generation, transmission and distribution of electricity created a more competitive wholesale and retail market. Before in presence of excess generation capacity, the allocation of power plants was independent from network considerations [PCS13].

The generation sector of German electricity market is dominated by four large companies including Eon, EnBW, RWE and Vattenfall which have a balanced share of the market [PCS13]. The renewable generators have priority to feed their electricity generation into the network and conventional generators adjust their generation according to the renewables generation. The share of renewables is rapidly increasing in German electricity market. The installed capacity in renewable generation in Germany is increased from 32 to 60 GW within five years from 2005 to 2010. The wholesale electricity prices in Germany are set in European Energy Exchange (EEX). The prices of electricity traded in Over The Counter (OTC) transactions follow the EEX prices.

The high-voltage grid in Germany is mainly operated by the four large companies, Eon, EnBW, RWE and Vattenfall. Also, the distribution networks in Germany are operated by local companies.

German Energiewende plan is a transition to a low-carbon and sustainable energy system. The main pillars of German Energiewende which was passed in 2010 are: greenhouse gas (GHG) emission reduction of 80% to 95% by 2050 (relative to 1990), increasing the share of renewables for electricity generation up to 80% in 2050, increasing the share of renewables in final energy consumption to 60% in 2050, and improving energy efficiency to reduce electricity consumption by 25% in 2050 (relative to 2008) [VH14].

Since last decade, German government has strongly promoted the investment in renewable energy in order to comply with Energiewende targets. Initially, most of the investment in renewables was on wind power plants which are mainly installed in northern Germany. Then, investment in PV generation was significantly increased all around the country. Besides, German government decided to phase out nuclear power plants few days after the Fukushima nuclear accident in Japan [KW14]. According to the nuclear phase out plan in 2011, seven oldest plants were obliged to close down for six months (moratorium) that would be followed by total phase out by 2022. The amount of new installed capacity in renewables was higher than the reduction of nuclear plants and leads to an overall increase in generation capacity in Germany. The combination of rapid increase in renewable generation capacity and moratorium leads to increasing need for transmission lines from north to south Germany.

The German energiewende is expected to rise the electricity price in future for three main reasons [PCS13]. First, the short term marginal cost of gas or coal power plants which are the backup capacity for variable renewables is higher than the short term marginal cost of nuclear power plants which are being phased out [WRNB+08]. Therefore, the average price when the conventional generators are the marginal producers in the market will be higher. Even though, large share of renewables in the market results lower prices which leads to lower incentives for investment in new generation capacity and consequently higher prices during peak load [Erd11]. Second, gas and coal power plants will have the role as back up for variable renewable generation instead of nuclear power plants after Energiewende. By considering the future carbon price, the conventional generators are required to buy CO2 certificates for their greenhouse gas emissions. Therefore, the short term marginal cost of gas or coal power plants will be even higher which results higher electricity prices. Third, renewables have high investment costs and the additional cost of renewables is financed by a surcharge which is paid by consumers. By increasing share of renewables, the surcharge paid by consumers would be increased which results higher electricity prices [PCS13].

In [PCS13], the authors provide the lessons to be learned from German energiewende, which is listed below:

I. Implementing a turnaround in energy sector of a country needs long time horizon. The German experience proves that Energiewende could have been implemented at lower costs if there was sufficient lead time for industry to handle the challenges.

II. Long-term planning to increase distributed generation by renewables should be accompanied by corresponding expansion of transmission network.

III. Investors and producers need long-term incentives to restructure their long-term plans in order to be compatible with Energiewende targets.

IV. Increasing generation from renewables results in significant rise in the overall electricity system costs. It is required to figure out how these costs should be allocated and shared.

V. Based on the results in this thesis, it is recommended that the increasing investment in renewable generation should be at the same pace as investment in the flexibility sources in generation and demand such as storages and demand response technologies in order to avoid a very high total costs in electricity system.

2.6 Generation Investment Planning Models

In a liberalized electricity market, the task of independent system operator (ISO) is to find an optimal electricity dispatch that maximizes the total system surplus. The surplus, which is known as social welfare consists, consists of the generator and consumer surplus and defined as the difference between the willingness to pay for electricity by consumers and the cost of electricity generation by generators which is depicted in Figure 2.4. The ISO determines the intersection of supply and demand curve by solving and optimization problem in order to maximize the social welfare at each time period of market operation. By assuming that the bidding curve by generators accurately reflects their marginal cost of electricity generation and the bidding curve by consumers accurately reflects their true willingness to pay, the social welfare maximization problem is an economic dispatch problem. The general problem of finding optimal level generation investment is similar to the economic dispatch optimization problem. In both optimization problems, the aim is to maximize the social welfare for both producers and consumers. However, the long-term generation capacity costs are considered in the generation investment optimization problem.

In literature, several models are developed in order to study the optimal investment in generation capacity in electricity markets. In [Dah11], the generation expansion planning and investment models in literature are classified into two groups: (i) Generation expansion models which mainly analyze the optimal investment planning of a single generation company in market, and (ii) models which represent the generation investment issue in whole electricity market by simulating the behavior of multiple market participants and the dynamics of generation investment. Several modeling approaches are utilized in literature to model the generation investment in electricity markets. These main approaches including system dynamics, agent based modeling, real options and game theory are discussed in below.

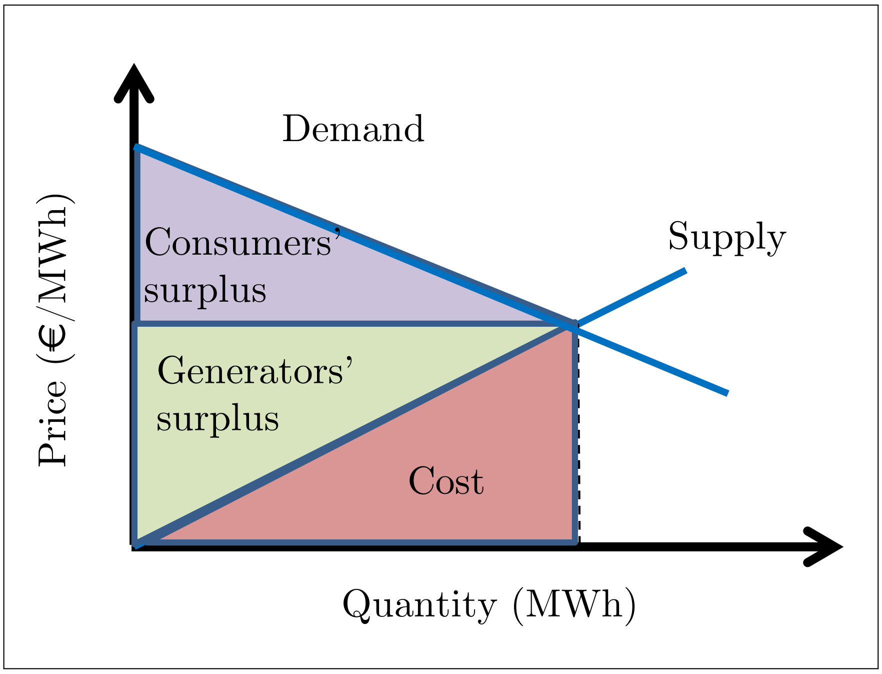

Figure 2.4: Consumer surplus, producer surplus and total surplus in supply-demand diagram

2.6.1 System Dynamics

System Dynamics is an approach to study the behavior of the complex systems over time. This model simulates the casual effects of the interactions within the components of a system in time. In this approach, a casual loop diagram is an appropriate tool to represent the feedback structure of the system [TMGF13], [AMSEE12]. In [DVH08], a system dynamic model is proposed to study the impact of different resource adequacy mechanisms on the generation investment in an electricity market. System dynamics approach is used to comprehend the dynamics of interactions between the different components of the energy market. In [DVH08], a system dynamic model is presented to test the performance of different market designs including energy-only market and electricity market with capacity mechanisms. A system dynamic model of an energy-only market is proposed to study the impact of price cap and demand response on the resource adequacy in [AH15]. The effectiveness of different capacity mechanism to ensure long-term resource adequacy is analyzed using system dynamics model. The system dynamics model is utilized to model long-term generation investment planning in Norwegian power market in [Bot03]. The proposed model is considered the most important relationships which influence on the long-term dynamics of generation expansion in electricity market. This study recommends that the decision makers should be involved in the development of system dynamics generation investment models in order to obtain the best results from model.

2.6.2 Real Options

One category of generation investment models are using the real options theory to evaluate investment decision making under uncertainty [DJS01], [BIW05], [DO03], [BK04]. In [BK07], a stochastic dynamic model is utilized to find the optimal timing of power generation investment for decentralized and profit-maximizing investors in a competitive electricity market. That study uses a real options approach to model the generation investment under uncertainty and analyze how uncertainty makes an impact on the optimal investment timing. In [DO03], real options approach is utilized for short-term valuation of electricity generation assets.

2.6.3 Agent-based Modeling

Agent-based modeling is an approach to model the actions and interactions of multiple agents within a system. Agent-based models are composed of autonomous agents with ability to learn and adapt to the surrounding environment in order to achieve its own goals. In [BMV+07], agent-based modeling is applied for long-term generation investment decision making in decentralized generation companies. In this model, the agents are the independent generation companies interacting with each other in the market. Each generation company assesses the profitability of investment in new generation capacity by considering the impact of new investment on the profitability of its own existing portfolio. Each generation company has an objective to maximize its own profit in the long-term operation in the market. An agent-based model is utilized to analyze the long-term generation expansion and optimal long-term investment decisions in [GDPQ04]. In literature, agent-based models are mainly used for spot electricity markets, carbon emission markets, and long-term policy issues in both of these markets [RCV14]. A critical survey of agent-based wholesale electricity market models is presented in [WV08]. This study provides a discussion on the shortcomings of existing agent-based approaches in electricity market modeling and the open issues which should be addresses by researchers in this field.

2.6.4 Game Theory

Game theory is an approach to model the strategic interactions between different players in a system. The main characteristic of game theory approach is its ability to model the strategic behaviors by market participants such as coalition in the market such as coalition between market players. Game theory has been widely used in power system application such as modeling the electricity system reliability, and regulatory and policy perspectives [SHPB12], [BKAP14]. A game theoretic approach is proposed to model the generation capacity adequacy and compare the different investment incentive approaches in electricity markets in [Kha11]. In this study, dynamic programming is used to model the stochastic environment of the market and find the most cost-efficient mechanism for ensuring long-term generation adequacy. In [CWV01], a noncooperative game theory approach is applied to compare the generation investment in competitive electricity market in different competition scenarios. The scenarios include the Cournot model of oligopoly behavior and coalition between generation investment companies. Other competition scenarios such as Stackelberg and Bertrand competition in Generation expansion model are utilized in [MS05]. In [NSP+14], a strategic energy risk valuation model (SEVRM) is utilized to estimate the economically optimal reserve margin in electricity markets by simulating generation availability, load profiles, load uncertainty, inter-regional transmission availability, and other factors.

2.6.5 Probabilistic Models

Probabilistic approaches are powerful tools for uncertainty modeling and risk assessment in power system applications [RNN+06]. These approaches consider the probability distribution function of the uncertainties in the model which enables the sensitivity analysis and assessment of the model parameters over a wide range of uncertainties. In literature, Monte Carlo simulation is mostly used to model the uncertainty in electricity markets [RFD01], [TCF10]. The paper [RNN+06] introduces a probabilistic model for generation investment to analyze the combined impact of multiple uncertainties on the profitability and value of new generation investment in the market. In [LSM06], a probabilistic approach is used to simulate the optimal generation capacity by considering the uncertainty in market prices. A stochastic dynamic investment model for long-term generation expansion planning in competitive electricity markets is proposed in

[DB08]. This model uses stochastic dynamic optimization model to analyze the effect of different market designs on the generation investment. A stochastic model based on Monte Carlo simulation to evaluate the expected profit cost, and risk associated to the different conventional generation technologies is presented in [VMW10]. In [NSP+14], a strategic energy risk valuation model (SEVRM) is utilized to study the reliability and resource adequacy in electricity markets by simulating generation availability, load profiles, load uncertainty, inter-regional transmission availability, and other factors.

3 Statistical Analysis of the German Electricity Market

3.1 Introduction

In this chapter a statistical analysis of the German electricity market using generation, load and market price data is performed and the results of the analysis are discussed. The German electricity market has been faced with growing volumes of investment in renewable energy sources (RES) in the recent years. Therefore, the case of this market seems suitable for examining the impact of RES on various market parameters. In order to provide an overview of the German electricity market, a data set including hourly actual and day-ahead forecasts of renewable generation, hourly load values as well as hourly day-ahead prices in Germany are investigated. In this section the term "renewables" refer to variable renewables such as wind and Photovoltaics (PV). Such a delimitation is justified by the fact that the main challenges in the German electricity market such as generation and price volatility, high generation forecast errors, and negative prices are mostly a result of increasing shares of variable RES.

Most of renewable generation in Germany is traded at the day-ahead market. At the European Power Exchange (EPEX), which hosts day-ahead auctions for the German market, hourly prices for each day are determined through a uniform price auction held on the previous day. Suppliers of RES bid their forecasted generation quantities for the next day into the auction and the difference between the actual and forecasted renewable generation volumes is traded at the intra-day market.

The data set which is used to perform this analysis includes hourly electricity generation by different generation technologies, hourly day-ahead forecasts of renewable generation, hourly load values, hourly day-ahead market prices, and forced outage period of conventional generators in 2012 and 2013. Besides, a historical demand growth rate and peak load variations in the German electricity market from 2000 to 2015 are utilized to model load growth in the long-term.

3.2 The Effect of RES Generation on the Market Price

In the day-ahead market auction, the quantity bid by renewable generators is equal to the day-ahead forecast of their generation. Therefore, in order to investigate the effects of renewable generation on the price, a correlation between hourly day-ahead forecasts of wind and PV generation and hourly day-ahead market prices is analyzed. In Figure 3.1 the scatter plot represents the variation of renewable generation versus day-ahead market prices. Results show that by increasing renewable in-feed to the market, the market price decreases. The analysis of day-ahead market prices in Germany shows that there were 39 hours with negative day-ahead prices in 2012. Almost all of these negative prices occurred between 12 a.m to 8 a.m. between December, 25 and January, 5, a period in which electricity load is quite low. On the other hand, almost all price spikes in the German market occurred during February and December on the days when electricity consumption is very high due to cold weather conditions.

The scatter plot of residual load with respect to the market prices is depicted in Figure 3.2. Residual load is calculated by subtracting hourly renewable generation values from hourly load values. This figure shows that residual load and price are highly correlated and increasing residual load results in higher market prices. The slope of the price variation curve is relatively steep during periods of high residual load, which means that prices tend to increase rapidly when either gas-fired power plants or emergency operating reserves become marginal producers in the market. Results show that negative prices occur when residual load is low. A low residual load may occur in the event of low electricity demand, high volumes of electricity generation from RES or the combination of the two. Similarly, high price spikes occur during high residual load events, which may result from a very high load, low volumes of generation from RES or the combination of the

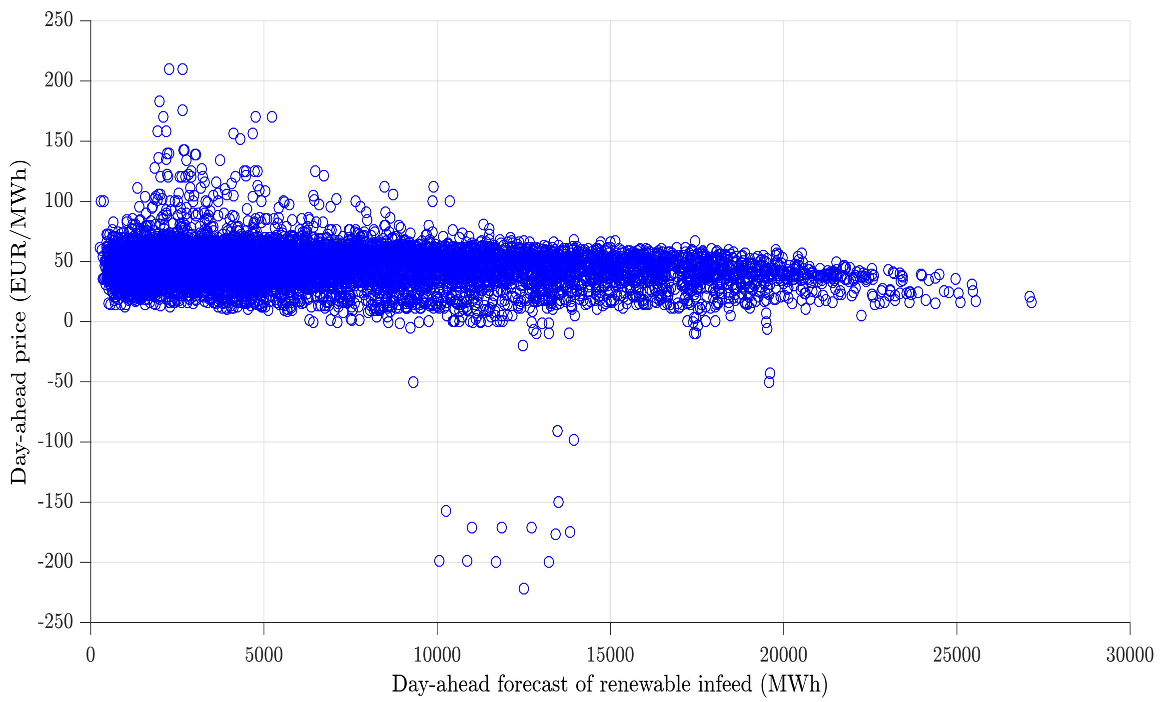

Figure 3.1: Renewable generation and day-ahead market price variations in Germany in 2012

two. This plot can thus be interpreted as a merit order curve of conventional generators at the day-ahead electricity market.

3.3 Variability of RES Generation

Electricity generation from variable RES such as PV and wind differs from conventional generation in many ways. Electricity generation from solar energy and wind is highly dependent on specific weather conditions such as wind speed, air density, solar irradiation, cloud cover, and temperature. High variability of renewable generation in electricity markets with large shares of RES could lead to several issues potentially affecting power system operation and planning. This section provides descriptive statistics of the variability of wind and PV generation and the variability in residual load. Hourly variability of each parameter is equal to the hourly gradient of that parameter. The minimum, maximum, mean absolute, and standard deviation of hourly variation of renewable generation and load is presented in Table 3.1.

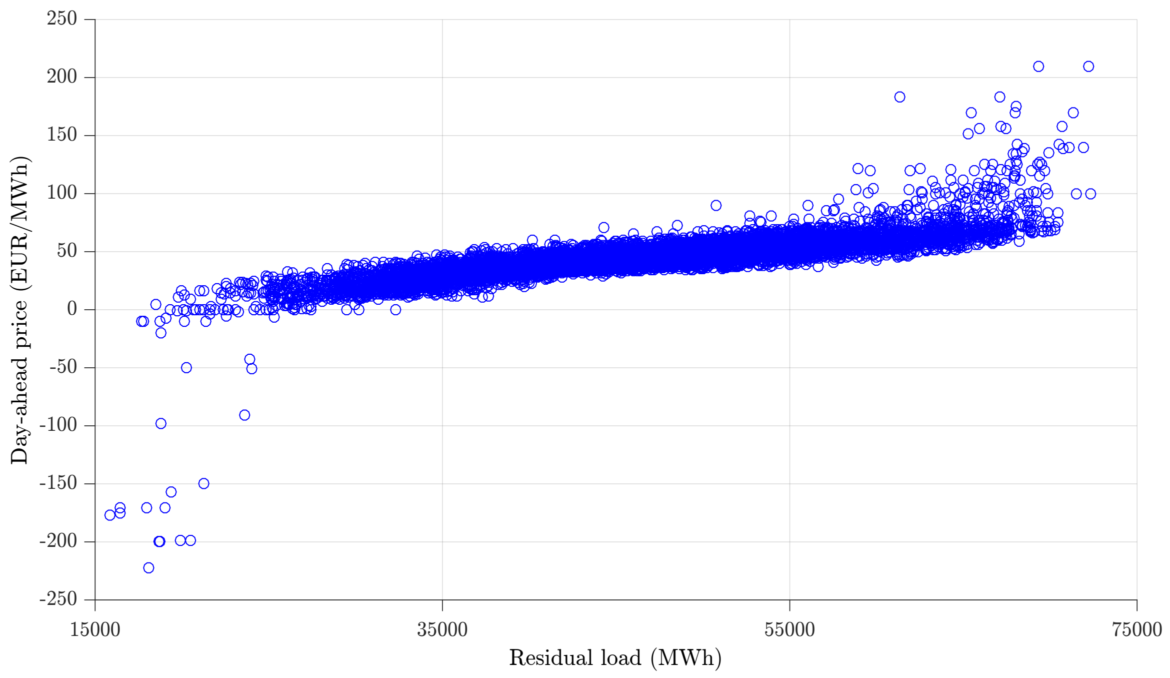

Figure 3.2: Residual load and day-ahead market price variations in Germany in 2012

The installed capacity of wind and PV generation in Germany in 2012 amounted to 31,332 and 33,033 MW. Taking into account the capacity factor of 12% for wind generation and 9% for PV generation, the average hourly generation from variable RES would equal 6732 MWh. The table shows that the maximum and minimum hourly renewable generation gradients are +5.91/-5.34 GW. The ratio of the maximum and minimum renewable generation gradient to the average hourly renewable generation is +88% and -80%, respectively. Results show that the average hourly gradient of renewable generation is approximately 1 GW and the ratio of average gradient of renewable generation gradient to the average renewable generation is 15%. These findings prove that the variability of RES generation in the German electricity market is high. By increasing the share of variable RES, the market will consequently face a higher level of variability of the generation profile.

A histogram of hourly variation in electricity generation from solar and wind energy in Germany in 2012 is depicted in the top plot in Figure 3.3. The histogram for the percentage of the variation in RES generation is depicted in the bottom plot. The percentage of variation in renewable

	max/min [GW]	mean [GW]	standard deviation [GW]
Wind Gen.	+3.03/-2.13	0.27	0.38
PV Gen.	+5.21/-4.8	0.83	1.39
Wind+PV Gen.	+5.91/-5.37	0.99	1.49
Load	+10.47/-6.24	2.06	2.70
Residual Load	+10.89/-7.12	2.06	2.68

Table 3.1: Descriptive statistics of the hourly gradient of renewable generation and load

generation lies in the range between 0% to 250% of hourly renewable generation and the mean value is equal to 17%. It could be interpreted in a way that hourly variable RES generation varies on average in the range of 17%. Increasing the share of RES in the electricity market will result in more variability of the generation profile. Therefore, an adequate volume of flexible generation capacity is required in electricity markets with high shares of RES in order to provide a rapid response to the high variability levels of renewable generation fleet. Besides, balancing markets will play an important role in providing the required short-term flexibility in order to compensate the uncertainties and stochasticity of generation from variable RES.

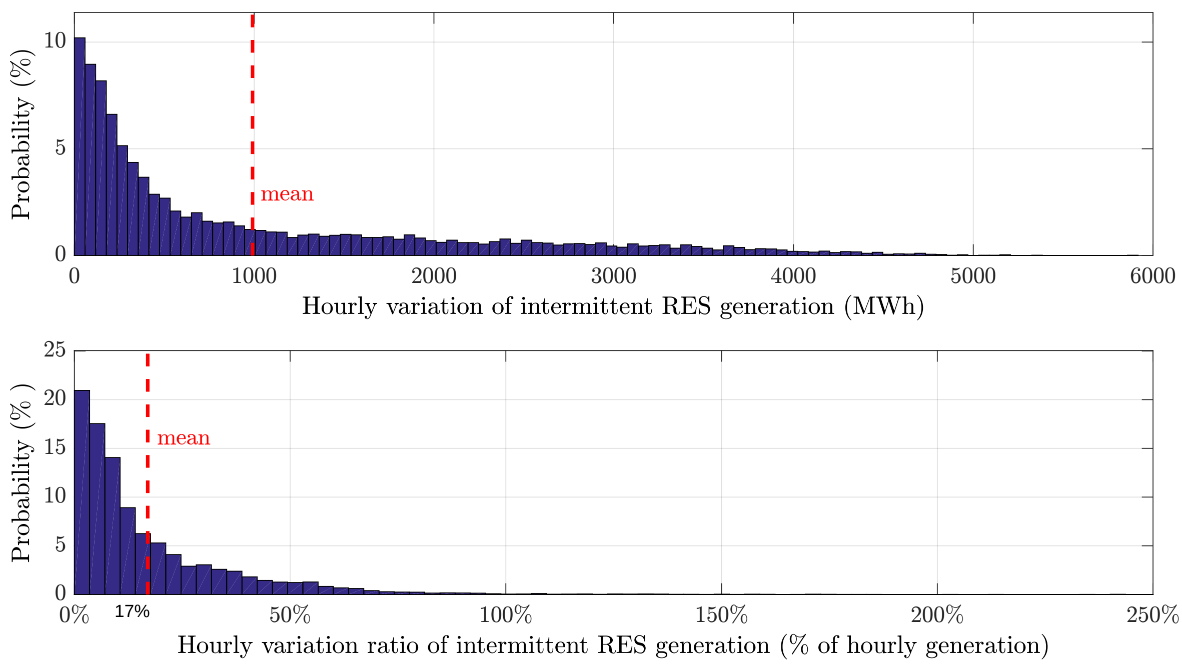

Figure 3.3: Renewable generation volatility in one hour in Germany in 2012

Hourly variation of renewable generation versus hourly price variation is depicted in Figure 3.4. The outliers both in case of price variability and in case of renewable generation variability are excluded from the data set. Results show that during the low variability of RES generation, price spread is relatively high. By increasing the variability of renewable generation, market price spread decreases. According to the initial expectation, higher volatility in renewable generation would result in higher price variations, however, the results proved the opposite. The reason for this lies in the fact that price variability depends on several factors such as hourly electricity load, load variations, available generation from different generators and the share of RES in the generation mix. Therefore, price variability must be analyzed by considering all related factors.

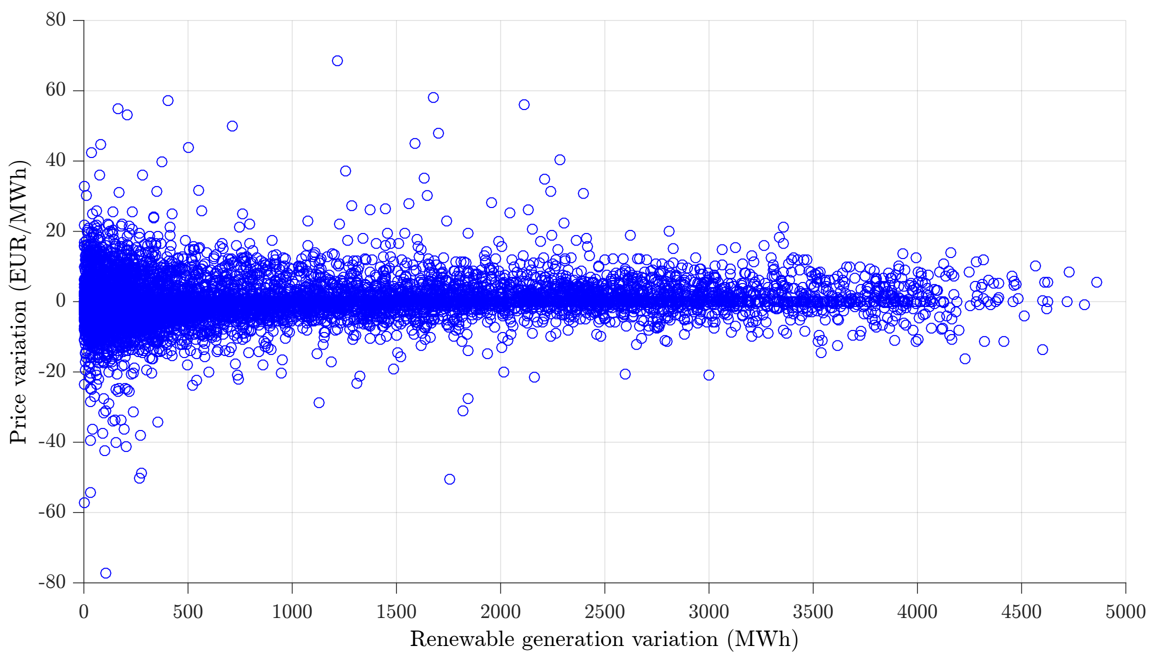

Figure 3.4: Hourly variation of renewable generation versus price variation in Germany in 2012

3.4 RES Generation Forecast Error

Day-ahead forecasts of renewable generation are essential to determining the price at the day-ahead market auction. Here grid operators provide renewable generation forecasts for the next day with hourly resolution. The difference between real and forecasted renewable generation is traded at the intra-day market. More precise forecasting of renewable generation is a key factor to facilitating further integration of RES in the future. The renewable generation forecast error is defined as a difference between forecasted values and the actual values. The histogram of the wind and PV day-ahead forecast error in the German electricity market is shown in Figure 3.5. According to the upper plot, the day-ahead forecast error for renewable generation lies in the range between -7 GWh and 8 GWh. The renewable generation forecast error has a normal distribution with the mean value of -170 MWh and the standard variation of 1200 MWh. The lower plot shows the histogram of forecast error values as a percentage of hourly load which has a normal distribution with the mean value of -0.3 % and the standard variation of 2.2 %. Results show that the forecast error of renewable generation is relatively high. By increasing the share of variable RES in the market, the volume of the forecast error will increase, which could lead to inefficiency and high operation cost for electricity system. Hence, besides improved forecasting techniques, adequate volume of flexible generation at the intra-day market is required to offset the forecast error of renewable generation.

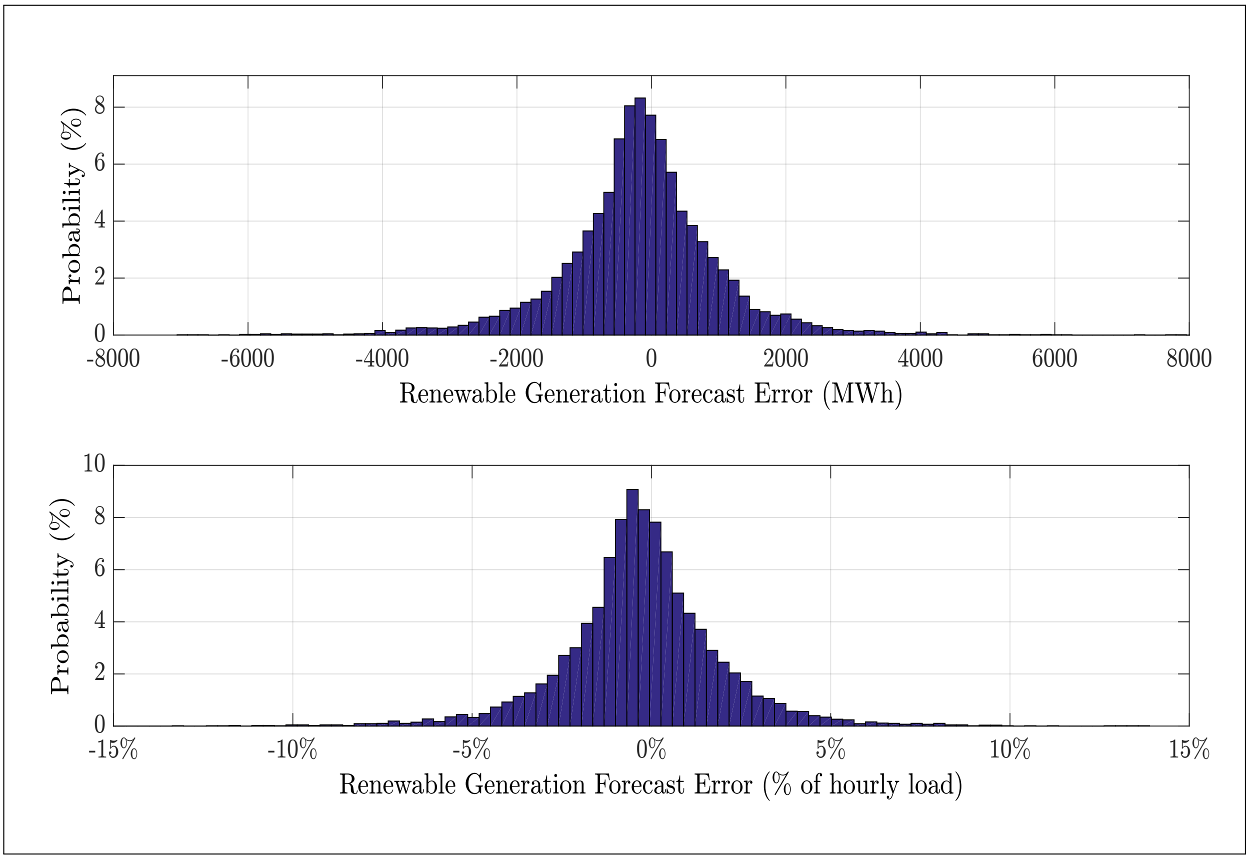

Figure 3.5: Day-ahead forecast error of wind and PV generation in Germany in 2012

3.5 Seasonal Load and Price Characteristics

In this section the average load and average day-ahead price in each season in the German electricity market are analyzed. In Figure 3.6, the average seasonal load in 2012 is depicted. Peak load events in Germany are typical for cold winter evenings due high electricity consumption by electrical heating systems. The load pattern in the winter season shows two peaks at noon and in the evening around 7p.m. The noon peak occurs due to high residential and commercial activities such as cooking around 12 p.m.. The evening peak is mostly caused by increasing consumption from electrical heating systems, which means that in summer this peak disappears. Besides temperature, other factors such as the length of the daytime and seasonal economic and social activities have an impact on seasonal load profiles. Consequently, the market price during the winter peak load period is higher than the prices during peak load periods in other seasons. As is shown in Figure 3.7, the average daily market price follows the daily load pattern in each season. Average daily market price curve in the summer season is smoother and has fewer variations while market prices during winter are characterized by higher daily variability.

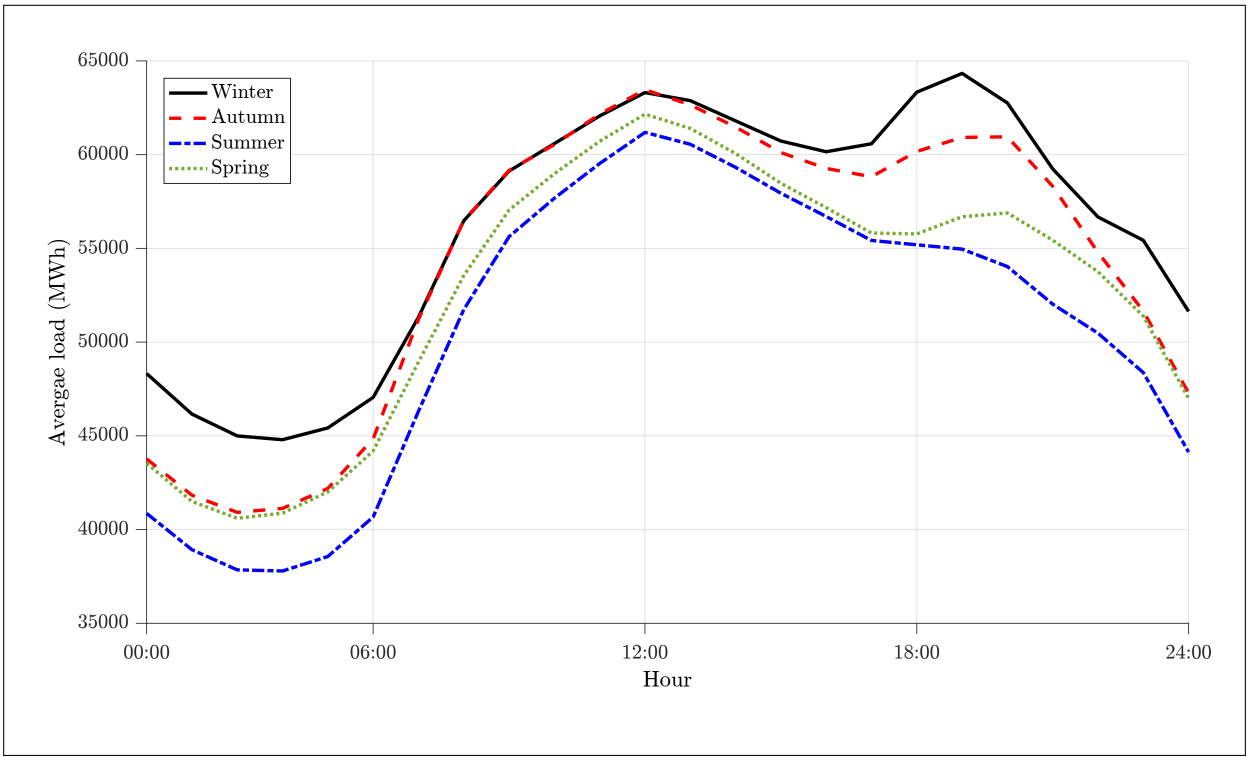

Figure 3.6: Average hourly load in different seasons in Germany

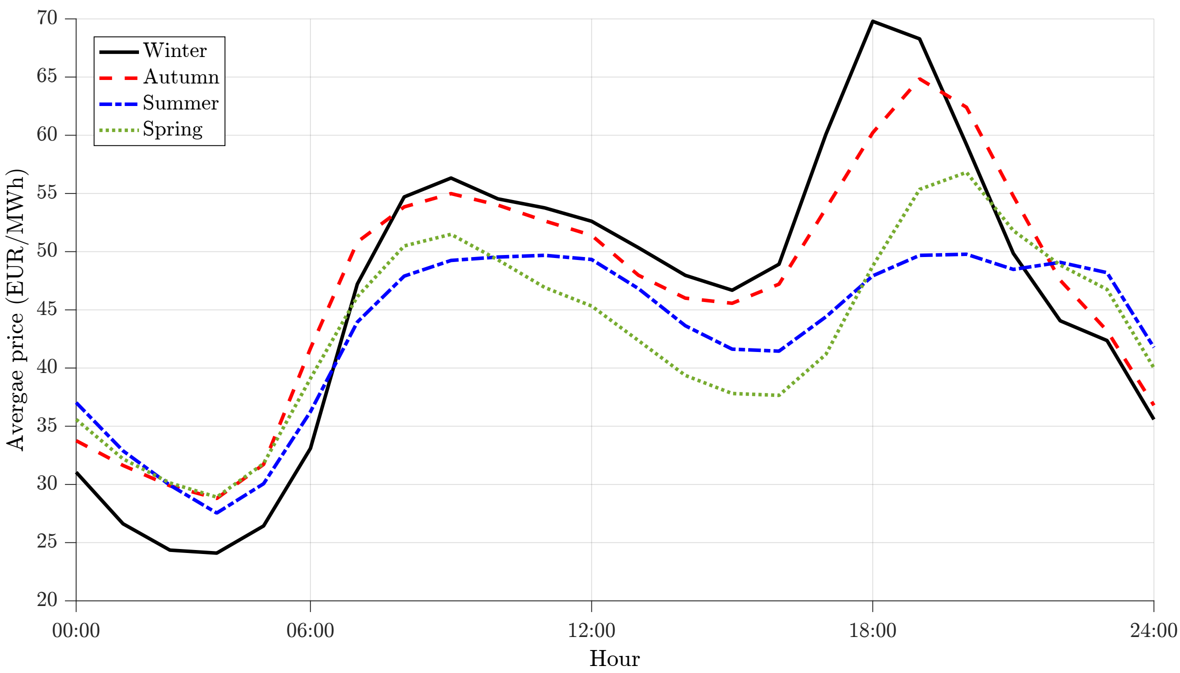

Figure 3.7: Average hourly day-ahead market price in different seasons in Germany in 2012

3.6 Capacity Factor of Variable RES

In this section the capacity factor of variable renewables including PV and wind power plants in the German electricity market is calculated and analyzed. Capacity factor of a generator is the ratio of its actual output over a period of time to its maximum nameplate generation capacity over the same period. The probability distribution function (PDF) of PV and wind capacity factors in Germany in 2012 is presented in Figure 3.8. Besides, the descriptive statistics of wind, PV and a combination of wind and PV capacity factors are displayed in Table 3.2. The average capacity factor of variable RES is approximately 11%, which means that if 100 MW of new capacity of variable RES are added to the market, the average hourly generation from this new capacity will amount to mere 11 MWh. The average capacity factor of wind and PV power plants are 12% and 9%, respectively. Capacity factor of variable RES depends mostly on weather conditions and on the location-dependent renewable generation potential. Additionally, the quality and design of a wind turbine or a PV panel have an effect on the long-term capacity factor of these generation technologies.

	Min	Max	Mean	Standard deviation	Median	Mode
Wind capacity factor	0.004	0.62	0.12	0.10	0.09	0.11
PV capacity factor	0.000	0.63	0.09	0.14	0.003	0.000
Wind+PV capacity factor	0.002	0.40	0.11	0.08	0.08	0.04

Table 3.2: Descriptive statistics of wind and PV capacity factor

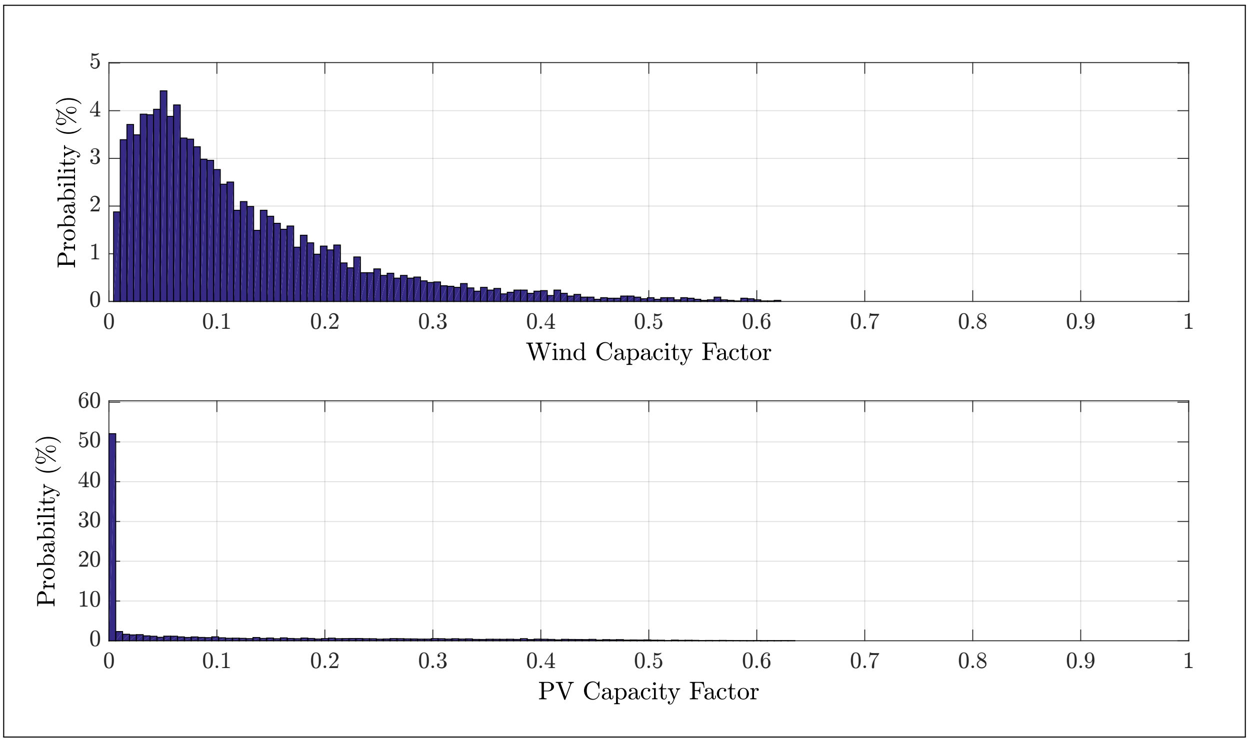

Figure 3.8: Wind and PV capacity factor in Germany in 2012

3.7 Capacity Credit of Variable RES

Capacity credit or capacity value of a generator is the amount of additional peak load that can be served by that generator. The capacity credit of RES is then calculated in order to measure the impact of uncertainty related to the contribution of renewable generation on resource adequacy. In literature, capacity credit is further known as Effective Load Carrying Capability (ELCC). Variable RES contribute less to resource adequacy compared to dispatching generators. The reason for this is the fact that the correlation between variable RES generation and peak demand is much weaker than in case of dispatching generation. Therefore, the electricity market requires additional back-up capacity to meet the target reliability criterion. The key question is then how much dispatching back-up capacity is required to maintain system reliability in the presence of a defined volume of variable renewable capacity.

The approach to calculating the capacity credit of variable RES is discussed in 4.4.4.1. The capacity credit ratio of a generation technology is defined as the ratio of the capacity credit of that generation technology to its installed capacity. It is assumed that PV and wind have a equal share in the generation profile at every year. This study estimates that the capacity credit ratio of variable RES in Germany, which is depicted in Figure 3.9, is equal to 4% in case of a 20% level of variable RES penetration while this ratio decreases to less than 2.3% in case of a 50% level of RES penetration. Therefore, higher shares of RES in the generation profile result in a lower capacity credit ratio of RES. This can be explained by the negligible contribution of PV generators to cover the peak load during cold winter evenings in Germany. Therefore, increasing penetration of both PV and wind generation leads to a lower capacity credit. Results show that the capacity credit ratio of variable RES in Germany is lower than the sum of the average capacity factor of PV and wind generation. Due to the low capacity credit of variable RES in Germany significant amounts of new conventional capacity would still be required in order to maintain the same level of resource adequacy in the electricity system. The electricity system would require additional investment in conventional generation to compensate for the low capacity credit of variable RES.

The capacity credit of variable RES in Germany in long-term has been estimated in several studies [JMN+05], [KMD+11], [HMO+09]. In [JMN+05], the capacity credit of wind in 2003 in Germany is estimated to be between 7% to 9%, while the considered 35.9 GW wind capacity in 2025 would be associated with a capacity credit of only 5% to 6%. The above mentioned study shows that an increasing penetration of variable RES results its lower capacity credit. Results from [HMO+09] compare the capacity credit of wind in several electricity markets around the world. According to that study, capacity credit mainly depends on the specific characteristics of the country such as the characteristics of the demand profile and whether peak load occur in winter or summer. The study by [BGP+06] denotes that by increasing the share of wind from 20% to 50% of peak load in Germany, capacity credit of wind drops from 8% to 5%. According to the calculations in [GPL12], the capacity credit of wind lies between 5.2% to 6.2% of total installed wind capacity for the period from 2008 to 2030, while the capacity credit of PV during the same period is 0% due to the fact that peak load in Germany occurs on a winter evenings.

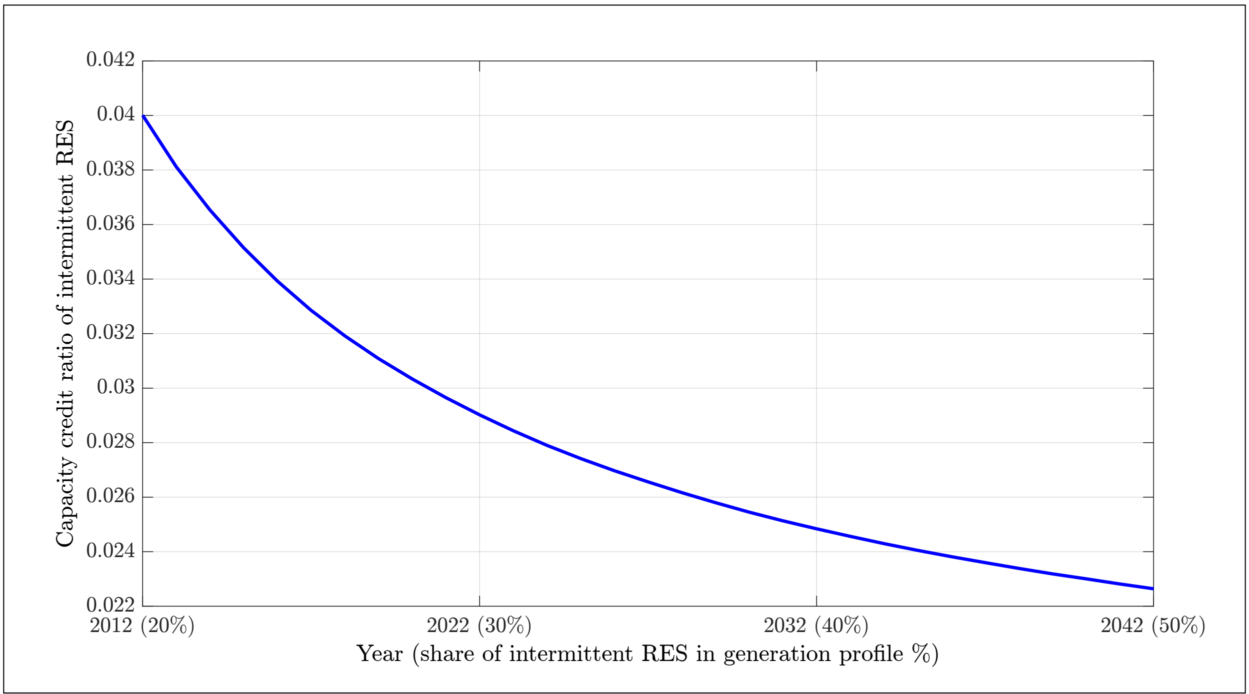

Figure 3.9: Capacity credit ratio of variable RES versus RES penetration

4 Proposed Model Framework

4.1 Introduction

This chapter zooms in on the specifics of the proposed model which is developed to study generation resource adequacy in energy-only markets. The proposed model simulates the operation of the long-term electricity market in order to analyze the impact of different market parameters on the reliability metrics. The model probabilistically evaluates generation resource adequacy in energy-only markets by estimating the expected equilibrium conditions under which suppliers earn adequate average revenue which allows them to recover their total costs and provides enough incentives for new investment in generation capacity. The generation investment problem is formulated with the help of a stochastic optimization framework and the optimal investment in new generation capacity by both risk-neutral and risk-averse investors is determined. The model simulates hourly generation dispatch, generation availability, load profiles, load uncertainty, and demand response in the electricity market. As a result, the model calculates hourly prices, hourly and annual profit for generators, optimal new installed generation capacity in each year, annual demand response utilization and scarcity prices.

The rest of this chapter is structured as follows. First, basic definitions and concepts used in the proposed model are briefly explained. Then, the case study and the main assumptions in the proposed model are described. Finally, the details of different components in the proposed model such as generation, load, investment, demand response and reliability measures are discussed.

4.2 Basic Definitions and Concepts

This section provides a description of the main definitions and concepts used in this chapter.

Markov Chain Monte Carlo Approach – In probability and statistics, the probability distribution function (PDF) of a random variable presents all the properties of this random variable. In case the PDF of a random variable is unknown, several methods can be used to estimate the statistical properties of this variable. Monte Carlo simulation is an approach used to estimate the PDF of a variable by analyzing the random observations or samples of the variable. By obtaining more samples from a random variable, the estimated statistical indexes are more likely to be close to the real values. The statistical indexes of a random variable include the mean, variance, median, mode, skewness, and kurtosis and so on. The uncertainty of a random variable can be represented by a finite set of samples from that variable.

Markov Chain Monte Carlo (MCMC) approach is developed after Monte Carlo simulation in order to simulate the dynamics of a system with uncertainty and random variables. In this study, MCMC method is utilized to model the stochastic evolution of random variables during a time period. A tree structure for the evolution of a random variable during the defined time period is depicted in Figure 4.1. Each node represents a sample from the subset of the sample space at each period. Each branch represents one realization of the random variable and its associated probability. One scenario of the evolution of the random variable consists of a subset of all branches and the probability of that scenario is determined by multiplying the probability of all the branches in that scenario. For instance, the red branches represent one scenario of the evolution of the random variable and the probability of this scenario is calculated in Equation 4.1.

$$P_{scenario} = P_{1A} * P_{2C} * ... * P_{KB} \tag{4.1}$$

KKT conditions – The Karush-Kuhn-Tucker (KKT) conditions are first-order conditions for an optimal solution in a constrained optimization problem. A constrained optimization problem with both equality and inequality constraints is typically formulated as is shown in Equation 4.2.

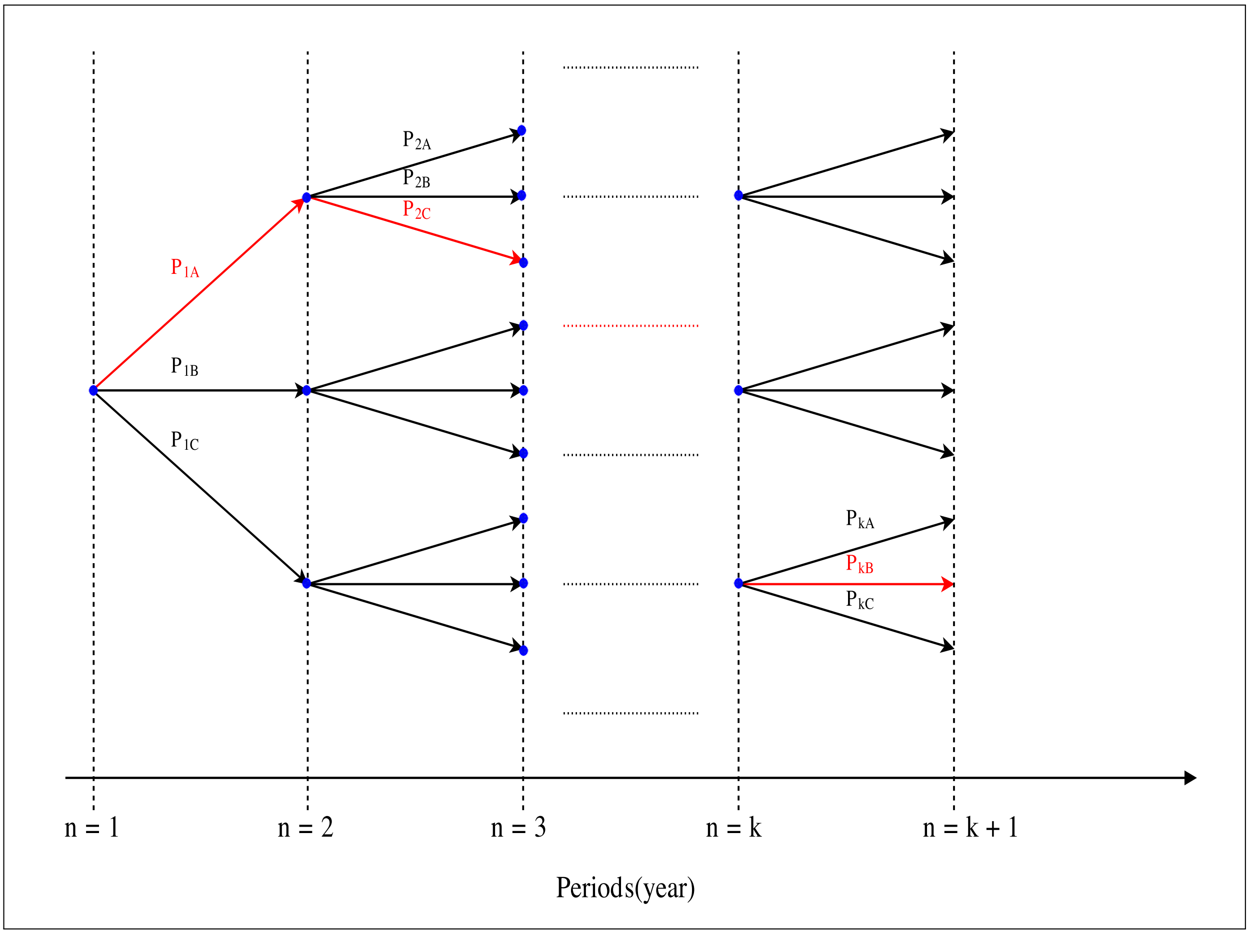

Figure 4.1: Markov Chain Monte Carlo (MCMC) Simulation

$$
\begin{aligned}
&\max f(x) \\
&subject\ to: \\
&g_i(x) = c_i \qquad i = 1, ..., n \qquad (\alpha_i) \\
&h_j(x) \leq d_j \qquad j = 1, ..., m \qquad (\beta_j)
\end{aligned}
\tag{4.2}
$$

In this optimization problem, $f(x)$ is the utility or the objective function, x is the optimization variable while g_i and h_j are the equality and inequality functions, respectively. The variables α and β are the Lagrange multipliers for the constraint equations. The Lagrange multipliers represent the extent of variation in the optimal value of the objective function with respect to small changes in each constraint. By using the KKT conditions, the constrained optimization problem is reduced to the problem of finding a solution for these conditions. The KKT conditions for this general optimization problem are defined in Equation 4.3:

$$\begin{aligned}
&I. \quad && \frac{\partial f}{\partial x_t} - \sum_i \alpha_i \frac{\partial g_i}{\partial x_t} - \sum_j \beta_j \frac{\partial h_j}{\partial x_t} = 0 && t = 1, ..., T \\
&II. \quad && g_i(x) = c_i && i = 1, ..., n \\
&II. \quad && h_j(x) \leq d_j \;\; and \;\; \beta_j \geq 0 \;\; and \;\; \beta_j(h_j(x) - d_j) = 0 && j = 1, ..., m
\end{aligned} \tag{4.3}$$

4.3 Case Study and Assumptions

In this study, the German energy-only market is modeled and long-term generation resource adequacy in this market for a 30-year period from 2012 to 2042 is analyzed.

4.3.1 Data

The required data for modeling and analysis of the German electricity market is collected from different data sources. The day-ahead market prices are provided by European Power Exchange (EPEX) which hosts the day-ahead auctions for Germany. The hourly day-ahead market prices are determined by a uniform price auction at 12 p.m. for every hour of the next day. The actual and day-ahead forecasts of hourly variable RES generation are published by the main transmission system operators (TSOs) in Germany including EnBW Transportnetze, Tennet TSO, Amprion, and 50Hertz Transmission. Hourly load values in the Germany from 2000 to 2016 are published by European Network of Transmission System Operators for Electricity (ENTSOE-E). The data for the unavailability of production and generation units including forced and unforced outages are published by ENTOSE-E.

4.3.2 Main Assumptions

- Perfect Competition: The proposed model assumes that there is a perfect competition in the market. Perfect competition has a specific set of characteristics. All producers sell a homogeneous and identical product, which is electricity. All generators are price-takers and none of them have enough market power to control the market price. All producers, consumers and investors are rational players that aim to maximize their utility or profit in the market.

- Investment Decision: Investors make investment decisions adding new generation capacity to the market every year. Investment decision-making is a centralized decision-making structure. Investors have complete information about the ongoing and previous investment decisions for new generation capacity, i.e. about the capacity already installed as well as about the new generation capacity under construction. Investors are rational market players that decide to invest in new capacity if and only if their new investment is expected to be profitable. New generation capacity can be added in arbitrary small increments and there is no cap or floor for its volume. It is assumed that retired generators are always replaced in time with new generation capacity, thus, a possible delay between the retirement of old generators and the replacement with new generators is not considered in the model. It is assumed that there is some construction time between the investment decision and the time that the new generation capacity becomes available to generate electricity. This delay due to construction for new CCGT power plants is assumed to be three years.

- Overcapacity: Currently, there is a considerable overcapacity in generation capacity in the German electricity market. Due to this overcapacity, conventional generators are utilized at a low capacity factor. In the proposed model, the initial overcapacity in the German electricity market is assumed to be 7% of peak load in 2012. The assumed overcapacity is considered to be effective installed capacity, meaning that it is fully available during the year.

- Renewable Generation Capacity: The proposed model considers generation from variable RES to be an exogenous input variable, which affects the model without being affected by it. The share of solar and wind generation is increasing linearly from 20% in 2012 to 50% of the total electricity consumption in 2042. This assumption is made based on the defined German policies and targets meant to increase RES penetration.

- Type of New Generation Capacity: New installed capacity is assumed to be represented by combined-cycle gas turbine (CCGT) power plants for two reasons. First, gas-fired power plants have a lower investment cost as compared to other conventional generators. Since a higher share of renewables leads to a lower utilization factor of all conventional generators, a less capital-intensive technology is more likely to manage to recover its capital costs as compared to conventional generation technologies. Second, an increasing share of variable renewables causes more fleet-wide variability in the generation profile and the required backup capacity in this case should be able to provide a very fast response to a highly variable generation profile. Among all dispatching generators, gas-fired power plants have a faster ramp-up rate, which can be achieved in the matter of few minutes. Therefore, gas-fired power plants are the best choice among conventional generation technologies for providing the required backup capacity. Among different types of gas-fired power plants, CCGT power plants are considered to be the main generation technology of new additional capacity. The estimated cost of new entry (CONE) is the amortized fixed cost of new generation capacity, which is estimated to be 59,500 €/MW.yr for new CCGT power plants.

4.4 Proposed Model

4.4.1 Introduction

In this section, a probabilistic framework is proposed to model the reliability and generation resource adequacy in electricity markets. The proposed probabilistic framework, which complements already existing deterministic approaches, is required to address significant changes in the electricity sector, which result a high level of uncertainty in the system. These changes include growing shares of variable RES such as solar and wind power and increasing penetration of flexibility on both supply and demand sides such as small-scale storage facilities and demand response. These factors in addition to other uncertainties such as annual demand growth rate, long-term fuel prices and generation resource mix variations are posing higher uncertainty to the electricity markets. Besides, resource adequacy considerations become critical only during rare circumstances of an unusually high load or limited supply. As a consequence, a probabilistic framework is needed in order to examine a full range of potential reliability outcomes and capture wide distributions of possible generation and load uncertainties. The proposed model is only focused on the generation resource adequacy and does not consider other types of reliability issues caused by transmission and distribution outages.

In 2.6, a literature review of the existing generation investment planning models has been provided. The proposed model builds upon previous existing models in a number of ways. First, the model uses a stochastic dynamic optimization framework to find the optimal level of new generation capacity in risk-neutral and risk-averse investment decision making processes. The model estimates the expected profitability of new generation capacity during its lifetime. Second, the proposed model considers the capacity credit of renewables as one of the main sources of uncertainty, which is highly correlated with resource adequacy in electricity markets. The capacity credit of renewables is determined by evaluating the probability density function of generation from variable RES and using the Monte Carlo sampling approach. Third, the model calculates the loss of load probability (LOLP) by estimating the probability distribution function of supply and demand. Fourth, the proposed probabilistic framework makes it possible to conduct both reliability and economic analysis of the impact of the investment risk, demand response and scarcity prices on the long-term generation resource adequacy in energy-only markets.

The main features and limitations of the proposed model are described in the following section. The main features include:

- The model considers the main generation uncertainties correlated with resource adequacy, including the capacity credit of variable RES and forced outage of conventional generators.
- The model considers the main load uncertainties correlated with resource adequacy, including the load forecast error, demand growth rate and weather-related load uncertainty.
- The model provides an estimation of the economically optimal reserve margin at which point the total generation cost of electricity system is at its minimum. Besides, LOLP in a given year is calculated by estimating the probability distribution function of generation and demand.
- The model simulates two types of economic and emergency DR with a range of dispatch prices and estimates the optimal volume of DR required to ensure resource adequacy. The

model evaluates the resource adequacy value of DR by considering dispatched energy and dispatch-hour limitations.

The main limitations of the proposed model include:

- The model does not consider other sources of generation uncertainty such as long-term fuel price and marginal cost variations for each generation technology and generation uncertainty related to non-variable RES such as hydro and biomass. Besides, the model considers a single bidding price for power plants with a similar generation technology, e.g. the bidding price of all CCGT plants is the same price of 70 €/MWh.

- In the long run retired power plants will be replaced by new ones with a similar generation technology. The calculation of optimal electricity generation cost performed in the model, however, is based on the assumption of the continued existence of the current power plant set.

- The model simulates DR without considering any constraints with respect to whether or not DR can be dispatched in consecutive hours or days. Besides, it is assumed that the DR activated during low reliability periods would only be shifted to off-peak periods. In reality, the activated DR on rarer occasions may also be shifted to medium-peak or high-peak periods, which is however out of the scope of this study. In the present model, DR is activated in response to high electricity prices or system reliability events and the dispatch price of DR is assumed to be higher than the bidding price of marginal producers in the market. Some types of DR, e.g. DR provided by electric vehicles, may however be offered at lower prices, the fact not specifically regarded in the model.

- Cross-border electricity trade can play an important role in fulfilling national generation resource adequacy criteria of a country. However, this model does not consider the electricity import and export between Germany and the neighboring countries.

4.4.2 Model Description

The proposed stochastic dynamic model evaluates the resource adequacy conditions by simulating the generation availability, load uncertainty, and demand response in energy-only markets. The aim is to provide a probabilistic framework in order to study the ways in which an energy-only market design provides incentives for risk-neutral and risk-averse investors to construct new generation capacity. Markov chain Monte Carlo (MCMC) method is applied to a large number of generation and demand scenarios in order to fully explore possible resource adequacy outcomes. Since resource adequacy presents a concern during peak load periods and scarcity events, the proposed model only considers the uncertainties which are correlated with such peak load events. To this aim, the capacity credit of renewables and forced outage of conventional generators are considered as the main sources of uncertainty on the generation side. Additionally, load forecast error, weather-related load uncertainty and demand growth rate are considered on the demand side as sources of uncertainty. Generation and load uncertainty modeling is consistent with the historical data in the German electricity market, which makes it possible to properly capture the resource adequacy conditions in the analyzed market. On the supply side, the probability distribution of the capacity credit of renewables is calculated and 100 Monte Carlo samples of generation from RES for each year are utilized. Furthermore, the uncertainty of conventional generation outages is modeled by drawing 10 samples from the distribution of hourly forced outages for each year. On the demand side, the model incorporates 30 scenarios from the histogram representing the demand growth rate and mutual probability distribution of uncertainty due to weather and load forecast error.

The model dynamics for the analysis of long-term resource adequacy is structured as follows. For each year, the model determines several hourly generation and load scenarios by incorporating the uncertainty of supply and demand. Then, hourly market prices and revenues are calculated for all generation technologies in all generation and load scenarios. The annual profit for each generator is determined after subtracting the annual amortized fixed cost from the annual revenue of that generator. Optimal investment in new generation capacity is then made by investors based on their forecasts of future profits from new generation capacity. New generation capacity is added to the market after the assumed delay due to construction and the total installed capacity for the next years is finally updated. This algorithm continues for the remaining years and the optimal new installed capacity is determined for all years.

Figure 4.2 shows the sequence steps related to annual investment decision-making in the proposed model. The algorithm can be summarized as follows. First, the generation and load time series in year i is forecasted by considering the uncertainties in the generation and load side. Then, the market is cleared and hourly prices and annual profit for all generators in the i-th year are determined. Then, the optimal amount of new additional generation capacity which will be added to the generation profile in the i-th year is determined. All these steps are repeated for the $i+1$-th year until the algorithm reaches the last year. The details of proposed energy-only market model are discussed in the following subsection.

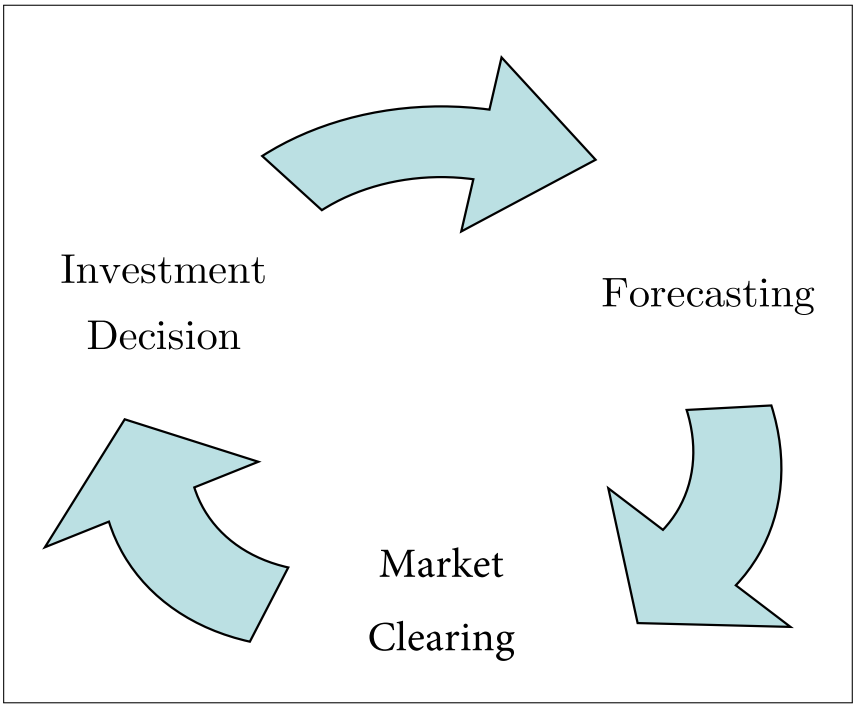

Figure 4.2: Simulation algorithm flowchart

4.4.3 Model Structure

The model considers the variability and uncertainty associated to generation and demand at each year by implementing a Monte Carlo analysis to develop a limited number of independent samples for generation and demand time series at each year. The number of samples should be large enough to capture the wide range of the probability distributions associated to the generation and load uncertainties. Each sample (realization) of available generation time series at year i is represented by G_i^k and the probability of that sample is denoted by p_k. Besides, each sample of demand time series at year i is represented by D_i^j and the probability of that sample is denoted by p_j. The time series of G_i^k and D_i^j which consist of hourly values over each year are represented in Equation 4.4.

$$\begin{aligned} G_i^k &= [G_i^k(1), G_i^k(2), ..., G_i^k(8760)] \\ D_i^j &= [D_i^j(1), D_j^i(2), ..., D_i^j(8760)] \end{aligned} \tag{4.4}$$

S_i is the optimal new generation capacity which will be added to the generation capacity in year i. The investment decision to build new generation capacity S_i has been made at year $i - \tau$, while τ is the time delay between an investment decision and the time when new generation capacity becomes available to operate in the market. r denotes the generation technology including renewables, nuclear, coal, lignite, gas power plants and demand response. c_r and f_r denote the short-term marginal cost and annual amortized fixed cost of each generation technology, respectively.

The optimal new generation capacity S_i for each year is determined according to steps presented in Figure 4.3 which is shown in page 78. This figure demonstrates the simulation flowchart consisting of the main calculation blocks in every simulated year. The long-term operation of the proposed model is summarized in the following steps:

Step 1. Beginning from year $i - \tau$, the available generation time series for year i is forecasted by considering the additional RES generation capacity as an exogenous input and the uncertainty from capacity credit of RES and forced outage of conventional generation. The generation uncertainty modeling is explained in 4.4.4.

Step 2. The demand time series for year i is forecasted by considering the uncertainty from demand growth rate, load forecast error and weather-related load uncertainty. The demand uncertainty modeling is explained in 4.4.5.

Step 3. In the market clearing step, hourly market price and profit for all generators are determined. The hourly market prices are determined by a uniform price auction. $G_i^k(h)$ is total available generation volume in h-th hour of year i which is derived from k-th sample of generation time series. Similarly, $D_i^j(h)$ is demand volume in h-th hour of year i which is derived from j-th sample of demand time series. The intersection of supply and demand curves results the $P_i^{k,j}(h)$ which is the market price in h-th hour of year i which is derived from the intersection of $G_i^k(h)$ and $D_i^j(h)$. If the hourly available generation is greater than hourly demand, the market price is equal to the marginal cost of the last generation unit needed to serve hourly load. The marginal cost of each generation technology r is defined by c_r. If the load exceeds the total available generation, demand response $DR_i(h)$ is activated and the market price is then equal to the bidding price of demand response at each hour c_{DR}. In the event of the demand still being higher than the sum of generation and demand repose capacities, load shedding occurs and the market price rises up to the level of the price cap (CAP). The price formula is given in the equation 4.5.

$$P_i^{k,j}(h) = \begin{cases} c_r & G_i^k(h) \geq D_i^j(h) \\ c_{DR} & D_i^j(h) - DR_i(h) \leq G_i^k(h) < D_i^j(h) \\ CAP & G_i^k(h) < D_i^j(h) - DR_i(h) \end{cases} \tag{4.5}$$

The average price at each hour h of year i is denoted by $E(P_i(h))$ and calculated by taking an average over all the demand and available generation samples. The average price is formulated in the equation 4.6.

$$E(P_i(h)) = \sum_k \sum_j p_k \; p_j \; P_i^{k,j}(h) \tag{4.6}$$

Step 4. As the average hourly market prices are determined, the annual contribution margin and profit for each generator can be calculated. Contribution margin for each generator is the difference between the total sales revenue and total variable costs. $M_{i,r}$ is the annual contribution margin of generator r in the year i and is defined in the equation 4.7. c_r is the marginal cost of generator r and $Q_{i,r}(h)$ is the quantity of sold electricity by that generator in h-th hour of year i.

$$M_{i,r} = \sum_h \left(\left(E(P_i(h)) - c_r \right) Q_{i,r}(h) \right) \tag{4.7}$$

The annual profit for each generator is calculated by deducting the annual amortized fixed cost for each generator from the annual contribution margin of that generator. The profit calculation for generator type r at year i with the installed capacity K_r and annual amortized per-unit fixed cost of F_r is given in the equation 4.8.

$$\pi_{i,r} = M_{i,r} - F_r\, K_r \tag{4.8}$$

Step 5. In this step, the optimal new generation capacity which will be added in year i and maximizes the total surplus in that year is determined. According to the total surplus optimization, the optimal volume of investment in new generation capacity should satisfy the equilibrium 4.19. The optimal new generation capacity will be added to the generation profile in the year i and the overall installed capacity in that year will be updated. The details of optimal investment decision making and total surplus maximization is explained in 4.4.7.

Step 6. The same process from step 1 to 5 will be executed for the next year. This procedure is thus repeated for the whole period defined in the analysis, i.e. from 2012 to 2042.

4.4.4 Generation Modeling

The generation simulation model includes hourly generation from renewables and conventional generation technologies as well as their economic characteristics such as short-term and long-term marginal costs, life-time, and availability of each generation technology. The supply curve consists of different electricity generation technologies such as renewables, nuclear, lignite, hard coal, and gas-fired power plants. As all generation technologies are sorted to form the supply curve according to their short-term marginal cost, the supply curve is also called the merit order curve. A typical merit order in the German electricity market is depicted in Figure 4.4.

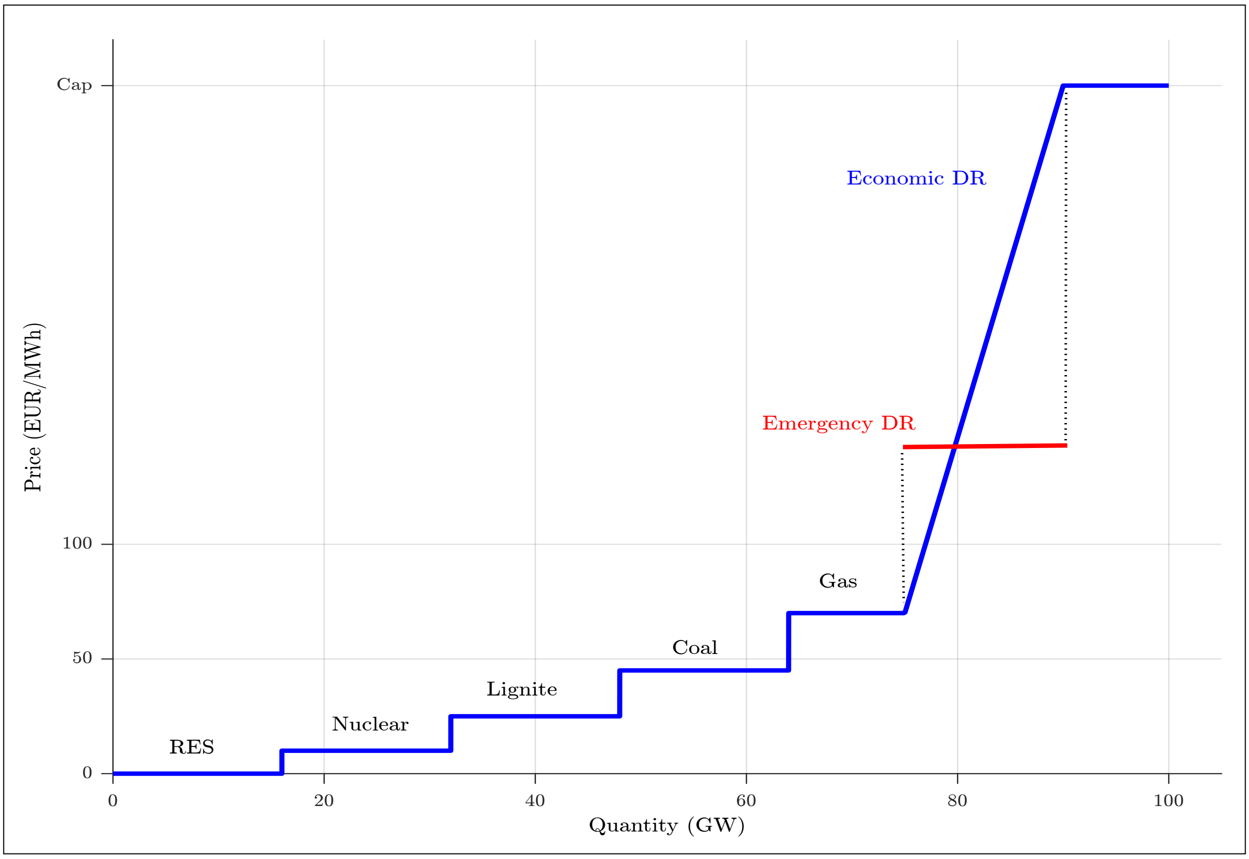

Figure 4.4: A typical merit order curve with demand response

Hourly generation data from all generation technologies is simulated for the period from 2012 to 2042. The installed capacity of renewables and CCGT power plants increases each year. As already mentioned, incremental renewable capacity is an exogenous input in the model. At the same time, the new generation capacity in the form of CCGT power plants, which is determined by investors, is added to the installed generation capacity every year.

A major component of a resource adequacy analysis is modeling of generation uncertainty each year in order to examine a full range of potential reliability outcomes. Since reliability events occur only during low generation and high load events, the model should consider the uncertainties that have higher correlation with reliability events. In this study, the main sources of generation uncertainty proposed in the present model in order to evaluate resource adequacy are:

- Capacity credit of variable renewables
- Forced outage of conventional generation

4.4.4.1 Capacity Credit of Variable Renewables

As resource adequacy becomes critical during peak load hours, one of the main uncertainties in the resource adequacy analysis is the contribution of variable renewables to generation during peak load periods since RES intermittency can have an impact on resource adequacy. Capacity credit of renewables is the amount of renewable generation which is available during peak load or the amount of additional peak load that can be served by renewables [KMD+11]. In other words, capacity credit of renewables is equal to the amount of conventional resources which can be replaced by the renewable generation while keeping system reliability unchanged and thus unaffected. Capacity credit is measured in terms of the installed capacity of variable RES. Understandably, their contribution to resource adequacy is lower than that of dispatching generators as generation from variable RES has a much weaker correlation with peak demand than does dispatching generation. Therefore, the electricity market requires an additional back-up capacity in order to meet the targeted reliability criterion.

Several statistical approaches are proposed to calculate the capacity credit of wind and PV generation in [KMD+11], [HPRT08], [Coz12] and [CK12]. In this study, the approach applied to calculating the capacity credit of renewables is based on the one proposed in [CK12]. This approach calculates the capacity credit of variable renewables as the difference between the peak load and peak residual load in each year as depicted in Figure 4.5. Residual load is then derived by subtracting variable renewable generation from hourly load values.

The calculation using the chosen approach is performed in several steps. First, a data set including the time series of hourly wind and PV generation and hourly load generation are clustered as is shown in Figure 4.6. Wind (PV) capacity factor denotes the ratio of hourly wind (PV) generation to the installed capacity of wind (PV) and load factor is the ratio of hourly load to the annual peak load. Time series are clustered into high and low values by comparing them with the mean value of each time series. The histograms of wind and PV generation during periods of low and high demand are depicted in Figure 4.7 and Figure 4.8, receptively. These histograms are derived for each year by incorporating the PV, wind generation and load values for the year in question.

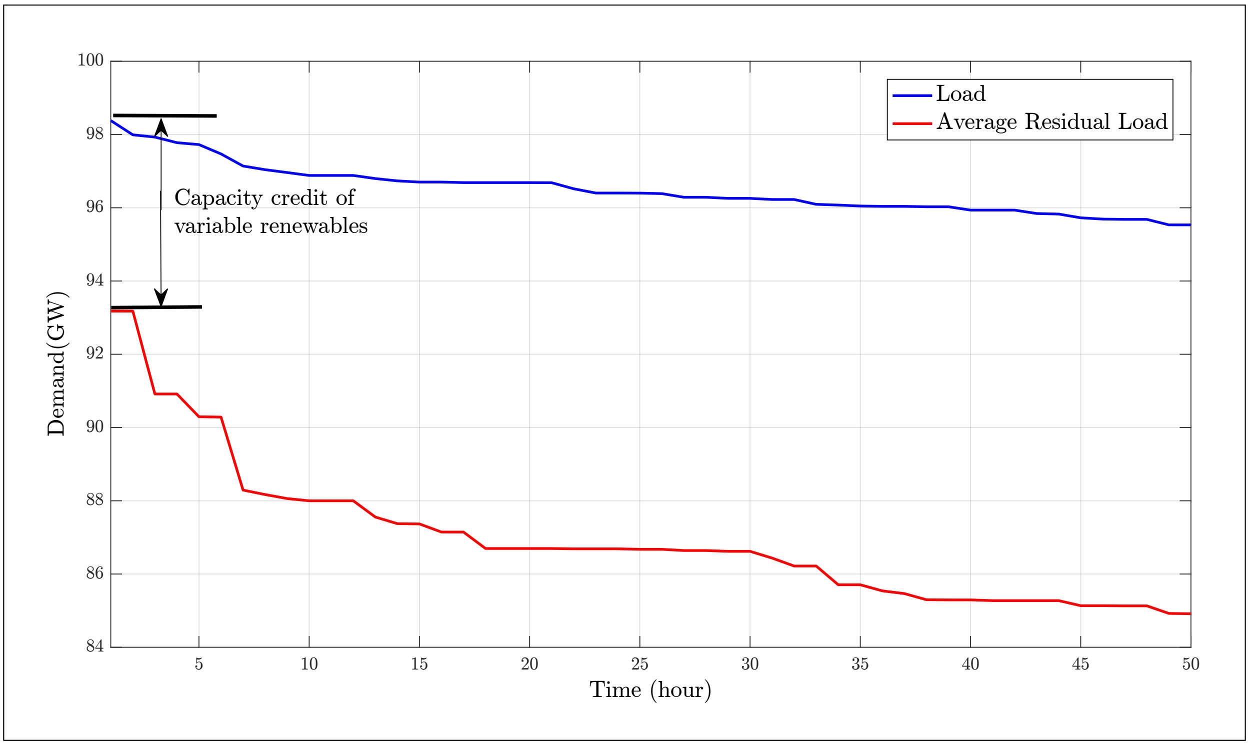

Figure 4.5: Calculation of the capacity credit of renewables by load and residual load curves

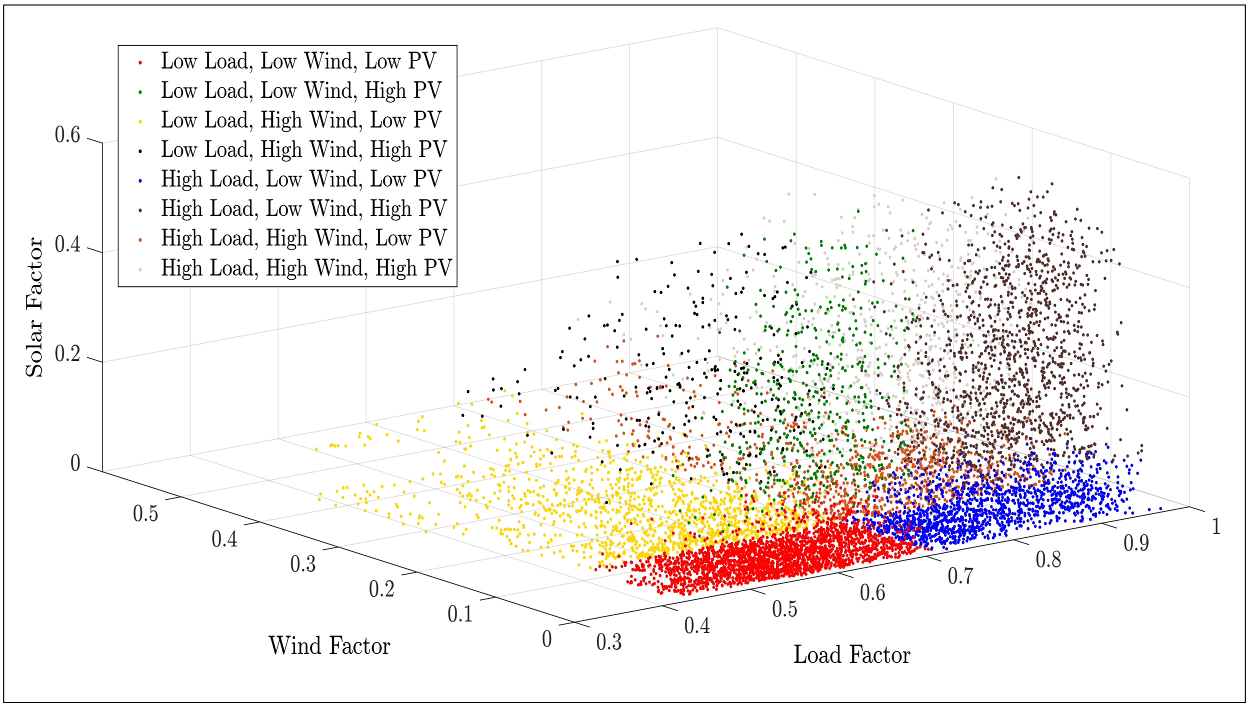

Figure 4.6: Load, wind and PV capacity factor clustering

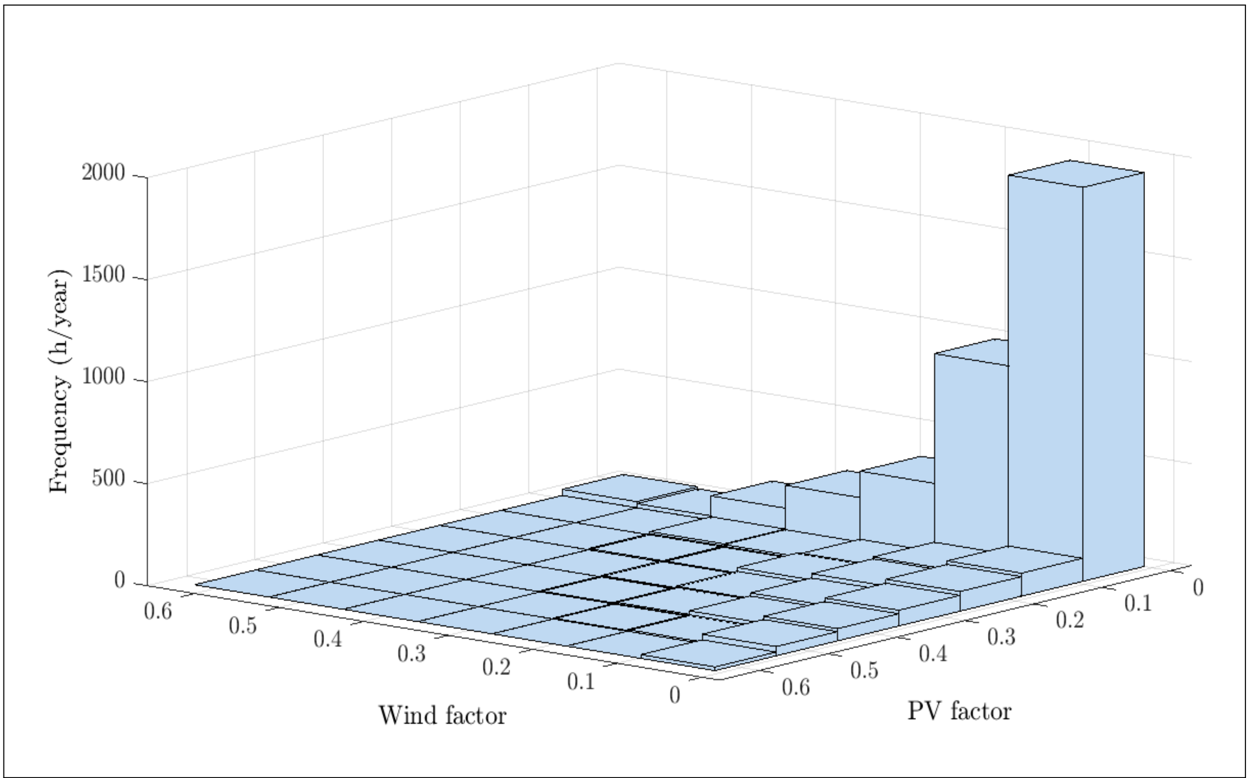

Figure 4.7: Wind-PV generation factor histogram in low demand

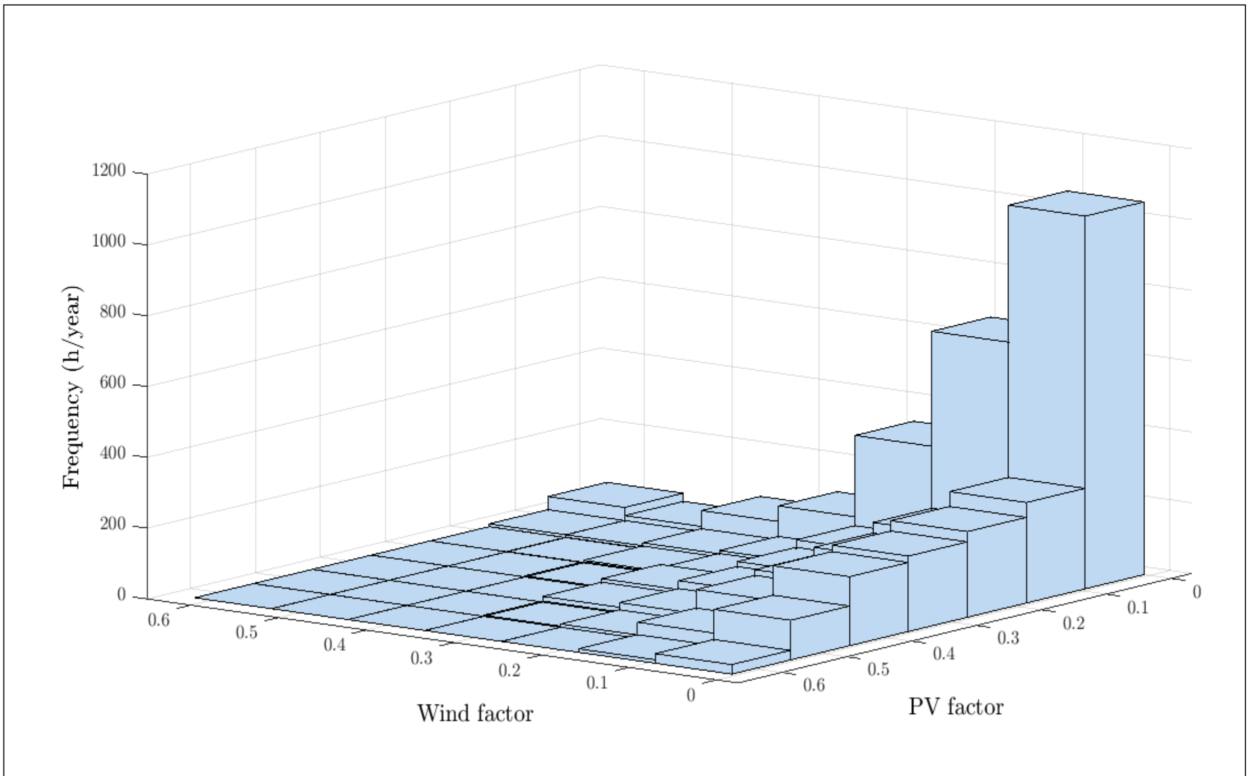

Figure 4.8: Wind-PV generation factor histogram in high demand

Consequently, the model incorporates 100 independent Monte Carlo (MC) samples of wind and PV generation and load values for each year. The capacity credit is calculated as the difference between the average of 10 highest load hours and the average of 10 highest residual load values. By analyzing the MC 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 Figure 4.9. The mean values of the annual capacity credit are shown with the red line. Figure 4.10 shows the ratio of capacity credit to the installed capacity of variable renewables in each year. This ratio decreases when the penetration level of variable RES increases. The capacity credit ratio of renewables lies in the range between 2% to 4% of the total installed capacity, which is lower than the average capacity factor of both PV and wind.

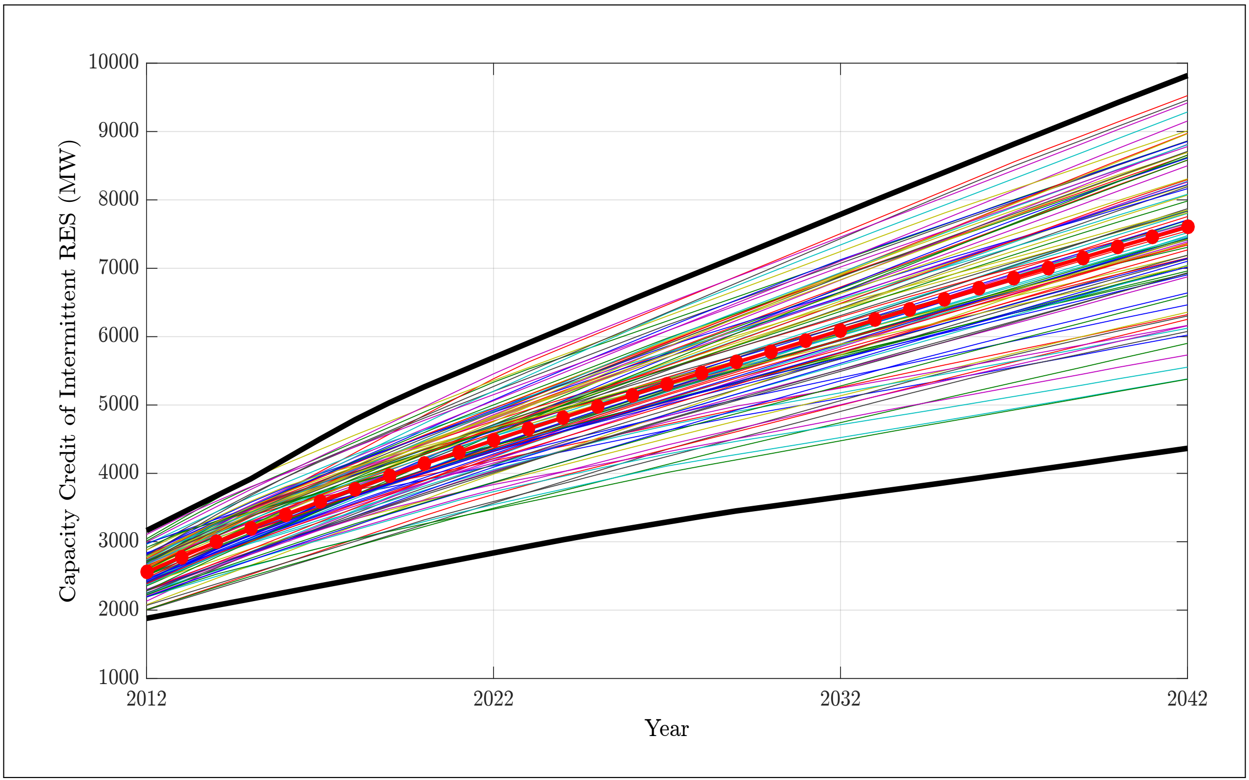

Figure 4.9: Monte Carlo samples for capacity credit of intermittent RES

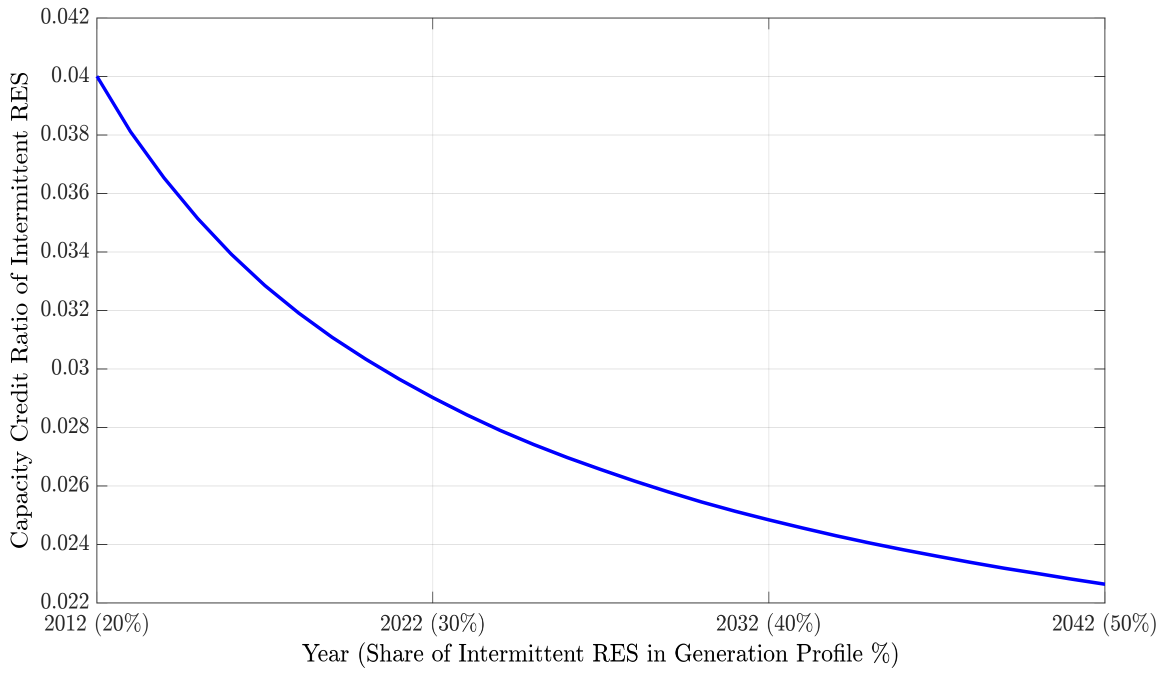

Figure 4.10: Capacity credit ratio of intermittent RES versus the RES penetration

4.4.4.2 Forced Outage of Conventional Generation

Another major source of generation uncertainty highly correlated with resource adequacy is forced outages by dispatching generators. There are two types of outages when it comes to conventional dispatching generators, planned outages and forced outages. Planned outages can be postponed by definition and are therefore usually scheduled during periods of low demand. Forced outage is a partial or full outage of a generation unit that is delayed over the reasonable threshold of, for instance, 48 hours. As resource adequacy is critical only during peak load periods, it is only the uncertainty of forced outages that is considered in the proposed model. The model simulates forced outage of conventional generators stochastically by using Monte Carlo sampling technique. The histogram of the partial and full forced outages in the German electricity market in 2012 is depicted in Figure 4.11. The forced outage of conventional generation grows proportionally with the installed capacity of conventional generators each subsequent year. The proposed model incorporates 10 Monte Carlo samples from the hourly forced outage histogram for each year.

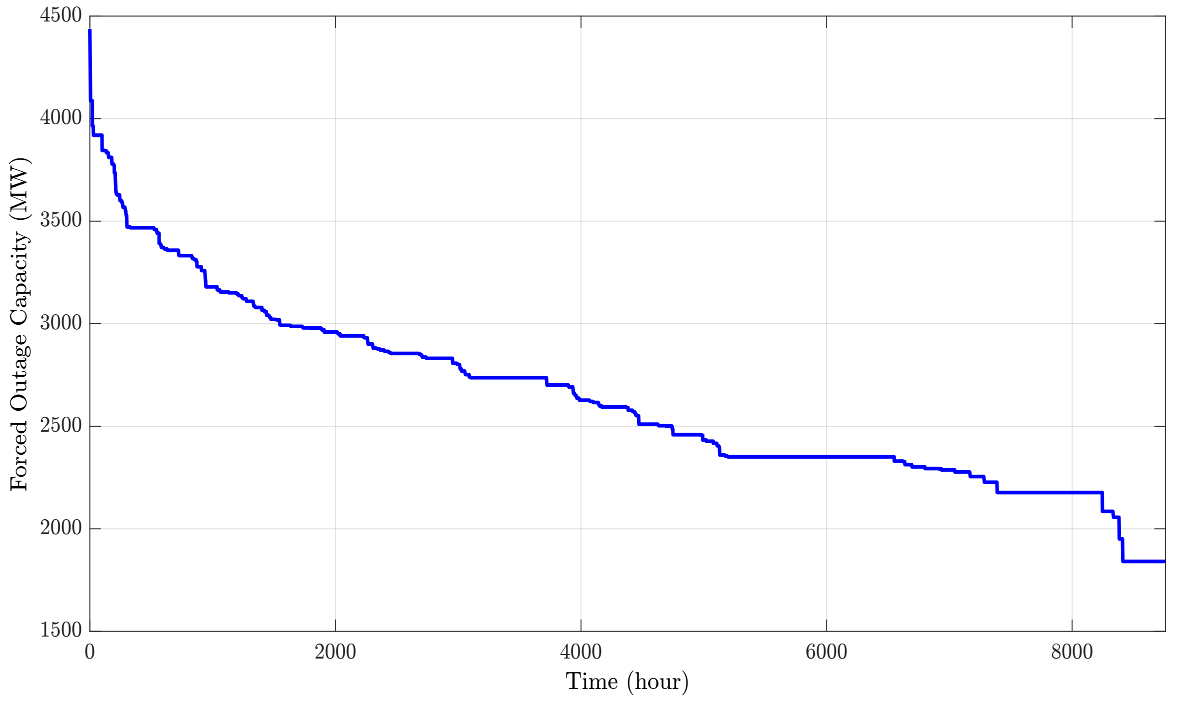

Figure 4.11: Histogram of the forced outage by conventional generation

4.4.5 Load Modeling

Load is modeled as the load-duration curve with hourly load values across each year. The main sources of uncertainties in load modeling are considered to be:

- Weather-related load uncertainty
- Load forecast error
- Rate of demand growth

Similar to generation uncertainty modeling, only those uncertainties that have a high impact on the resource adequacy criteria are taken into account.

4.4.5.1 Weather-related Load Uncertainty

The actual load may be different from the foretasted load due to weather-related uncertainties in load prediction since the weather cannot be predicted exactly but changing weather conditions may change the consumption behavior of electricity consumers. Weather-related uncertainty in load values is modeled with a normal distribution with mean zero and a standard deviation σ_w, which is assumed to be 2% of the peak load in each year. Based on the normal probability distribution, the probability of extreme weather conditions is relatively low.

4.4.5.2 Load Forecast Error

Load forecast error is another main source of uncertainty in load modeling which has a direct impact on the resource adequacy condition. Load forecast error can result from uncertainties in population growth, economic development, energy efficiency policies and other parameters. Load forecast error is modeled separately from weather-related load uncertainty since weather-related load uncertainty is independent from the forward planning period while load forecast error increases with the extension of the forward planning period. Forward planning period is the construction lead time for new generation capacity, which investors have to take into account in their investment decision-making. Non-weather load forecast error is modeled as a normal distribution with mean zero and a standard deviation σ_f, which is assumed to be 0.2% for a three-year forward planning period. As in this model the new investment is assumed to be made in gas-fired power plants, the approximate construction lead time for new gas power plants is assumed to be 3 years.

The sum of weather-related uncertainty and load forecast error is given in the equation 4.9. D is the real load value and m_D is the average forecasted load. As the sum of two independent and normally distributed random variables results in a normally distributed random variable, the load is modeled as a random variable with normal probability distribution.

$$D \sim N(0, \sigma_w) + N(m_D, \sigma_f) = N(m_D, \sqrt{\sigma_w^2 + \sigma_f^2}) \tag{4.9}$$

4.4.5.3 Growth Rate of Demand

The load duration curve for Germany in 2012 is depicted in Figure 4.12. Load is assumed to increase each year with an annual demand growth rate r_n, which is a stochastic variable derived from a triangular distribution with a minimum of 0%, a maximum of 2% and a mode of r_{n-1}. Triangular distribution reflects the tendency towards cycles in general economy, which creates related cycles in the long-run load scenarios [DVH08]. Hourly load values for a given year are derived by multiplying hourly load values from the previous year and the growth rate of demand for that year. The hourly load at the h-th hour from year n is calculated according to the equation 4.10.

$$D_h^{n+1} = (1 + r_n)\, D_h^n \tag{4.10}$$

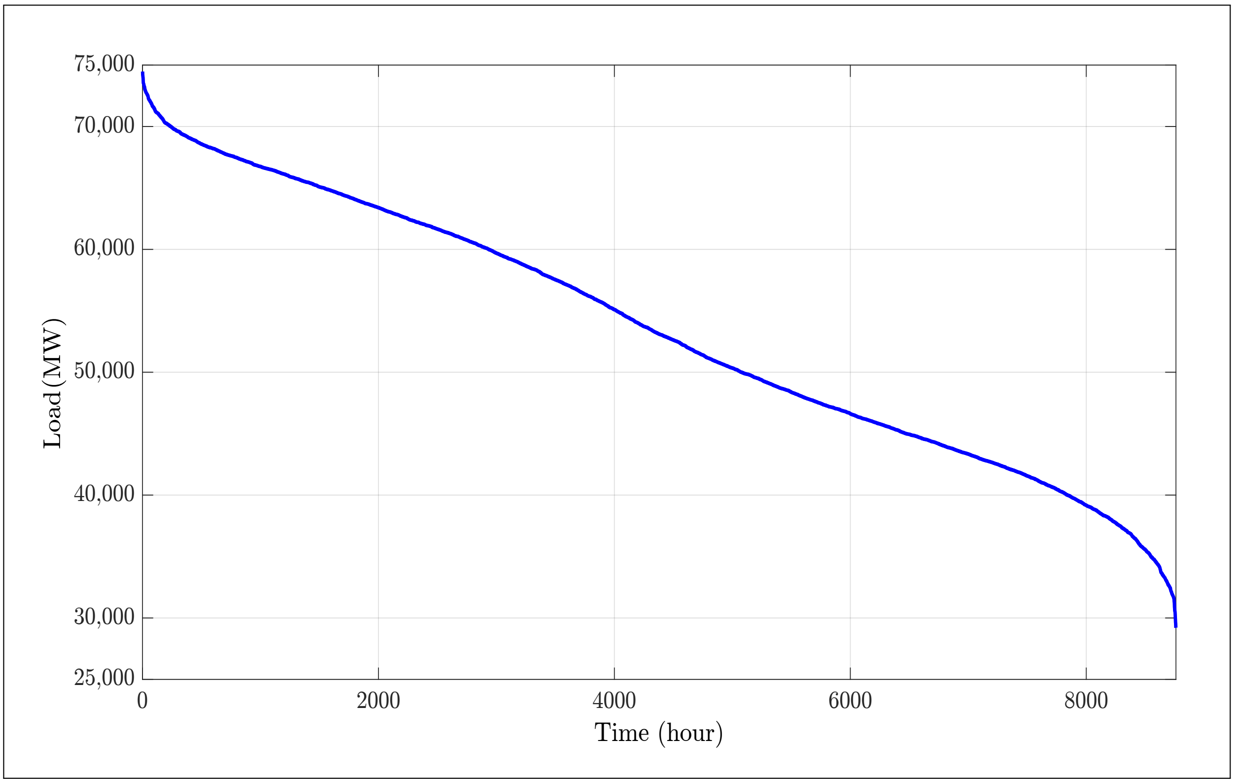

Figure 4.12: Load-duration curve for Germany in 2012

4.4.6 Demand Response Modeling

DR resources in Germany are typically utilized during months when low temperatures lead to a rise in electricity consumption. The peak load in Germany occurs mainly due to the increased need for space heating. For the purpose of this study, DR is defined as an action by consumers to reduce their electricity consumption in response to an event such as high price or low reliability. This definition of DR implies the following features including: (i) DR is dispatchable and event-based and not a permanent load reduction. (ii) DR would be activated in response to the electricity prices or system reliability. (iii) The same amount of activated DR during low reliability period would be shifted to off-peak or high reliability periods. (iv) The restrictions on availability, call hours and dispatch volume of DR are considered. (v) The availability of DR resources during consecutive hours or days is not considered. Following these features, DR is classified into two main categories: incentive-based DR (or emergency DR) and price-based DR (or economic DR). A typical merit order curve, including both the economic and emergency demand response in the German electricity market, is depicted in Figure 4.4.

Emergency or reliability-based DR is activated in response to the system reliability and contributes to resource adequacy by increasing the reserve margin during supply scarcity. Emergency DR programs provide incentive payments to customers for load reductions during emergency conditions rather than based on market prices. The variable cost or dispatch price of emergency DR from industrial technologies highly depends on the type of industry and may differ significantly even within one industrial sector [TL15], [PB11]. In this study, a wide range of dispatch price for emergency DR from 100 €/MWh to 2000 €/MWh is considered and the sensitivity of resource adequacy conditions to the dispatch price of emergency DR is evaluated.

In contrast to emergency DR, the suppliers of economic or price-responsive DR bid into the energy market at a price that reflects consumers' willingness to shift their load. The capacity of economic DR is modeled in a way similar to a dispatching generator with a bidding price ranging from the highest bidding price of gas-fired power plants up to the price cap. It is assumed that the interrupted load in both economic and emergency DR programs is shifted to the off-peak period.

In this study, a wide range of long-term fixed cost for DR from 1 €/KW.yr to 20 €/KW.yr is considered. This assumption is based on the existing literature on the estimation of DR fixed cost. In [BLT11] and [STB09], the long-term fixed cost of smart appliances in EU is calculated by estimating the costs incurred by households that participate in use of smart appliances. This cost includes the annualized investment cost for smart appliances, annualized operational cost for provision of smart functionality by appliance and annualized cost for control infrastructure. The authors define the upper and lower cost scenarios in 2010 and 2025 in order to cover the range of expected costs. That study shows that the long-term fixed cost of smart appliances is in the range from 0.2 to 16 €/KW.yr in low cost scenario and the range from 0.5 to 32 €/KW.yr in high cost scenario. The average annual cost of DR appliances in low cost and high cost scenarios in 2025 are approximately 10 €/KW.yr and 19 €/KW.yr, respectively.

4.4.7 Optimal Investment

4.4.7.1 Basic Definitions

The aim of a total surplus (social welfare) optimization problem is to find the generation rate and the consumption rate at which the total economic surplus for both generators and consumers is at its maximum. Basic parameters required to formulate an optimization problem for surplus maximization in generation investment are described below.

- Q is the amount of electricity consumption measured in MWh.
- $U(Q)$ is the utility function which represents the surplus that generators and consumers receive from producing or consuming electricity. The utility value is measured in €.
- $C(Q)$ is the cost function which represents the cost of electricity generation and is measured in €.
- r is the generation technology such as coal power plants, gas-fired power plants, etc.
- K_r is the installed capacity of each generation technology measured in MW.
- c_r is the short-term marginal cost or the variable cost of electricity generation by each generation technology measured in €/MWh.
- f_r is the hourly amortized fixed cost of each generation technology in €/MWh.
- P is the market clearing price measured in €/MWh.

According to these parameters, the cost function for each generation technology is defined in equation 4.11.

$$C_r(Q_r, K_r) = c_r Q_r + f_r K_r \tag{4.11}$$

4.4.7.2 Investment Model

In this section, the optimal generation investment is calculated by estimating the expected profitability of new installed generation capacity using a stochastic approach. The proposed model specifies each simulation hour with two variables k and j, with associated probabilities p_k and p_j. k represents each random sample (realization) from available generation time series and the probability of that sample is denoted by p_k. The variable j represents each sample of demand time series and the probability of that sample is denoted by p_j. As the volume of available generation and demand at each hour are independent from each other, p_{kj} is equal to the multiplication of p_k and p_j and defined as $p_{kj} = p_k.p_j$.

The social welfare optimization problem is defined in the equation 4.12 and the constraints are given in the equations 4.13 and 4.14. The constraints indicate that the generation volume of each generator lies within the range between zero and the full load generation capacity of that generator. The Lagrange multipliers α_{ikj} and β_{ikj} are associated to each constraint.

$$\max \sum_k \sum_j p_{kj} \left(U_{kj} \left(\sum_r Q_{ikj} \right) - \sum_r C_r(Q_{rkj}, K_r) \right) \tag{4.12}$$

subject to:

$$Q_{rkj} \leq K_i \quad (\alpha_{rkj}) \tag{4.13}$$

$$Q_{rkj} \geq 0 \quad (\beta_{rkj}) \tag{4.14}$$

The KKT conditions of the optimization problem produce the following equations, 4.15, 4.16, 4.17 and 4.18.

$$\forall r,k,j : \alpha_{rkj} - \beta_{rkj} = U'_{kj}(Q_{rkj}) - c_r \tag{4.15}$$

$$\forall r,k,j : \sum_k \sum_j p_{kj}\alpha_{rkj} = f_r \tag{4.16}$$

$$\forall r,k,j : \alpha_{rkj} \geq 0 \;\; \& \;\; Q_{rkj} - K_r \leq 0 \;\; \& \;\; \alpha_{rkj}(K_r - Q_{rkj}) = 0 \tag{4.17}$$

$$\forall r,k,j : \beta_{rkj} \geq 0 \;\; \& \;\; Q_{rkj} \geq 0 \;\; \& \;\; \beta_{rkj}Q_{rkj} = 0 \tag{4.18}$$

The KKT conditions show that the optimal dispatch has the property that if the generation rate of generator type r is greater than zero and less than the total capacity of that generator (i.e. $Q_{rkj} > 0$ & $Q_{rkj} < K_r$), the production rate is determined by the point where the demand curve intersects the variable cost curve (i.e. $U'_{kj}(Q_{rkj}) = c_r$). When the rate of production for the generator type r is equal to its installed capacity (i.e. $Q_{rkj} = K_r$), the price can be above the marginal cost of generator type r. The KKT condition can be seen in the equation 4.19, according to which the level of investment in new installed capacity of a given type is optimal when the difference between the average price and the variable costs of that generator is equal to the per unit fixed cost of new additional capacity.

$$\sum_k \sum_j p_{kj}\alpha_{rkj} = \sum_{k,j:P_{kj}>c_r} p_{kj}(P_{kj} - c_r) = E((P - c_r)|(P > c_r))Prob(P \geq c_r) = f_r$$
$$\Longrightarrow E(P|P > c_r) = c_r + \frac{f_r}{Prob(P > c_r)} \tag{4.19}$$

The profit for each generator is given in the equation 4.20. In the optimal market condition, all generators have a zero profit.

$$E(\pi_r) = \left(E(P|P > c_r) - c_r - \frac{f_r}{Prob(P > c_r)} \right) K_r = 0 \tag{4.20}$$

4.4.8 Risk Assessment

In this section, risk-neutral and risk-averse investment decision-making are discussed and the optimal investment in new generation capacity for both risk-neutral and risk-averse investors is calculated.

4.4.8.1 Risk-neutral Investment

In a competitive energy-only market with a free-entry and free-exit for all generation capacity, the expected profitability of new investment is zero (i.e. $E(\pi_r) = 0$). The reason is that if the expected profitability of new investment in positive, the investors will invest more additional generation capacity due to its profitability. Otherwise if the expected profitability of new investment in negative, the investors will withdraw a portion of installed generation capacity. Therefore, if the expected profitability of new additional investment at each year during its lifetime is zero, the total amount of installed generation capacity in a competitive electricity market would be optimal. In presence of optimal installed generation capacity, the expected price must satisfy the equilibrium given in Equation 4.19. As mentioned in 4.3, it is assumed that new generation capacity will be in CCGT power plants and this generation capacity is represented by r^*. Following the previous section, the expected profit of new installed capacity in the form of generation technology r^* in the year i is defined as $E(\pi_{r^*,i})$. The sum of the expected annual profit over the lifetime (L) of the new installed capacity discounted by the discount rate of a results in the expected Net Present Value (NPV) of the new investment which is defined in the equation 4.21. At the equilibrium point, an energy-only market provides the optimal level of investment in new capacity if the expected NPV is zero.

$$E(NPV) = \sum_{i=1}^{L} \frac{E(\pi_{r^*,i})}{(1+a)^i} \tag{4.21}$$

4.4.8.2 Risk-averse Investment

High volatility of electricity prices and uncertainty when it comes to the future market design and regulation policies lead to a higher risk associated with the investment in generation capacity. Moreover, fluctuating global economic conditions, existing barriers for trade in the market, market interventions such as price caps and support policy schemes for renewables are some of the reasons why future investment in conventional generators is viewed as highly risky. Hence, investors require responsive strategies taking into consideration the risk associated with the investment in order to ensure the profitability of their investment.

Risk-aversion means that investors make investment decisions based not only on the expected profit from investment but also by considering the consequences in case the investment returns are lower than the initial expectation. In literature, Value at Risk (VaR) and Conditional Value at Risk (CVaR) are mainly used to measure the risk by assessing the probability of losses [RU00]. CVaR, which is an extension of VaR, is often used to assess the probability of a portfolio incurring large losses by evaluating the likelihood (at a specific confidence level) that a specific loss exceeds the value at risk. The VaR_α of a portfolio is the lowest amount such that with probability of α the loss will not exceed the given amount. $CVaR_\alpha$ is the conditional expectation of losses exceeding that amount. In other words, the $CVaR_\alpha$ of profit π is the expected loss if one's interest is restricted to the lowest $100\alpha\%$ of returns. If the profit π has a cumulative distribution function $F(\pi)$ and a probability density function $f(\pi)$, then $CVaR_\alpha(\pi)$ is defined as is shown in the equation 4.22.

$$CVaR_\alpha(\pi) = -\frac{1}{\alpha}\int_{-\infty}^{F^{-1}(\alpha)} \pi f(\pi) d\pi \tag{4.22}$$

In this study, CVaR is used to measure the risk of investing in new generation capacity. CVaR measures the downside risk by considering the average profit from the lower quantile of profit distribution. The values for VaR and CVaR in a typical normal NPV distribution are depicted in Figure 4.13. The objective function is modified to account for investment risk by establishing a trade-off between expected profit and risk. The risk-adjusted NPV is given in the equation 4.23 and reflects the desire of risk-averse investors to maximize their expected profit on the one hand and to minimize the downside risk of their profit on the other hand.

$$E(NPV^{RiskAdj}) = \lambda E(NPV) + (1-\lambda)CVaR_\alpha \tag{4.23}$$

λ represents the risk-aversion factor and lies between 0 and 1. When $\lambda = 1$, the decision criterion becomes the expected profit and the investors' decision will be risk-neutral. When $0 < \lambda < 1$, the objective function describes risk averse behavior while the lower the λ value the higher the level of risk-aversion. Alternatively, when $\lambda = 0$, decision makers are characterized by a high degree of risk aversion in their decisions and focus on the downside risk associated with the profit rather than on the expected profit.

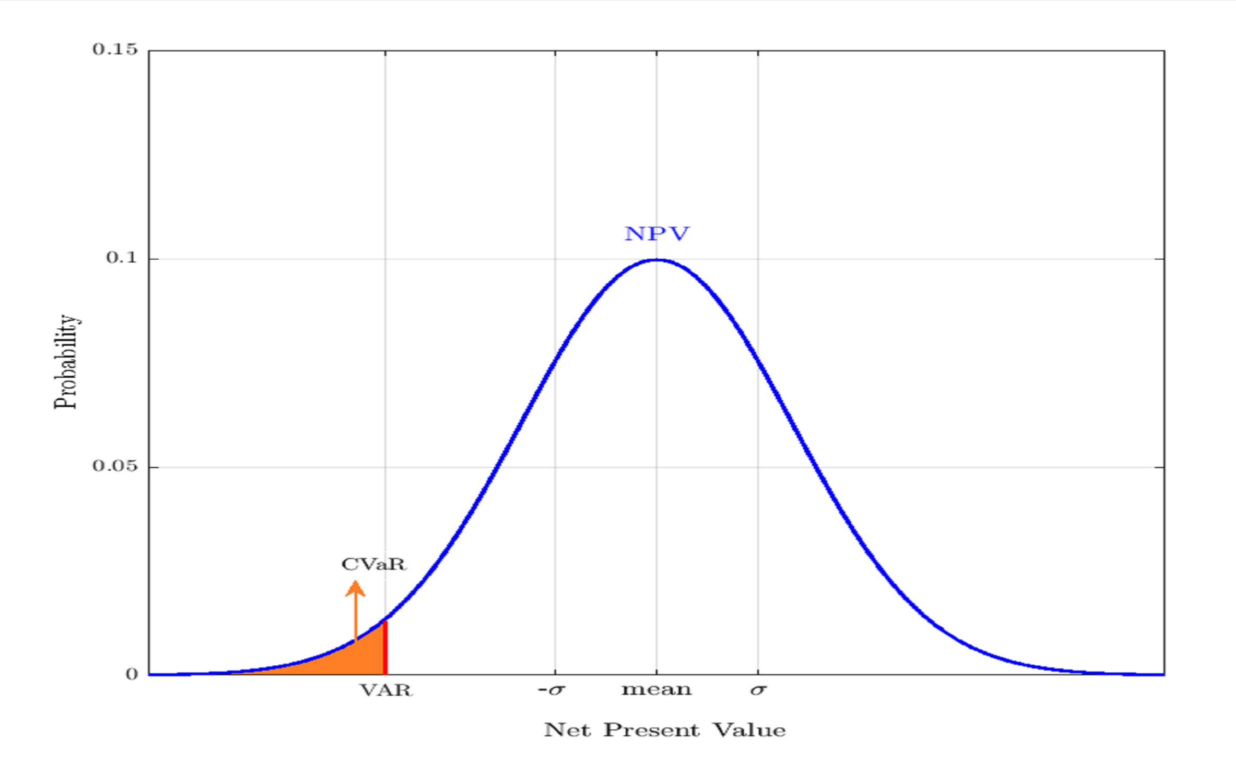

Figure 4.13: VaR and CVaR in the NPV distribution function

4.5 Model Verification

In this section, the proposed model is verified to ensure that the model implements the assumption correctly and it behaves as it was intended. In the following, several scenarios are defined to test the model output and verify the model.

4.5.1 Price Verification

The actual day-ahead prices and the prices derived from the model for 2012 are depicted in Figure 4.14. It shows that price curve derived from the model follows the trend of the actual prices. However, the actual prices and model prices do not completely fit to each other due to the main assumptions of the model which are discussed in 4.4.1 and mentioned in the following. First, the model considers a single bidding price for power plants with a similar generation technology, e.g.

45 €/MWh for all coal power plants. However, the marginal cost for each generation technology typically varies within a range of prices, e.g. the range of 39 €/MWh to 52 €/MWh for the short-term marginal cost of coal power plants in the German electricity market. This is the reason that price curve derived from the model is a discrete curve. Second, proposed model does not consider the cross-border electricity trade with neighboring countries which could result a difference between model price and actual hourly prices. Third, the day-ahead forecast of load values is used in the day-ahead auction to determine the hourly prices. The proposed model uses the actual load values in the day-ahead auction because the day-ahead load forecast data is not available in general. However, the day-ahead load forecast error is typically very low and load values can be very well predicted. Fourth, the proposed model has the lack of ability to model the duration and amount of negative prices. Negative prices mainly occur when a large inflexible electricity generation appears simultaneously with low demand. In case if the electricity generation from renewables becomes higher than hourly load, the proposed model set the hourly electricity price equal to zero.

4.5.2 Zero Demand Growth Scenario

In the proposed model, generation resource adequacy in the German electricity market is modeled for a 30-year period from 2012 to 2042. The initial effective capacity in 2012 is assumed to be 80,000 MW while the peak load in that year is 74,475 MWh which results an initial overcapacity of approximately 7% of peak load. Demand response penetration capacity is assumed to be equal to 15% of peak load at each year. In this section the demand growth rate is assumed to be zero. It means that the peak demand will remain constant across all 30-years simulation period. Figure 4.15 shows the annual installed capacity, profitability of new installed capacity, annual demand response utilization duration, and annual load shedding duration during the simulation period in presence of defined scenario. Due to the initial overcapacity, the expected profitability of new additional capacity is negative in 2012. As the peak load remains fixed during next years, the profitability of new additional capacity remains negative and as a consequence the volume of new installed capacity is zero. Besides, as there is no load shedding or no need for demand response utilization in the first year, it will remain the same for the next years.

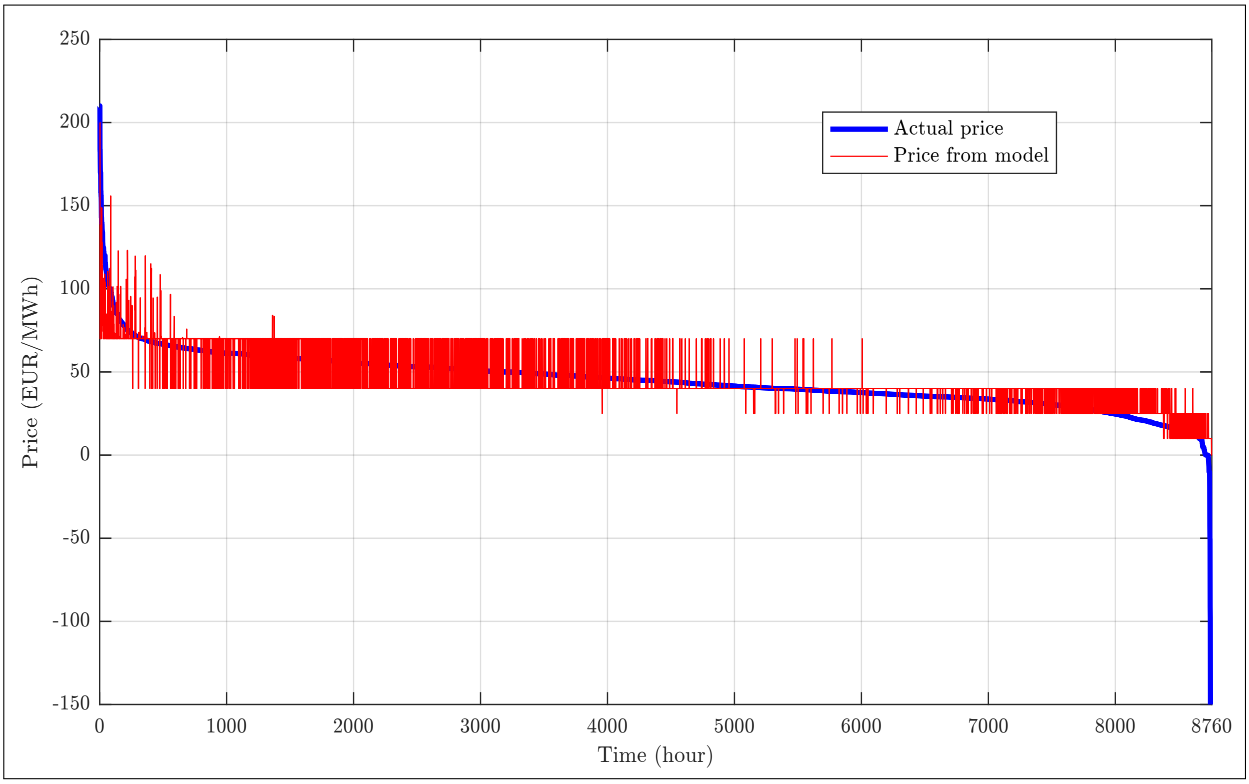

Figure 4.14: Comparison of actual hourly prices versus the prices resulted from model

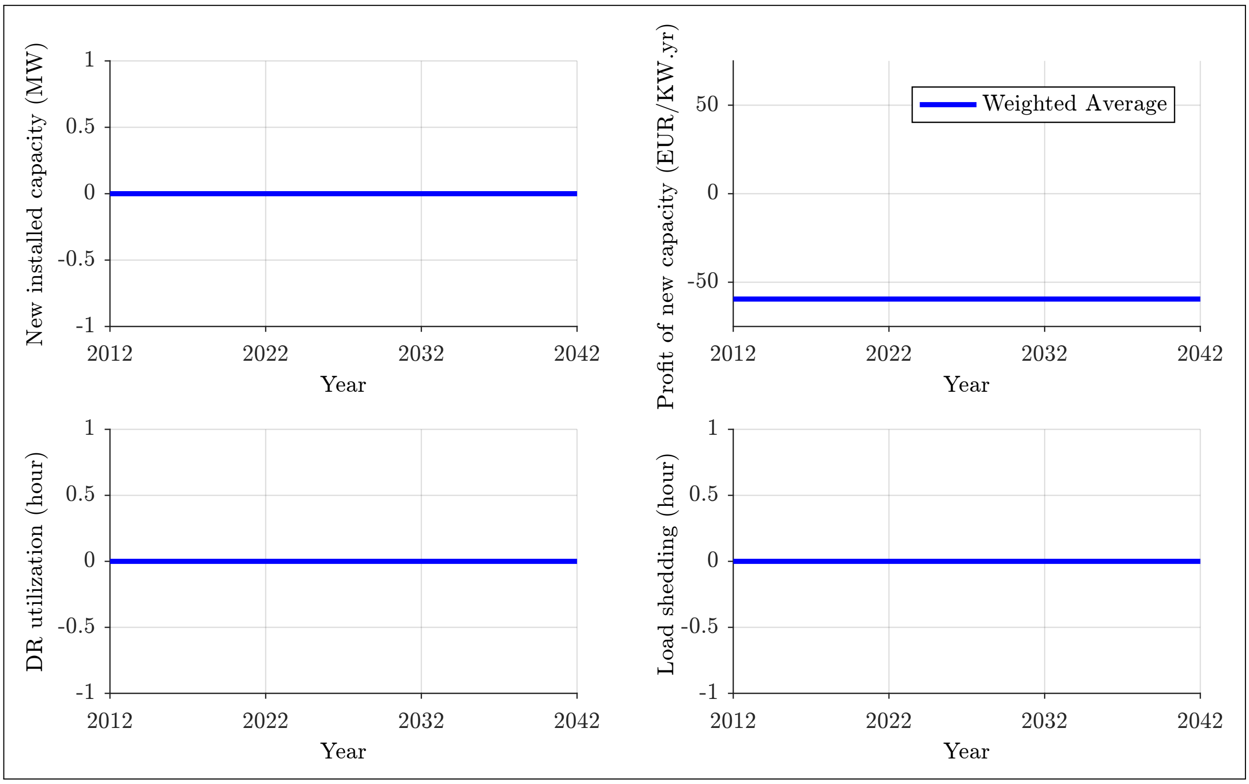

Figure 4.15: Resource adequacy criteria in zero demand growth rate scenario

4.5.3 Deterministic Scenario

In this section the resource adequacy condition is presented by considering the assumption that there is no randomness in the model. The generation and demand time series for each year are deterministic and the uncertainties in generation and load are not included. The demand growth rate is assumed to be 1% for each year and the initial overcapacity is approximately 7% of peak load. Demand response capacity is assumed to be equal to 15% of peak load at each year. Figure 4.16 shows the variation of resource adequacy criteria based on the defined scenario. Due to the initial overcapacity, the expected profitability of new capacity is negative which results in no investment in new capacity from 2012 to 2025. While the new installed capacity is zero, the DR utilization period increases every year due to increase in the demand. When the expected profitability of new capacity becomes zero, the new generation capacity starts to be added into the market. As a consequence, the DR utilization period remains fixed. As there is enough installed capacity and DR capacity in each year, the load shedding never occurs.

4.5.4 Higher fixed cost of CCGT Scenario

In this section, the impact of higher fixed cost of new generation capacity on the load shedding hours is studied. To this aim, it is assumed that demand response does not exist in the market and the generation and load values for each year are deterministic values. As mentioned in 4.3, the type of new generation capacity is CCGT power plant. Figure 4.17 shows the number of load shedding hours at two different CCGT fixed costs: average CCGT fixed cost of 59,500 €/MW.yr and its double 119,000 €/MW.yr. As there is no demand response capacity, the profit for new generation capacity would be equal to the number of load shedding hours multiplied by the value of lost load (VOLL). As it is expected, higher fixed cost of CCGT plants leads to a greater number of load shedding hours. The reason is that the expected revenue of new installed capacity in high fixed cost scenario should be higher in order to recover the higher fixed cost of new generation capacity. However, higher fixed cost of CCGT plants results in less installed capacity in the market.

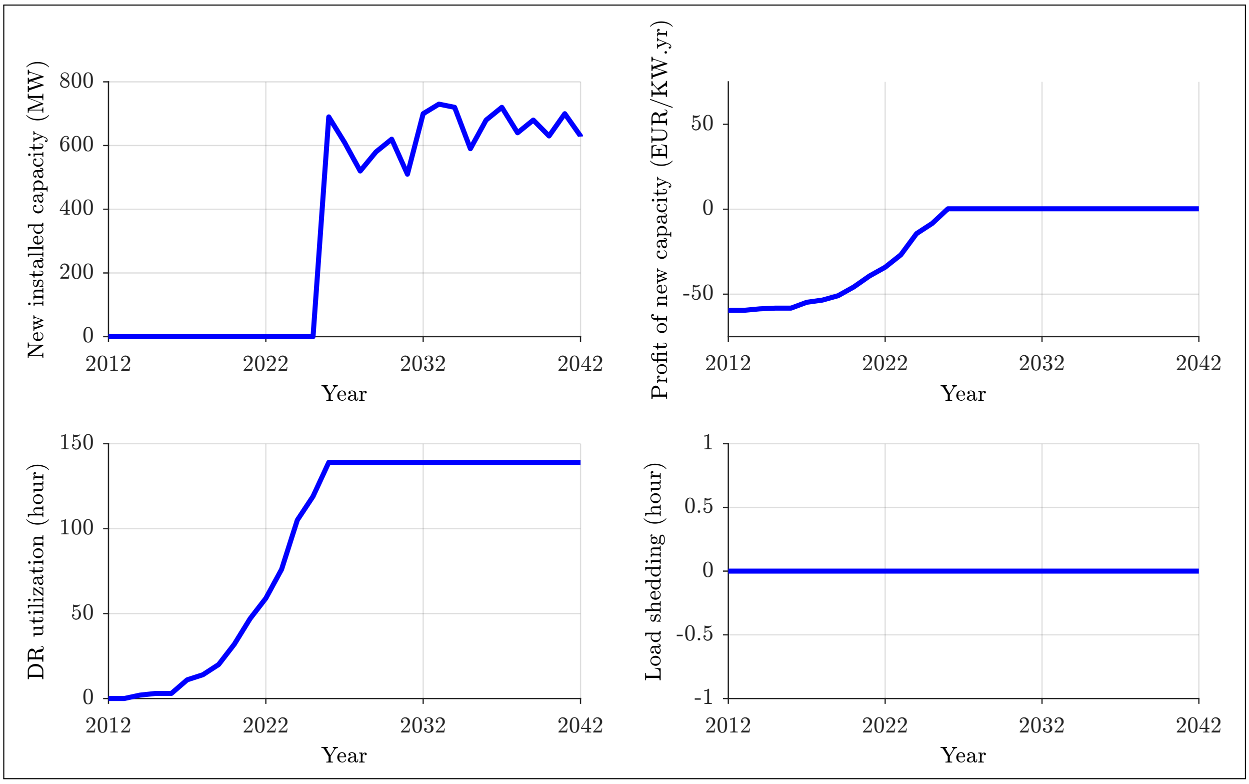

Figure 4.16: Resource adequacy criteria in deterministic scenario

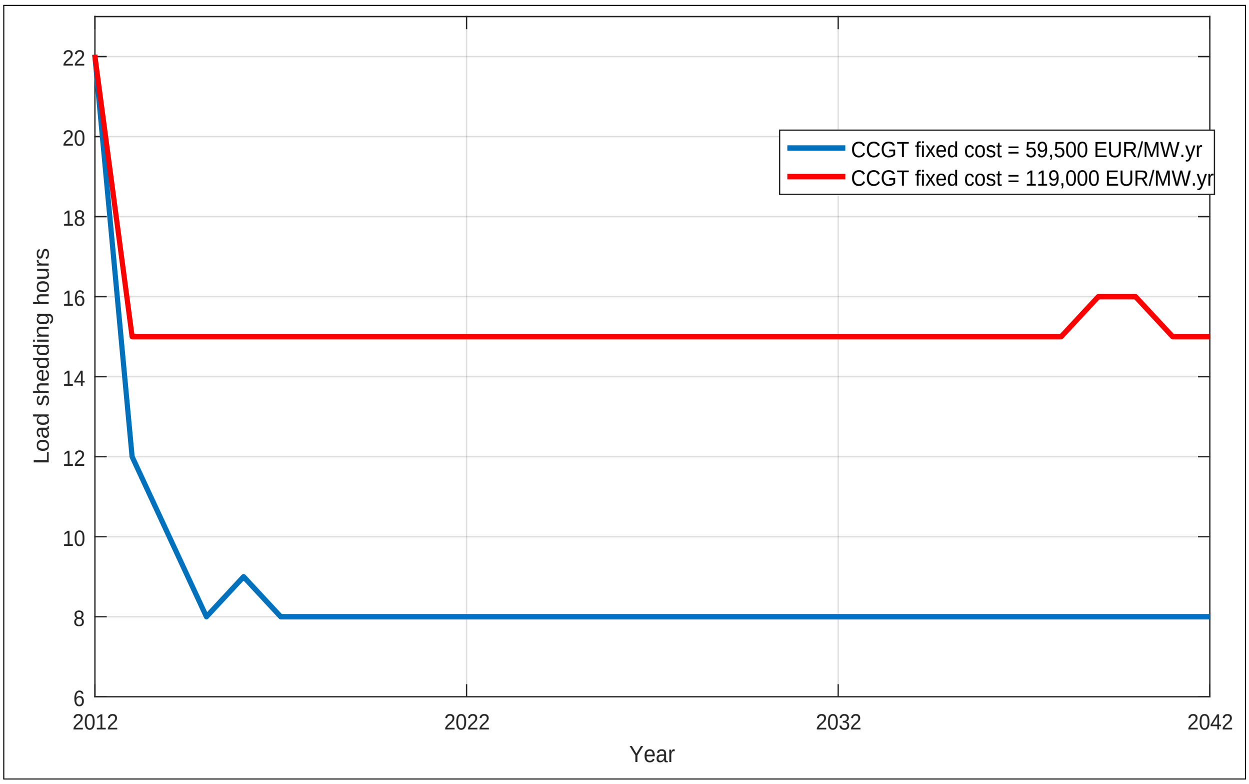

Figure 4.17: Comparison of load shedding duration at different CCGT fixed costs

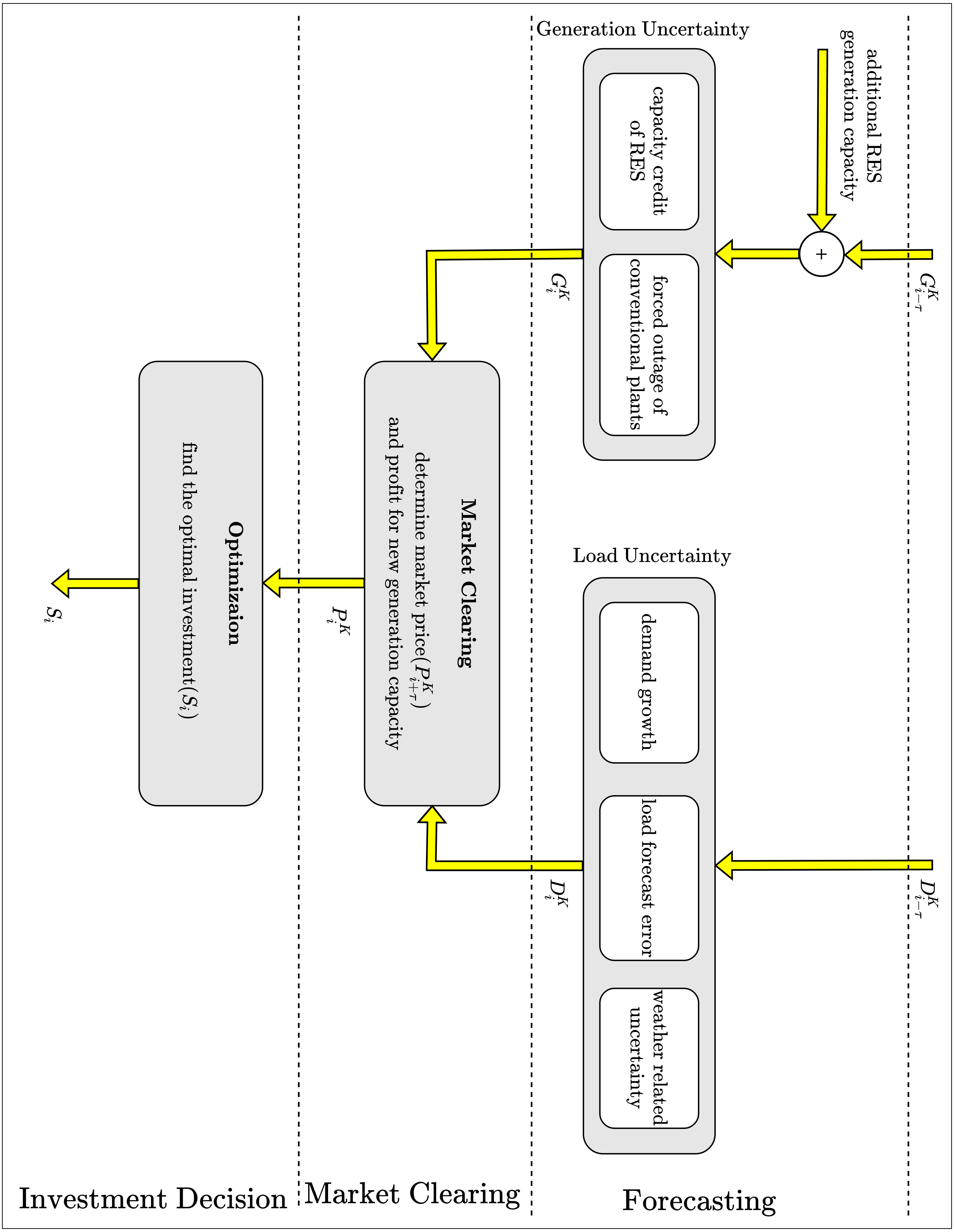

Figure 4.3: Simulation flowchart for one year

5 Long-term Resource adequacy Condition

In this chapter resource adequacy criteria related to risk-neutral and risk-averse investment in new generation capacity are analyzed and the impact of investment risk on long-term resource adequacy in the German electricity market is discussed. Then, the required economic and emergency demand response (DR) needed to guarantee long-term resource adequacy is estimated. Furthermore, the effect of a price cap on resource adequacy is evaluated. As a case study, the generation resource adequacy in the German electricity market from 2012 to 2042 is studied. The main questions which are addressed in this chapter include:

- What is the impact of investment risk and price cap on the long-term resource adequacy? How sensitive are resource adequacy criteria to these factors?
- What is the optimal volume of emergency and economic demand response capacity to ensure generation resource adequacy in the German electricity market
- How much is the resource adequacy value of demand response in the German electricity market?

5.1 Risk-neutral Generation Investment

Risk-neutral investors decide to invest in new generation capacity if the expected profitability of new investment is zero. The economic DR capacity is modeled as follows. There is no demand response from 2012 to 2021 (first 10 years of the simulation period). From 2022 to 2031 the available economic DR capacity is equal to 2% of peak demand in each year and the available economic DR from 2032 to 2042 is equal to 4% of peak demand in each year. Besides, the initial overcapacity in the German electricity market is assumed to be 5% of peak load in 2012. This overcapacity is considered to be effective installed capacity, meaning that it is fully available during the year.

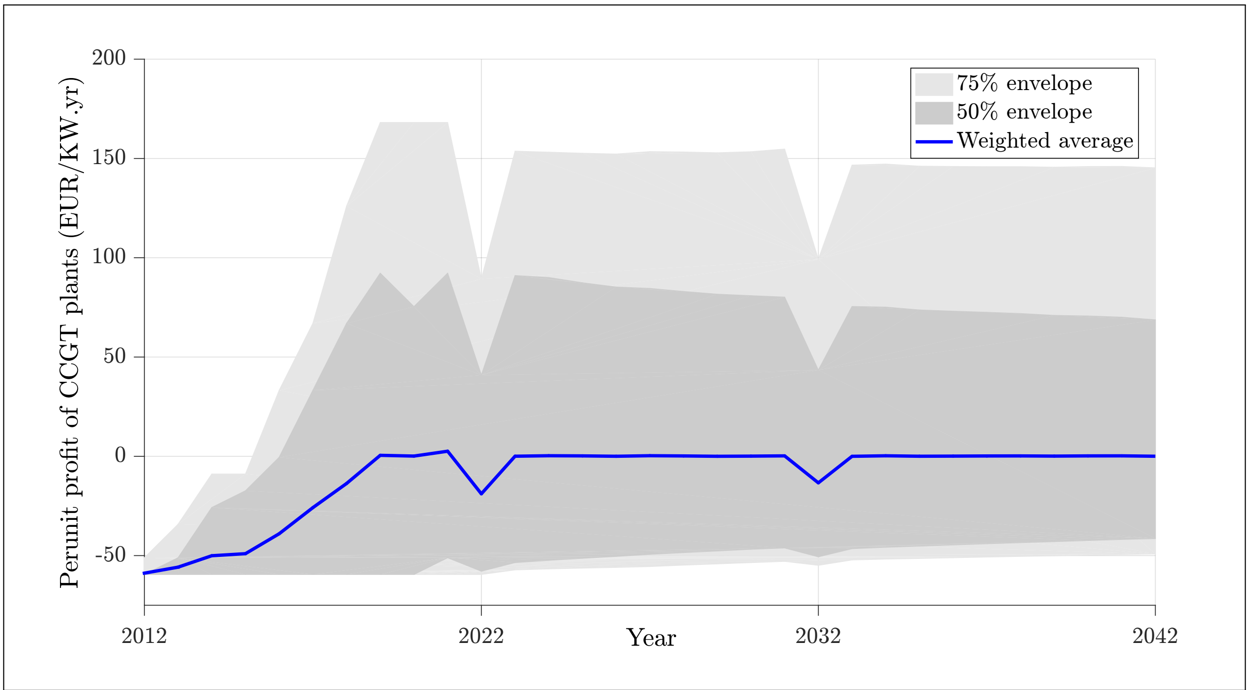

Figure 5.1: Profit of new generation capacity in case of risk-neutral investment (€/KW.year)

The distribution of profitability of new installed combined-cycle gas turbine (CCGT) power plants under different uncertainty scenarios is shown in Figure 5.1. Besides, the weighted average volume of annual new installed CCGT capacity is depicted in Figure 5.2. The initial overcapacity in the market results in a negative profit (or a loss) for gas power plants and a delayed investment in new capacity. This happens due to fact that overcapacity reduces the probability of high prices as a result of which inframarginal rents are not high enough to incentivize new investment in the market. From the beginning of 2018, the average profit from new installed capacity becomes non-negative, which prompts investment into new capacity. The profitability distribution for new capacity is more stretched toward the positive values, which indicates the probability for investors to earn very high profits from their new investment although such a probability is relatively low (see Figure 5.1). Results show that during the first year that DR becomes available or the year

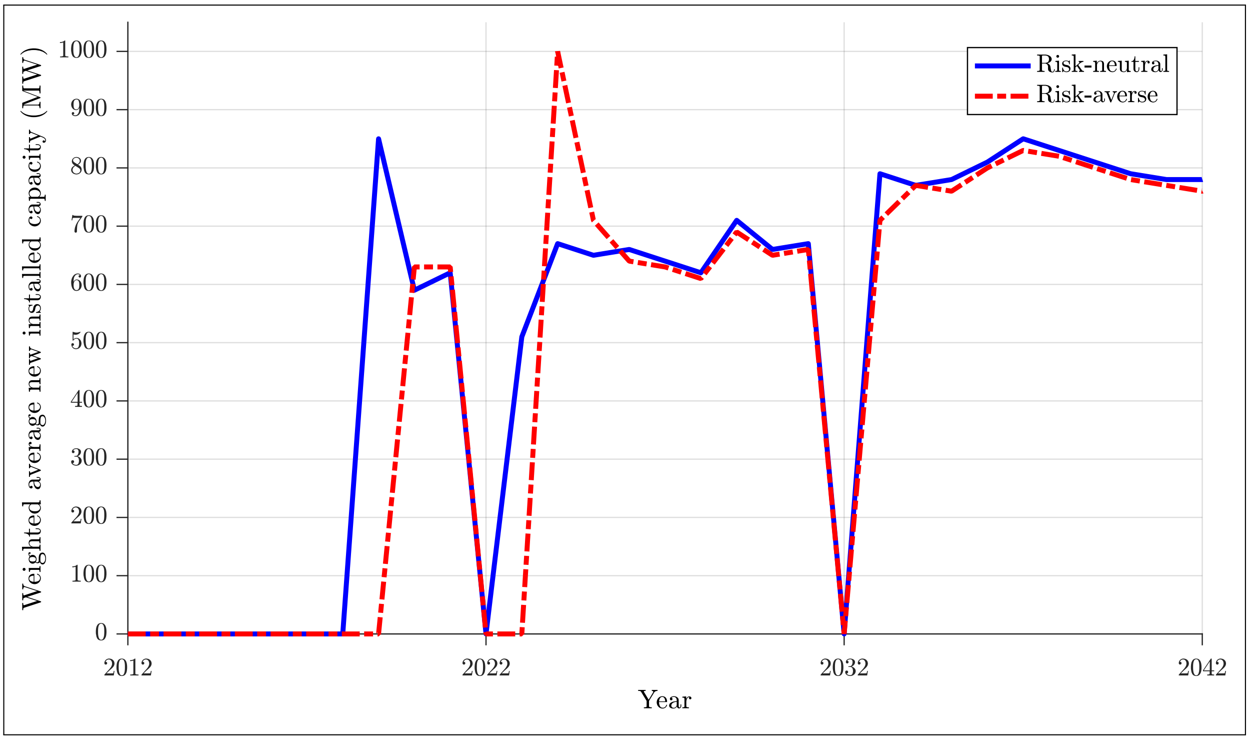

Figure 5.2: Weighted average new installed capacity in risk-neutral and risk-averse investment (MW)

that its volume increases in the market, the expected profitability of new investment becomes negative and new installed capacity in that year becomes zero. That is, since the newly introduced DR acts just like new generation capacity there is no longer an incentive to invest in additional capacity that year.

Annual load shedding and DR utilization periods are shown in Figure 5.3 and Figure 5.4. Initial overcapacity in the market results in a shorter load shedding period during the first years. As overcapacity in the market goes down, the probability of load shedding events increases and the duration of the average load shedding period rises up to 7 hours in 2021. The annual load shedding time reaches 27 hours in 2021 within a 75% confidence interval. From 2022 to 2031 a DR volume equal to 2% of annual peak load is introduced into the market. Consequently, the average annual load shedding period decreases to 4 hours per year and the average period of DR utilization increases up to 9 hours per year. The DR capacity increases by 4% of peak demand in each year from 2032 to 2042. As a result, the average annual load shedding period drops to 2 hours and the average annual DR utilization period increases to 13 hours per year. This is caused by the fact that the deployment of DR and load shedding lead to higher market

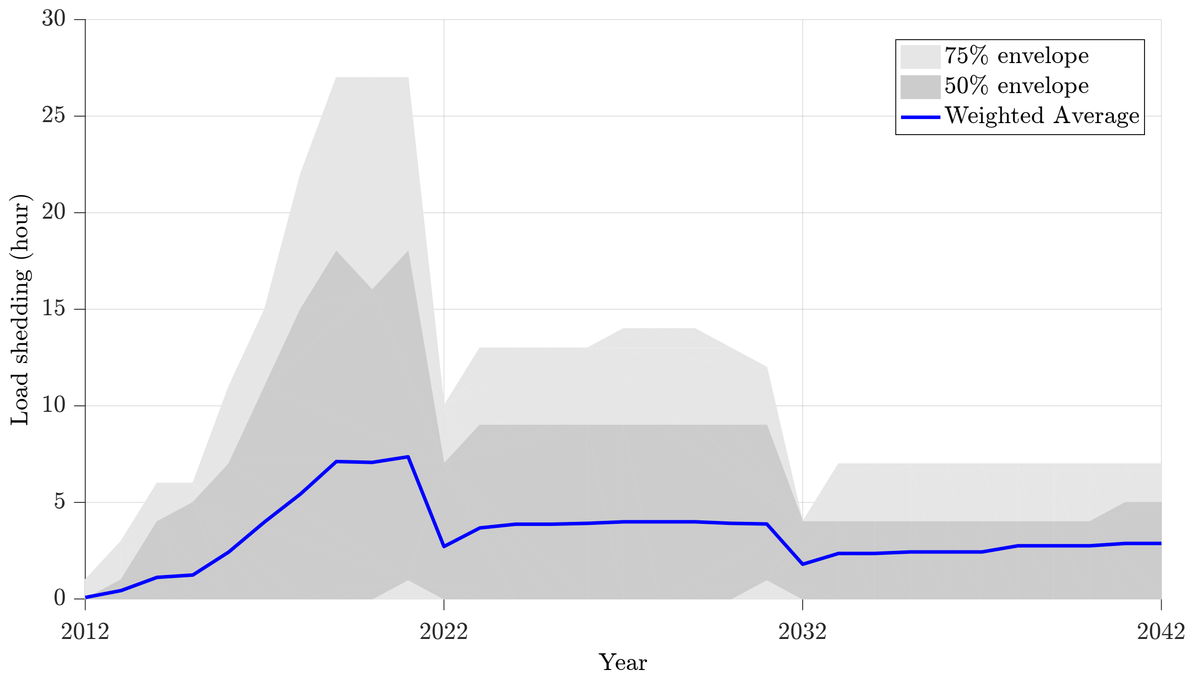

Figure 5.3: Annual load shedding period in case of risk-neutral investment (hours/year)

prices and, subsequently higher inframarginal rents for new installed capacity which secures their profitability and cost recovery. The annual DR call hours between 2032 and 2042 go up to reach 45 hours per year in a 75% confidence interval. When there is an optimal investment in new capacity in the market, higher DR capacity results in shorter load shedding periods.

The weighted average price duration curves for three different years with different level of available DR capacity are depicted in Figure 5.5. The 100 highest average prices in the price duration curve is depicted in upper figure and the rest of the curve is depicted in lower figure. The share of variable RES in generation profile is increasing from 28% in 2020 to 35% in 2027 and 43% in 2035. By increasing the generation capacity of variable RES, the right-side of price duration curve is shifted to the left and average number of hours that variable RES is the marginal producer is increasing. Besides, new additional investment results in the increasing CCGT generation capacity from 2020 to 2035 (see Figure 5.2). Therefore, the average duration that CCGT is the marginal producer is increasing from 645 hours in 2020 to 743 hours in 2027 and 1027 hours in 2035.

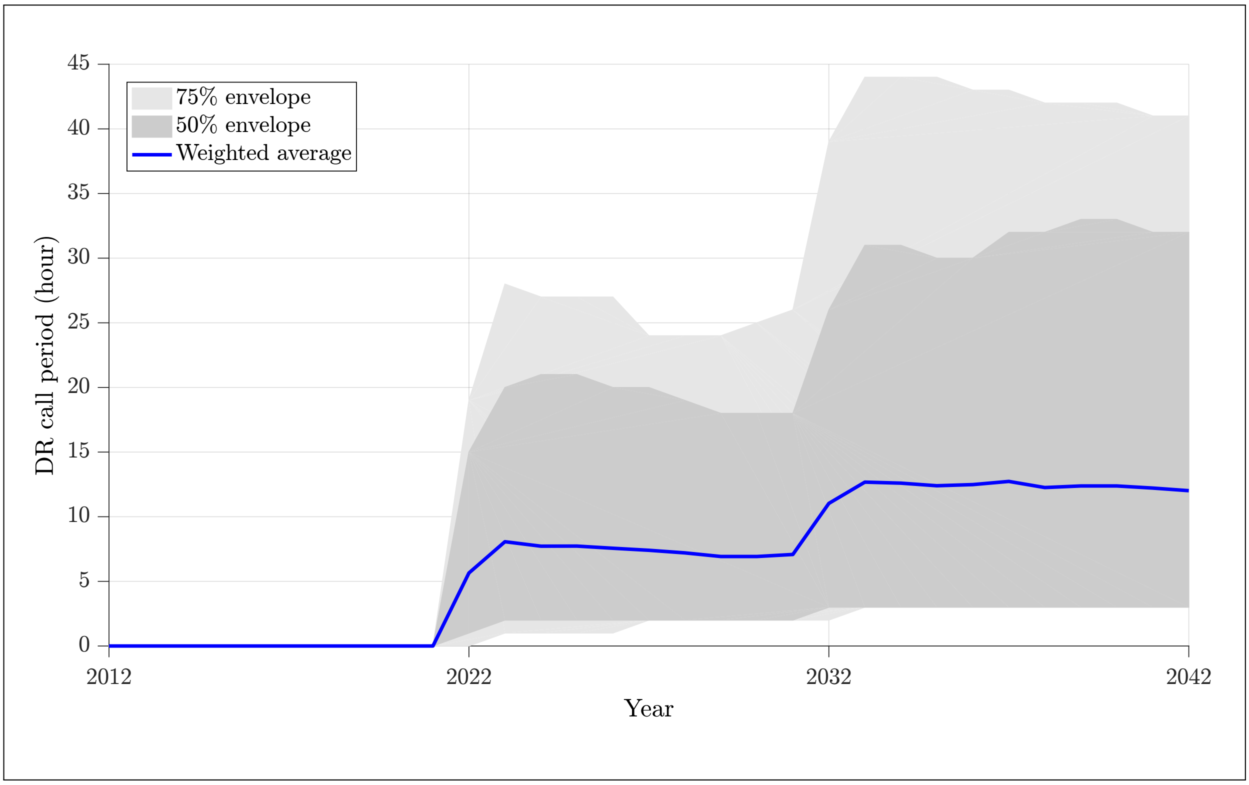

Figure 5.4: Annual demand response utilization in case of risk-neutral investment (hours/year)

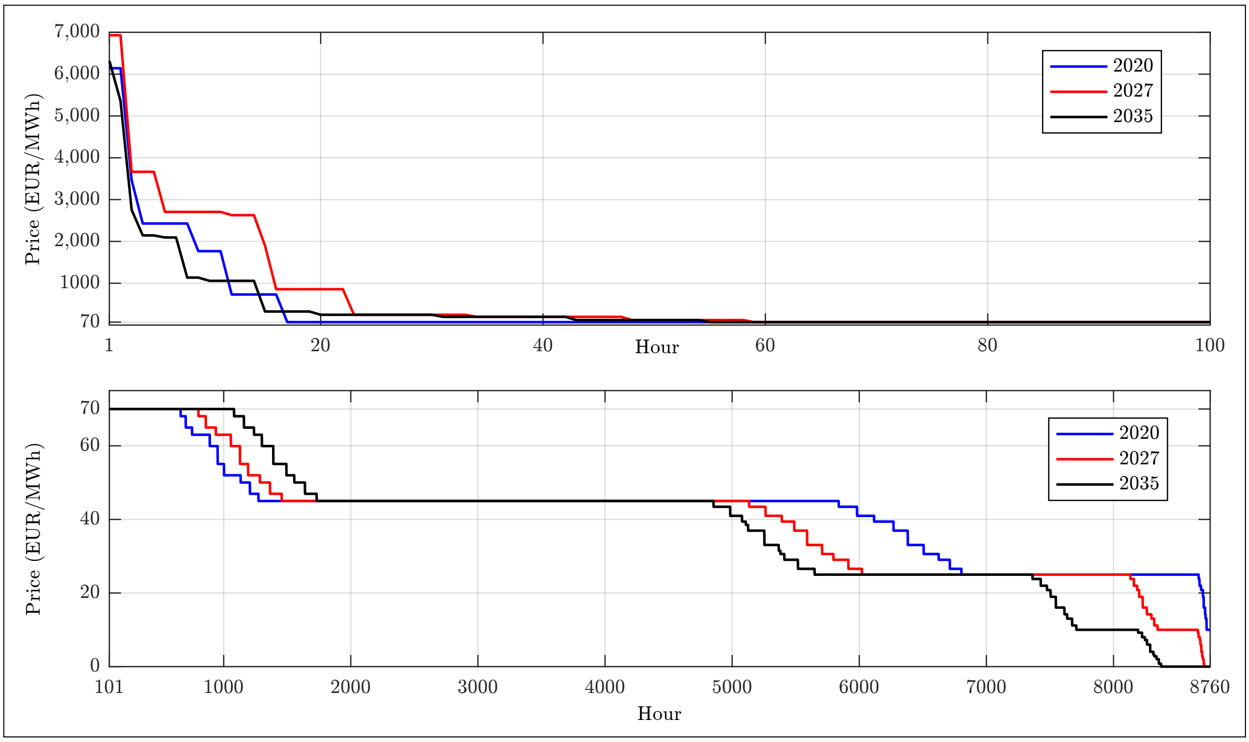

Figure 5.5: Weighted average price duration curve in different years

5.2 Risk-averse Generation Investment

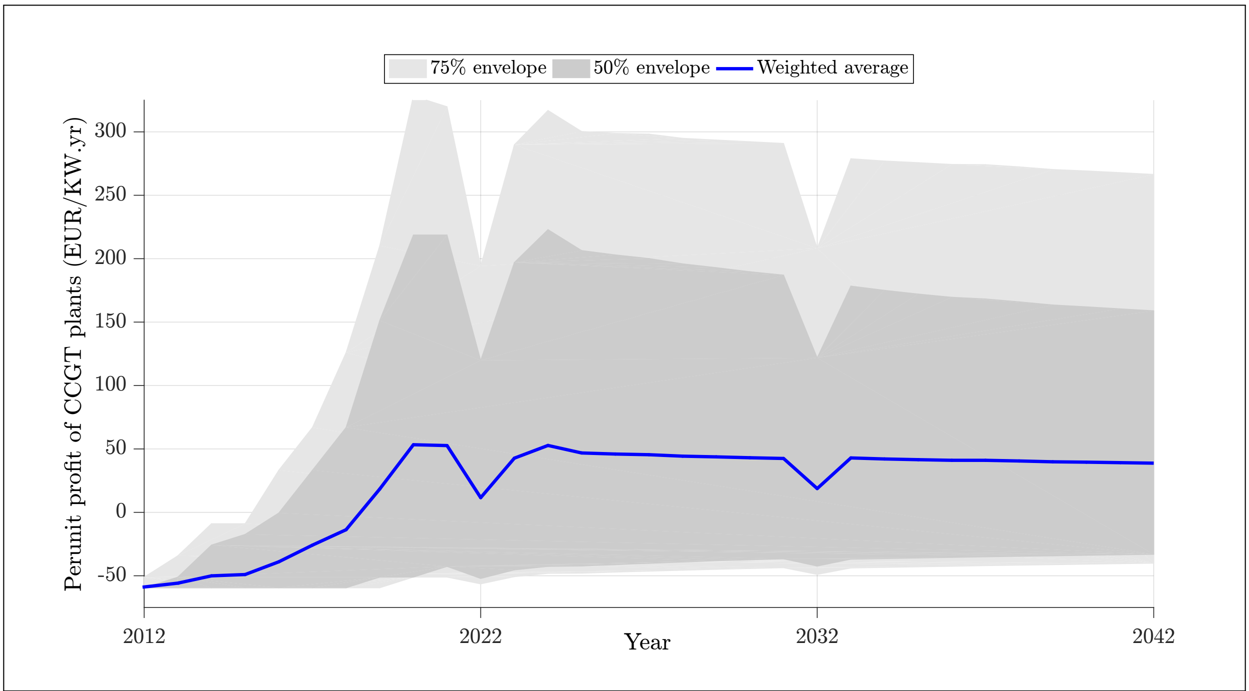

Figure 5.6: Profit of new generation capacity in case of risk-averse investment ($\alpha = 0.1, \lambda = 0.5$)

In this section the result for risk-averse investment in new generation capacity is compared to risk-neutral investment decisions. Risk-averse investors make investment decisions based on the expected risk-adjusted net present value (NPV) which is given in equation 4.23. The economic DR capacity is modeled as follows. No DR is deployed from 2012 to 2021 and available DR capacity is equal to 2% of annual peak demand from 2022 to 2031. DR capacity from 2032 to 2042 equals 4% of peak demand in each year. The values for α and λ are assumed to be 0.1 and 0.5, respectively. The profitability distribution of new installed capacity is shown in Figure 5.6. The weighted average per-unit profit of new capacity in risk-averse investment environment is equal to 60% percentile value in the profit distribution. Therefore, Risk-averse investors' marginal expected NPV is higher than the marginal expected NPV of risk-neutral investors. In the former case the expected NPV is equal to 55 €/KW.year while the expected NPV of the latter is zero. Risk-averse investors thus have a higher profit margin and are less vulnerable to fluctuations and uncertainties in the market. Initial overcapacity in risk-averse scenarios results in a greater delay in new investment compared to the risk-neutral scenario (see Figure 5.2).

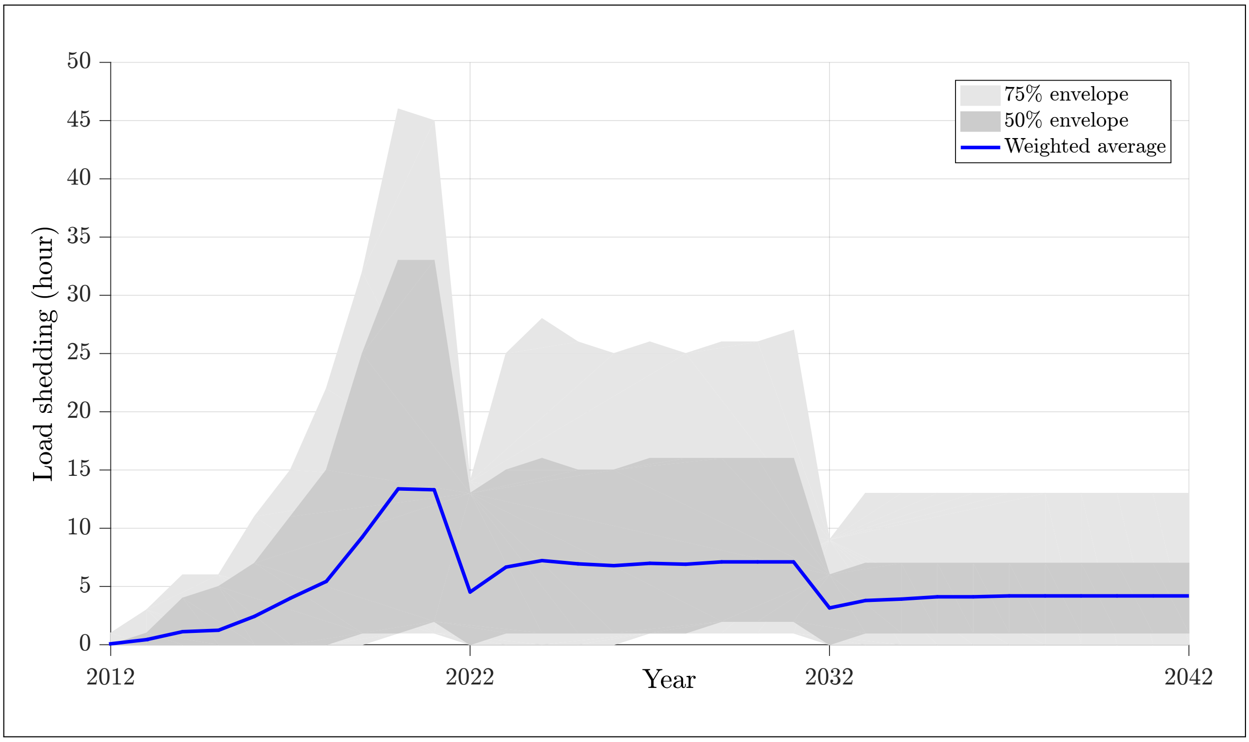

Figure 5.7: Annual load shedding in the risk-averse investment scenario ($\alpha = 0.1, \lambda = 0.5$)

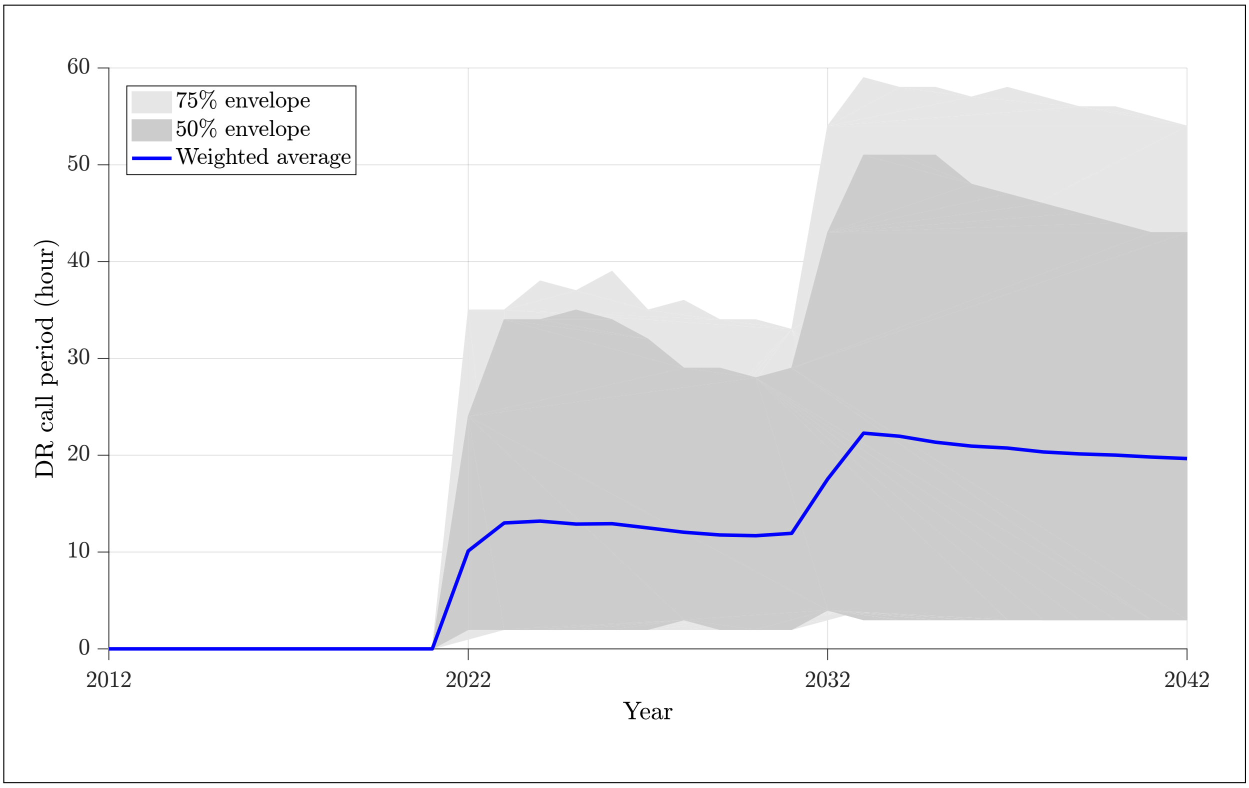

Figure 5.8: Annual demand response utilization in the risk-averse investment scenario ($\alpha = 0.1, \lambda = 0.5$)

The annual load shedding and DR utilization periods are shown in Figure 5.7 and Figure 5.8, respectively. The impact of DR and initial overcapacity on both the duration of DR utilization and load shedding periods in case of risk-averse investment is similar to that in the risk-neutral one. The main difference is that both average load shedding and average DR utilization periods are higher in the risk-averse environment. Besides, risk-aversion leads to a wider range of load shedding period and DR call hours. The reason is that risk averse investors make more conservative investment decisions, which leads to less installed capacity compared to risk-neutral investors and the probability of shortage and DR utilization increases. For instance, the number of DR calling hours within a 75% confidence interval in 2040 and in the presence of risk-averse investment rises up to 56 hours, which corresponds to 44 hours in case of risk-neutral investment.

5.3 Sensitivity Analysis of Risk-aversion Parameters

A sensitivity analysis of investors' risk-aversion parameters and their impact on the resource adequacy criteria are shown in Figure 5.9. This figure shows how risk aversion leads to different volume of weighted average new installed capacity, weighted average profit of new capacity, and weighted average DR utilization and load shedding period. λ denotes the risk-aversion factor with values between 0 and 1 and a lower λ represents a higher risk-aversion in investment decision making. α is assumed to be fixed and equal to 0.1. Results show that a lower risk-aversion factor leads to a lower share of new installed capacity, higher DR utilization, more frequent scarcity situations and higher expected profits from new capacity. A lower λ means that investors are more conservative and expect higher profit margins from their investment due to their risk-aversion, which in turn results in less investment in generation capacity compared to a higher λ. Therefore, the reserve margin in the market decreases, which produces more scarcity events and more frequent utilization of DR.

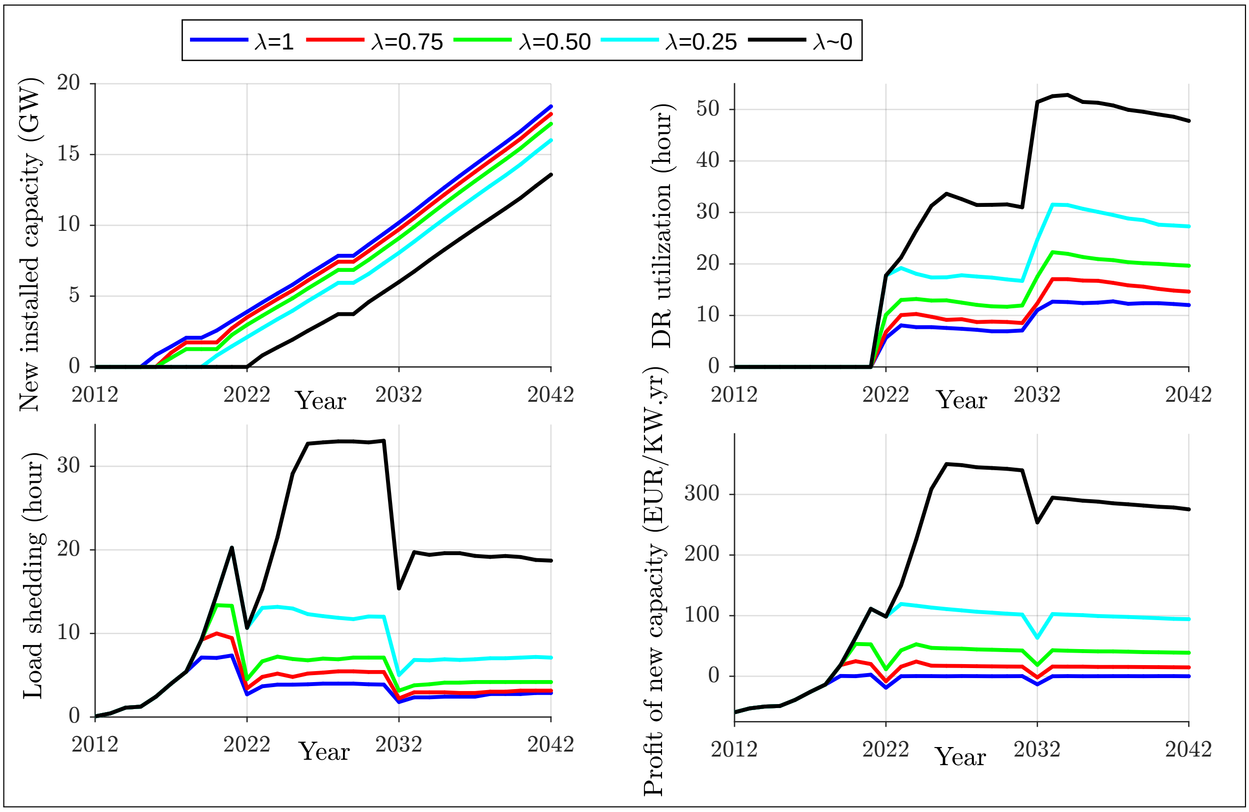

Figure 5.9: Sensitivity of resource adequacy criteria to risk-aversion parameter ($\alpha = 0.1$)

5.4 Demand Response

5.4.1 Economically Optimal DR Capacity

In this section two types of demand response (DR), emergency and economic DR, are modeled in the German electricity market. Based on the proposed model, the economically optimal emergency and economic DR capacity in scenarios with different shares of variable renewables and the sensitivity of both DR call hours and optimal DR capacity to different market parameters are evaluated. The model probabilistically calculates the DR capacity which is required to guarantee long-term generation resource adequacy during market operation. The amount of DR capacity required for safeguarding resource adequacy, which is called as the economically optimal DR capacity as well, depends on five main factors: installed generation capacity, available DR capacity or DR penetration level, DR dispatch price, price cap, and the share of variable renewables in the generation profile. A sensitivity analysis has been conducted in order to evaluate relative sensitivity of each parameter to the optimal DR while the other parameters remain fixed. The price cap is assumed to be equal to the Value of Lost Load (VOLL) and the available DR capacity is assumed to be 15% of peak load each year. The 15% DR penetration volume guarantees that load shedding will not occur during simulation period.

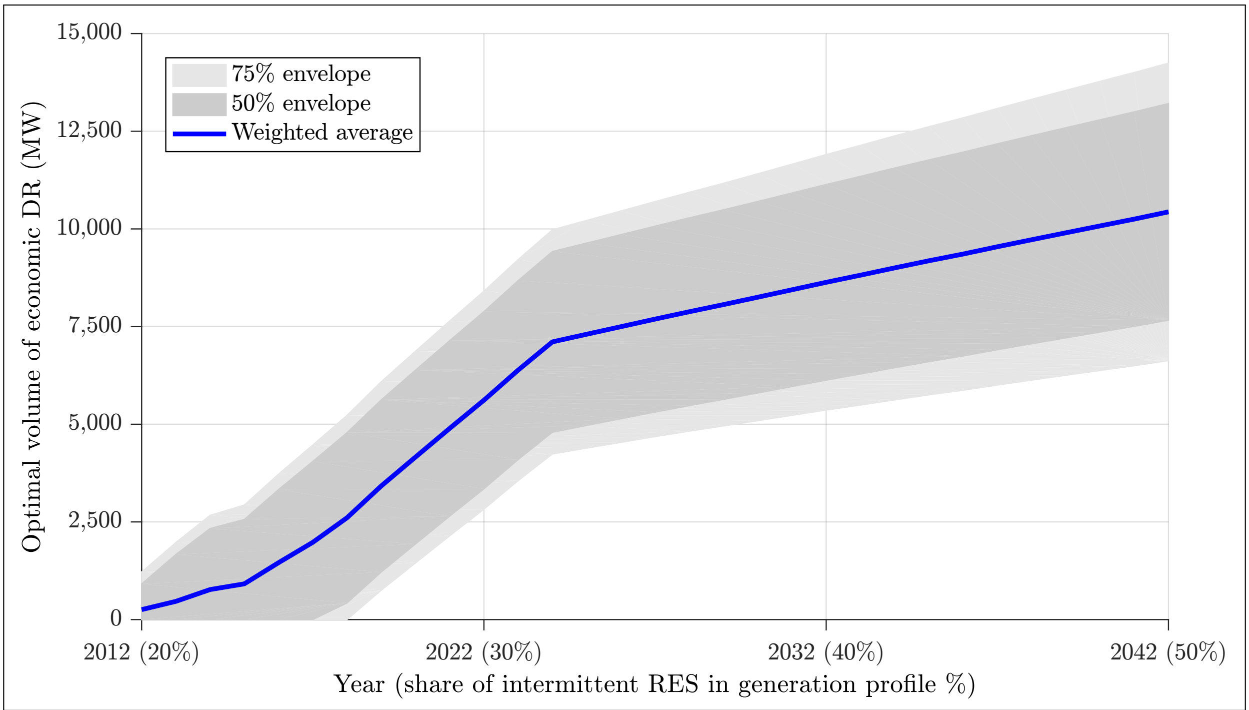

Figure 5.10: Optimal volume of economic demand response

Results show that in the presence of adequate DR volumes, an energy-only market could provide sufficient incentive for new investment in generation capacity eliminating the probability of scarcity events or load shedding. Figure 5.10 shows that higher share of variable RES results higher volume of economically optimal DR in order to avoid load shedding. While the share of RES in the generation profile rises to 50% in 2042 in the German electricity market, the weighted average economically optimal DR rises up to 10.5 GW and maximum of optimal DR with a 75% confidence interval amounts to 14.25 GW. In other words, 14.25 GW of economic DR is required in order to avoid load shedding with probability of 75%. As shown in Figure 5.11, the weighted average economically optimal emergency DR with the dispatch price of 2000 €/MWh at the same year equals 9.5 GW and maximum optimal emergency DR with a 75% confidence interval amounts to 13.37 GW. These results demonstrate that the amount of optimal economic DR is higher than that of the emergency DR with a dispatch price of 2000 €/MWh. Figure 5.12 shows that the economically optimal emergency DR capacity which is required to guarantee the generation adequacy depends on the DR dispatch price. By increasing the dispatch price of DR resources, the economically optimal DR volume decreases and vice versa. For instance, if emergency DR is offered at the price of 500 €/MWh, the market needs 15 GW of this DR type on average in order to avoid load shedding in 2042, while the average required DR with a dispatch price 1000 €/MWh and 2000 €/MWh is 11.8 GW and 9.5 GW, respectively.

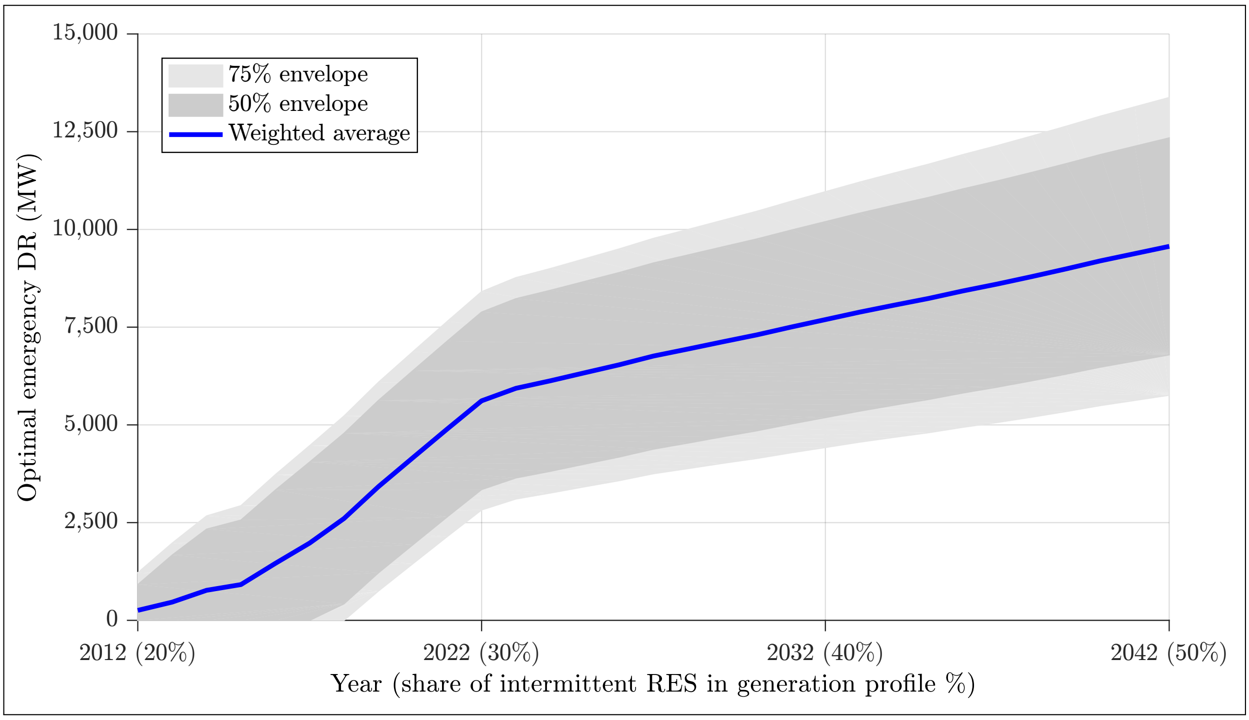

Figure 5.11: Optimal volume of emergency demand response with the dispatch price of 2000 €/MWh

Figure 5.13 demonstrates that the average number of DR call hours rises when the share of variable RES in the generation profile goes up. However, the average DR call period does not increase after some years since when new generation capacity begins to be added into the market, the average peak load hours and DR calling periods remain almost constant. In contrast, the required DR capacity is still increasing. Furthermore, lower DR dispatch prices result in higher average DR call hours (see Figure 5.13). The average DR call period in the presence of emergency DR with a dispatch price of 500 €/MWh reaches 140 hours per year.

The potential and barriers for DR utilization in Germany has been studied in [PB11], [Gil16], [Coa14], [Ste16]. Theoretical DR potential in household, industrial and tertiary sector for 40 European countries is estimated by considering technical characteristics of provided DR with

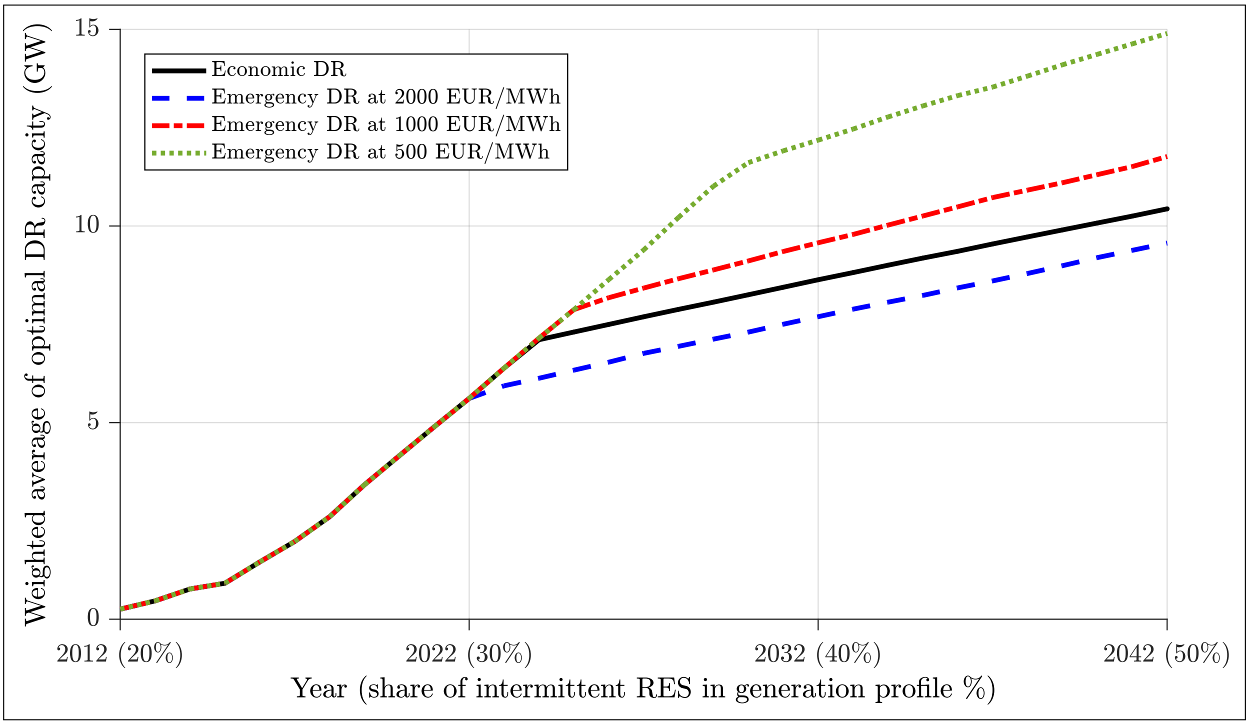

Figure 5.12: Optimal emergency and economic DR at different DR dispatch prices

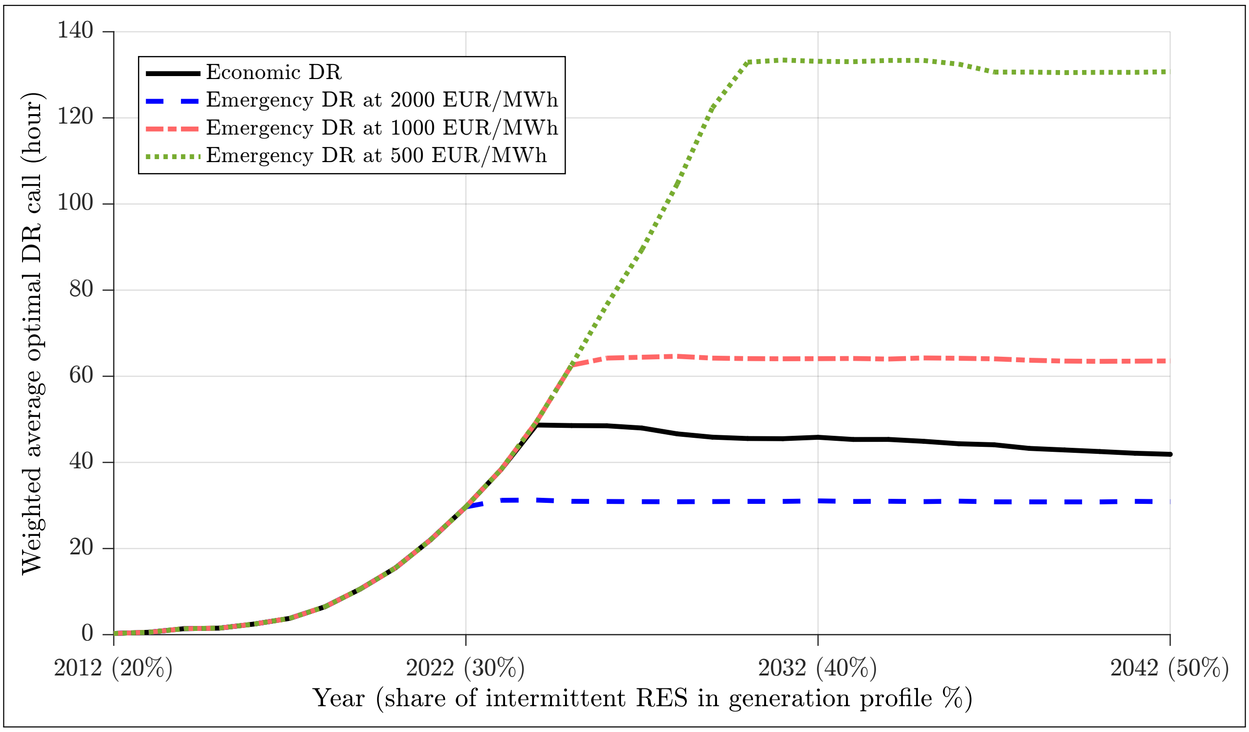

Figure 5.13: Demand response call duration at different DR dispatch prices

statistical load data in [Gil14]. The authors estimate the annual average DR potential equal to 3.5 GW in industry and up to 3.8 GW in tertiary sector in Germany. In [TL15], the potential of

DR which is available at least for one hour in Germany is estimated to be 6.4 GW. The authors in [BGKR13] identify 1.7 GW shiftable load which is available for at least two hours in Germany. [Ste16] estimates the DR potential capacity in industry and the tertiary sector in Germany in the order of 10% of peak load (approximately 7 GW). Besides, authors in [EGH+12] estimate that the potential DR capacity in Germany in 2012 lies in the range between 12.5 GW and 14 GW. They argue that by assuming a fixed demand, the potential DR capacity in 2020 and 2030 would remain within the same range since an increase in DR resources thanks to electric cars will be compensated by a decrease in DR provided by night storage heating systems. However, by assuming the annual demand growth between 2010 and 2030, potential DR would be higher than 14 GW for the period between 2020 and 2030.

This study shows that maximum amount of optimal economic DR with a 75% confidence interval is 8 GW in 2020 and 12 GW in 2030 (see Figure 5.10). Hence, the optimal economic DR in the German electricity market would be lower than estimated potential for DR capacity in [EGH+12]. The maximum amount of optimal emergency DR with a dispatch price of 2000 €/MWh is also lower than potential DR (see Figure 5.10). The average optimal emergency DR with a dispatch price of 500€/MWh is 5 GW in 2020 and 12 GW in 2030. Although the average optimal emergency DR is still lower than potential DR, there is a probability that the volume of optimal emergency DR exceed potential DR. To sum up, the amount of optimal DR capacity, which depends on the type and dispatch price of offered DR, lies in the range of potential DR capacity in Germany. Therefore, to ensure long-term resource capacity proper policies and incentives are needed to fully exploit the DR potential and encourage even more DR participation.

5.4.2 Resource adequacy value of DR

By increasing the demand response penetration in the coming years, one of the important questions for resource adequacy relates to the contribution of DR to the reliability and resource adequacy in an electricity system. Unlike the high availability of conventional generators, DR resources are typically constrained by the number of load curtailment events during a given time. These constraints can potentially limit the resource adequacy value of DR. In this section the impact of DR call limit and DR dispatch limit on the average resource adequacy value of DR capacity in the German electricity market and in presence of 20% share of variable RES in the generation profile is analyzed. It is important to note that this study does not consider the impact of consecutive hours or days that DR may be called.

In order to estimate the contribution of DR to the resource adequacy, system operator would need to consider the risk of exceeding different DR limitations such as maximum number of DR call hours per day in a given year, maximum number of days with DR utilization per year, and maximum amount of MWh dispatched DR per hour or per day in a given year. It is assumed that DR capacity would be dispatched if the load exceeds the reserve margin. Therefore, DR would be dispatched only for reliability purposes in order to avoid blackouts in extreme reliability situations. In this section, DR utilization values reflect the probability-weighted average of DR utilization over a large number of scenarios with varying demand and generation conditions in a given year. The details of modeling the uncertainty in generation and load is explained in the proposed electricity market model in chapter 4. Figure 5.14 shows the average daily DR utilization hours in a given year in presence of different reserve margins in the German electricity market. For instance, the maximum number of DR call hours per day in the reserve margin of 0% is 14 hours per day. By increasing the reserve margin, the maximum daily DR calling hours is decreasing. In the economically optimal reserve margin which is 6.5% of peak load, the maximum number of DR utilization hours is 5 hours per day. Figure 5.15 shows the same results as in Figure 5.14 in a sorted manner and in 60 days with highest DR-call hours per day in order to analyze the impact of a particular maximum DR call hours per day limit on the resource adequacy value of DR. This figure shows that in order to maintain 100% resource adequacy value for DR, the call limit would have to be increased to 14 hours per day at 0% reserve margin, 13 hours per day at 3% reserve margin, and 5 hours per day at 6.5% reserve margin and 1 hour per day at 9% reserve margin. By assuming a maximum 4 hours call per day limit, the resource adequacy value of DR is approximately 16% at the 0% reserve margin, 40% at 3% reserve margin, 65% at 6.5% reserve margin and 100% at 9% reserve margin.

The area under each curve in Figure 5.15 represents the total number of DR call hours in a given year. The total number of DR call hours per year is 318 hours at 0% reserve margin, 153 hours at 3% reserve margin, 29 hours at 6.5% reserve margin and 4 hours at 9% reserve margin. By assuming a maximum 30 hours DR call per year limit, the resource adequacy value of DR in presence of the economically optimal reserve margin would be 100%.

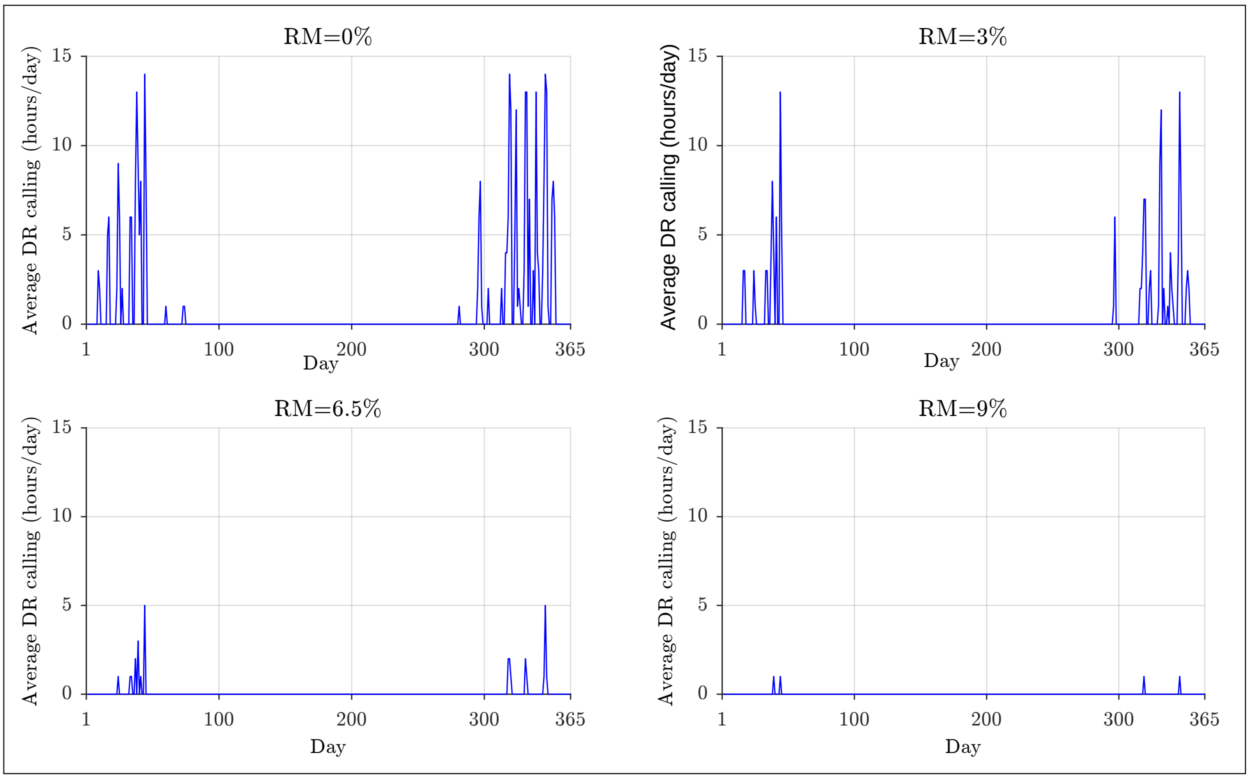

Figure 5.14: Average DR dispatch hours per day at different reserve margins

Another DR call limit could be defined as the number of the days that DR is dispatched should not exceed a particular call-day limit. For instance, according to the results in Figure 5.15 if there is DR call-day limit of 50 days per year, this limit would be exceeded if the target reserve margin is 0%. The maximum number of DR call-days across a year in presence of economically optimal reserve margin is 16 days per year. Under the assumption with 15 days per year call limit, the resource adequacy value of DR is approximately 54% at the 0% reserve margin, 71% at 3% reserve margin, 100% at both 6.5% and 9% reserve margin.

Figure 5.16 shows the average daily dispatched DR in Gigawatt hours at different target reserve margins in 60 highest DR utilization days in the German market. For instance, if there is a DR dispatch limit of 10,000 MWh per day, the DR dispatch limit would be exceeded if the target reserve margin is 3%. The maximum volume of dispatched DR per day at the economically optimal reserve margin is 1,760 MWh per day. Under the assumption of a 1,000 MWh DR

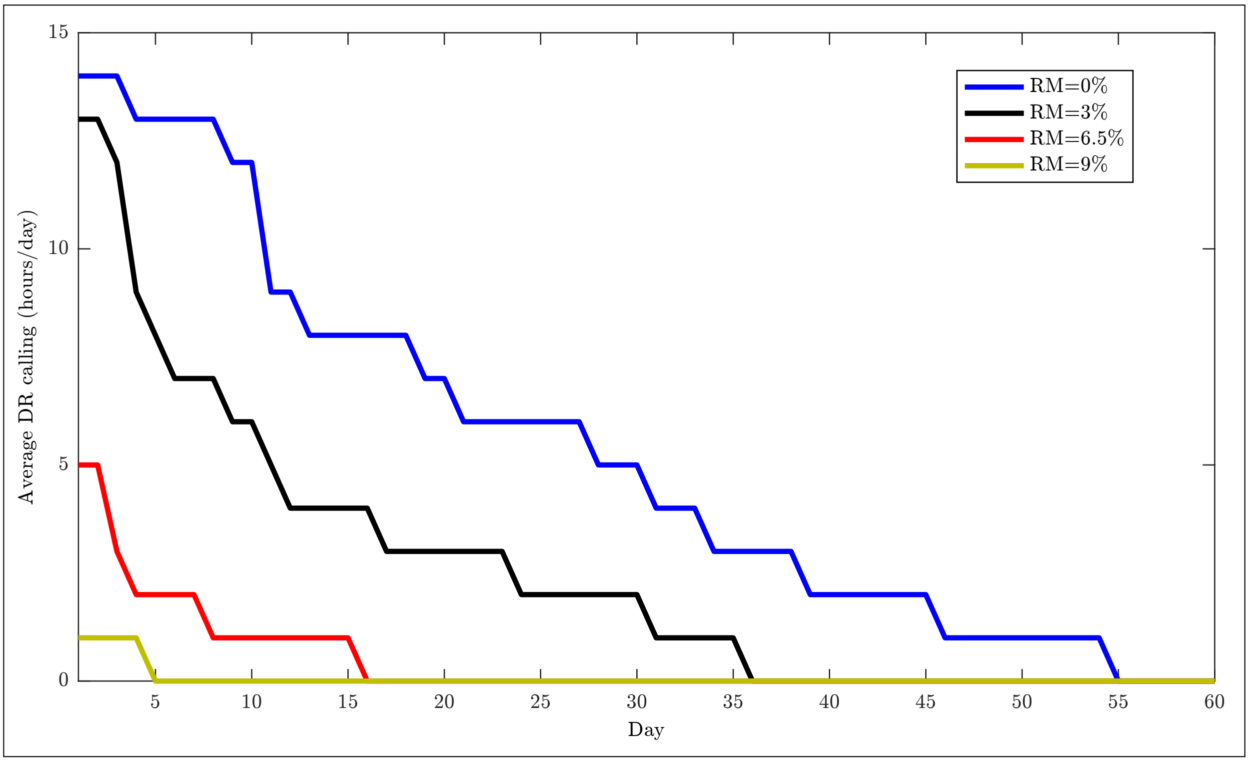

Figure 5.15: Sorted average DR dispatch hours per day and DR dispatch days per year at different reserve margins

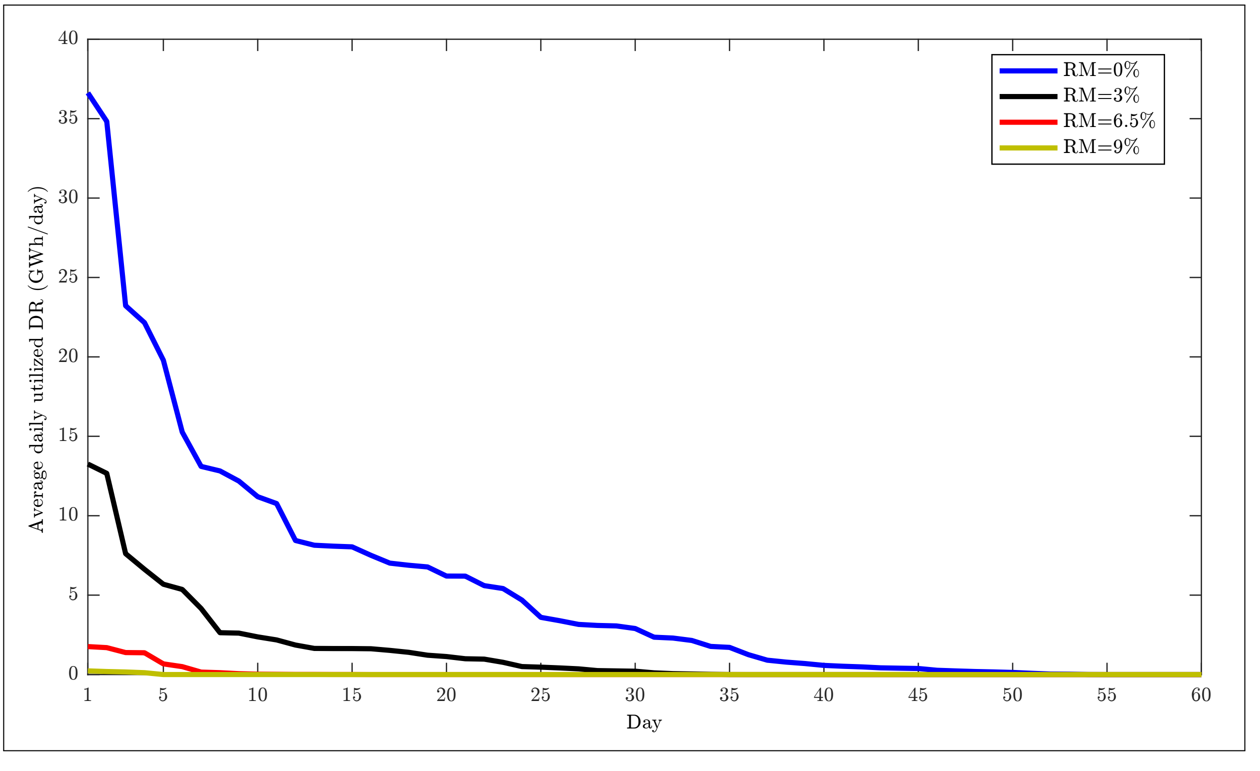

Figure 5.16: Average volume of dispatched DR per day at different reserve margins

utilization per day limit, the resource adequacy value of DR is approximately 2% at the 0% reserve margin, 7% at 3% reserve margin, 20% at 6.5% reserve margin and 100% at 9% reserve margin.

In [HF15], authors argue that the resource adequacy value of DR depends on characteristics of DR program and operating conditions of utilities. According to the[HF15], the estimated resource adequacy value of DR in different electricity markets is given in the following. In California, the resource adequacy value of day-ahead DR programs with voluntary load reductions would be as low as 40% whereas the resource adequacy value of DR provided by air-conditioning load control programs and commercial and industrial DR programs with short response time could be higher than 80%. In Colorado, the resource adequacy value of DR programs with a 4 hours DR call limit per day and a 40 hours call limit per year is around 70%, while DR can be dispatched up to 160 hours per year. In Portland General Electric, the resource adequacy value of direct load control programs is between 70% to 95% and this value of non-automated load reductions is between 40% to 50%.

The resource adequacy value of DR in the German electricity market in presence of the economically optimal reserve margin and with maximum 4 hours dispatch limit per day is 65%, while the resource adequacy value of DR in Colorado in presence of the same dispatch limit is around 70%. The difference in the resource adequacy value of DR across different markets comes from the fact that resource adequacy value of DR mainly depends on the type of provided DR and the characteristics of each electricity market such as share of RES, DR penetration, reserve margin, peak load season and period and the type of DR dispatch constraints.

5.5 Price Cap

In this scenario, the impact of a price cap on the frequency of load shedding events and DR utilization in the German energy-only market is analyzed. The resource adequacy criteria are compared in two different price cap scenarios: The current price cap of 3000 €/MWh in the German market and a price cap equal to the Value of Lost Load (VOLL) which is estimated to be 8500 €/MWh in the German market.

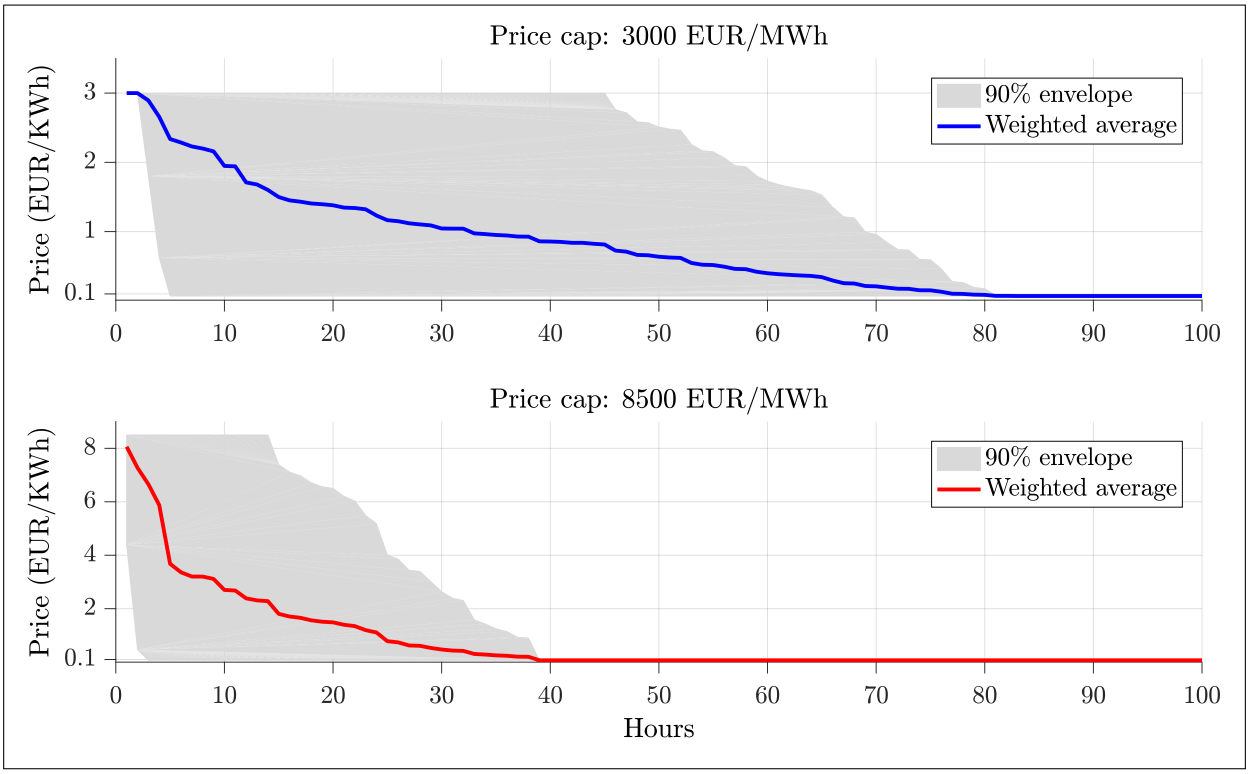

Figure 5.17: Price duration curve at different price cap scenarios in 2028

Figure 5.17 illustrates the 100 highest prices in the price-duration curve for two different price caps in the German market in 2028. The solid lines represent the weighted average of the market prices and the envelopes represent the 90% confidence interval, .i.e. the prices are likely to be within this range with 90% probability. Results show that the optimal duration of scarcity prices and DR utilization period both depend on the price cap. A higher price cap in the market leads to a lower probability of DR utilization and outages. For instance, the optimal load shedding plus DR utilization period in the German energy-only market with the current price cap is estimated to be situated at 80 hours in 2028. For the German market with the price cap equal to VOLL this period is in turn estimated to be equal to 40 hours. A lower number of hours is caused by the fact that market prices are suppressed in the presence of a low price cap and all generators require longer scarcity period or DR utilization period in order to benefit from high prices to recover their investment costs. Therefore, the frequency of both scarcity prices and DR utilization events show a negative correlation with the price cap in the market.

6 Resource Adequacy and Generation Expansion Costs

6.1 Introduction

In this chapter the generation capacity expansion costs in the German electricity market are analyzed and reserve margins associated with standard reliability metrics, economically optimal and equilibrium reserve margins in this market are estimated. First, the main reliability standards in the German electricity market are studied and the reserve margins required to achieve these reliability standards are determined. Subsequently, economically optimal and equilibrium reserve margins are estimated and the sensitivity of these reserve margins to different market parameters is assessed. Finally, the impact of demand response on the optimal reserve margin is analyzed. The main questions which are addressed in this chapter include:

- What is the economically optimal reserve margin in the German electricity market? and what are the economic and policy implications of the optimal reserve margin?
- What are the required reserve margins to meet standard resource adequacy targets defined based on LOLP, LOLH and EUE? And, are they consistent with the economically optimal reserve margin?

6.2 Resource Adequacy Metrics

Resource adequacy metrics assess the ability of an electricity system to provide long-term adequate supply in meeting electricity demand. In literature a variety of resource adequacy metrics are used to measure the generation reliability in electricity markets. Typical metrics of resource adequacy analysis include loss of load probability (LOLP), loss of load expectation (LOLE), loss of load hours (LOLH) and expected unserved energy (EUE). LOLP is the probability that at least one of the consumers is interrupted due to lack of electricity generation. The LOLP value depends on the probability of extreme events that affect the supply and demand balance in the market. For instance, cold winter days or hot summer days, unexpected outage by large power plants, low generation volumes from RES and a high load forecast error would lead to a higher probability of load shedding. LOLE represents the expected number of days per year that supply is not sufficient to meet demand and is calculated as the sum of 365 daily maximum LOLPs. LOLH represents the expected number of load shedding hours and is calculated as the sum of hourly LOLPs. For example, 2 hours of firm load shedding in one day results in a LOLH of 2 and LOLE of 1. Therefore, the LOLE of 0.1 could be equal or less than 2.4 hours of LOLH in a year. All the metrics briefly described above however do not provide any information about the size of load shed or the volume of unserved electricity. Therefore, expected unserved energy (EUE) metric is applied to measure the expected energy in MWh which is not delivered to customers due to shortage in generation.

Resource adequacy targets in most electricity markets are defined based on the reliability metrics mentioned in the last paragraph. The resource adequacy target in Scandinavian countries is equal to 0.001% LOLP [Nod09]. The reliability standard in France, the Netherlands and the Republic of Ireland is equal to 3 LOLH, 4 LOLH and 8 LOLH, respectively [rel13]. One of the most common resource adequacy targets is set at one outage event in every 10 years. The most common representation of this reliability target considers it equal to an average of 0.1 LOLE per year. This interpretation of one-in-10-years reliability standard is mostly used in North American markets including PJM, MISO, NYISO, Quebec Interconnection and IESO [CW13]. Another interpretation of this reliability target considers it to be equal to 2.4 hours of outage per year. This interpretation is currently used by Southwest Power pool in the USA [Poo10].

Another reliability target which is recommended by the North American Electric Reliability Council NERC is defined based on the expected unserved energy (EUE) [NER10]. For instance, Australian National Energy Market (NEM) uses the reliability target equal to 0.002% of unserved energy [NSP+14]. This resource adequacy target refers to the size of the lost load in MWh and covers the limitations of other reliability targets based on LOLE and LOLH. In [NSP+14] EUE metric is considered as a robust and meaningful resource adequacy metric which considers the size of the electricity market in its reliability measurements. In other words, EUE represents the ratio of the size of unserved load to the total load while neither of LOLP, LOLE and LOLH metrics considers the size of outage.

6.2.1 LOLP Estimation Method

The loss of load probability (LOLP) is used as a standard reliability metric to measure reliability in different electricity generation and load scenarios. According to the proposed model in chapter 4, the hourly generation and load values are modeled as random variables with normal probability distribution functions. Each hourly generation value is modeled as a normally distributed random variable, which is defined as $G \sim N(m_G, \sigma_G^2)$ with mean m_G and variance σ_G^2. The mean value m_G is the expected hourly generation volume by considering the uncertainty of conventional generation outage. The variance value σ_G^2 is determined by considering the variability of generation from variable RES. In the same way, each hourly load value is modeled as a normally distributed random variable, which is in turn defined as $D \sim N(m_D, \sigma_D^2)$ with mean m_D and variance σ_D^2. The mean value m_D is the expected hourly load volume by considering the uncertainty of demand growth rate and load forecast error. The variance value σ_D^2 is determined by considering the variances of weather-related load uncertainty and load forecast error. The generation and load random variables are independent as the sources of uncertainty for these variables are independent. The LOLP is defined as the probability that generation volume becoming lower than demand volume. In this study, the stress-strength reliability estimation for the two random variables is utilized to calculate the LOLP. This reliability estimation method calculates the maximum likelihood estimation of the $Pr(G < D)$, which is given in the equation 6.1. $\Phi(*)$ is defined as the cumulative distribution function of the standard normal distribution with zero mean and a standard deviation of 1.

$$LOLP = Pr(G < D) = \Phi((m_D - m_G)/\sqrt{(\sigma_G^2 + \sigma_D^2)}) \tag{6.1}$$

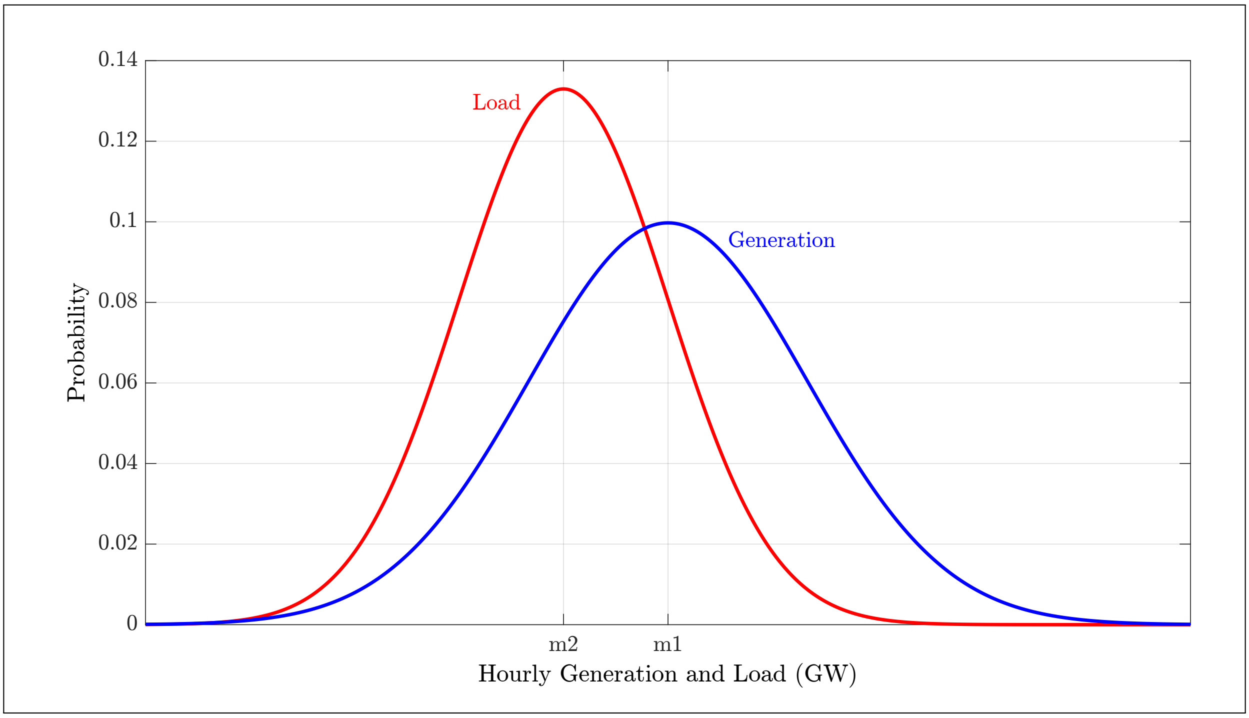

Figure 6.1: Reliability calculation with normal generation and load portability distributions

6.3 Reserve Margin Calculation

Increasing penetration of wind and PV electricity generation and demand response resources produced different approaches to calculating reserve margins in different markets. Some of the markets consider the nameplate capacity of each generator as its contribution to the reserve margin. Others such as NYISO, PJM, and MISO consider the capacity credit of each generator in reserve margin calculations [NSP+14]. In this study the capacity credit of each generator is considered in reserve margin calculation. The annual reserve margin RM is defined in the equation 6.2 while $ECAP$ is the effective capacity of each generation technology and $max(load)$ is the annual peak load. $ECAP$ is equal to the capacity credit of each generation technology which represents the available generation capacity of a generator during low-reliability and peak load events. In other words, ECAP represents the contribution of each generator to the final delivered resource adequacy and reliability in the market. Consequently, the calculated reserve margin is consistent with the resource adequacy definition. The effective capacity of dispatching generators considers the forced outage of these generators during low-reliability events and usually lies in the range between 85% and 100% of the total installed capacity of these generators. The forced outage of conventional generators in the German electricity market is discussed in 4.4.4.2 and the histogram of forced outages in 2012 is depicted in Figure 4.11. The effective capacity of variable renewables such as solar and wind is much lower than the installed capacity of these resources. The effective capacity or capacity credit of variable RES in the German electricity market, which is calculated in 4.4.4.1, is equal to 4% of the total installed capacity of these generators in 2012. Figure 4.10 shows the by increasing the variable RES penetration to 50% in 2042, capacity credit of variable RES is decreasing to 2.3% of their installed capacity.

$$RM = (ECAP - max(load))/max(load) \tag{6.2}$$

6.4 Optimal Reserve Margins in Different Reliability Standards

Reserve margins that ensure different standard reliability targets in the German electricity market are calculated in this section. In Figure 6.2, the variation of LOLE with a reserve margin is depicted. Based on the LOLP calculation, the German electricity market needs to have a 9.2% reserve margin in order to meet LOLE standard reliability target of 0.1 (1 events in 10 years). Load shedding events at this level of reserve margin are expected to occur once every 10 years which will last for 1.5 hours and 468 MWh of load will not be served. Key factors that have an impact on LOLE are the uncertainties in both supply and demand side of the market. In this study these factors include the variations in the capacity credit of renewables and conventional generators, load forecast errors and extreme weather conditions. In case the one-in-10 reliability target is interpreted as 2.4 LOLH, the reserve margin required to fulfill this target is equal to 7.8% of peak load. At this reserve margin level, 3 load shedding events are expected to occur every 10 years and the total amount of load shedding would be 2,340 MWh. The variation of

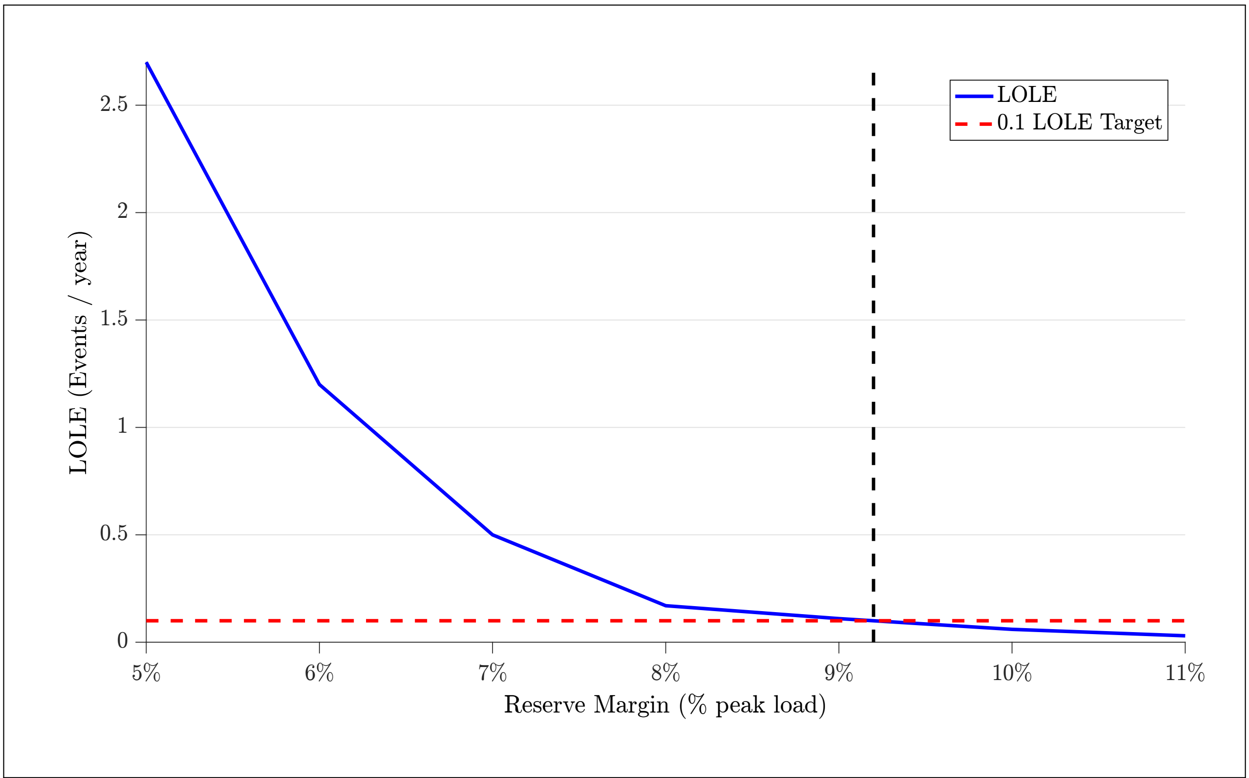

Figure 6.2: Loss of Load Expectation versus reserve margin

loss of load hours with the changes in reserve margin is shown in Figure 6.3. The LOLH curve represents the weighted average of loss of load hours in different generation and load scenarios.

As mentioned above, Expected Unserved Energy (EUE) is another important metric in order to measure the resource adequacy in an electricity market. The EUE-based standard reliability target is defined as EUE equal to 0.001% of total annual load. The variation of EUE versus reserve margin is depicted in Figure 6.4. As is shown, the reserve margin required to ensure the 0.001% EUE reliability target is approximately 7% of peak load. At this reserve margin the size of outage is 4681 MWh which is estimated to occur 5 hours in total per year and the LOLE is about 0.5% event probability per year. Results show that EUE metric requires a lower reserve margin compared to LOLE and LOLH reliability targets. As Germany has a big electricity market with a total annual load in the range of 470 TWh, it is reasonable to use the EUE reliability metric as a base for setting a resource adequacy target.

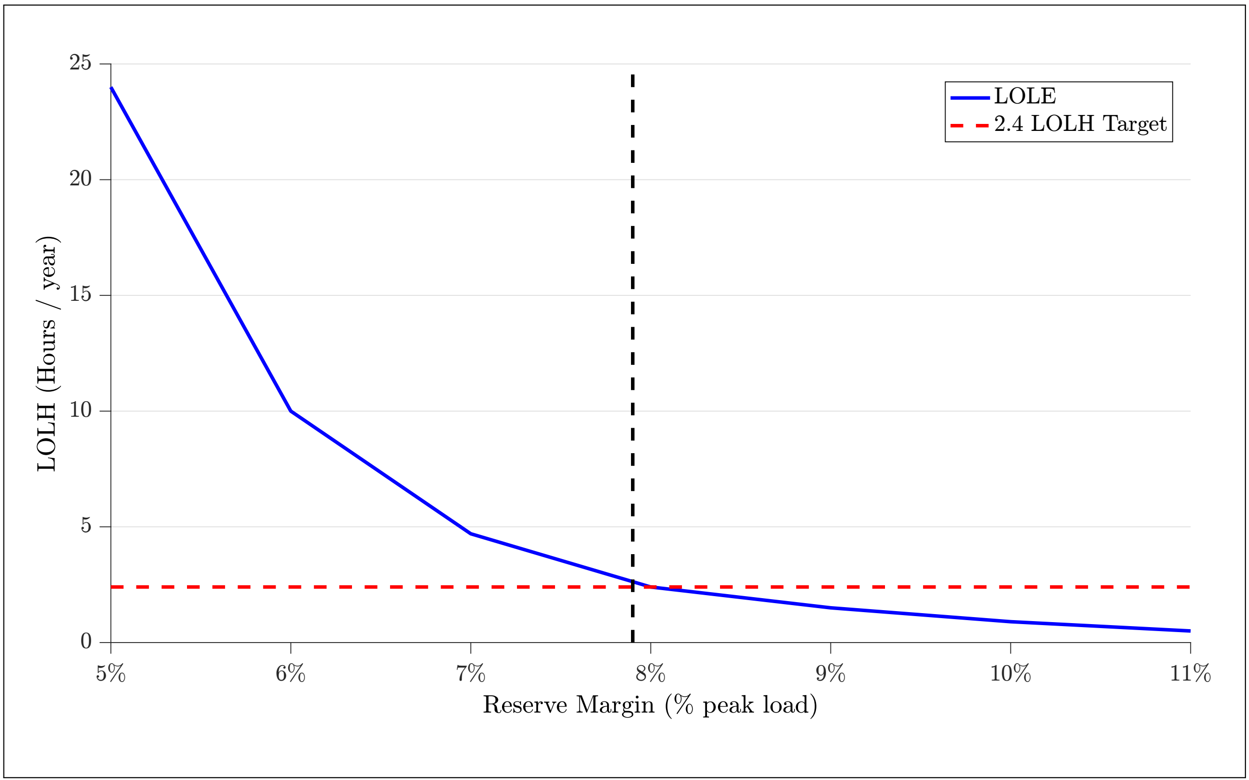

Figure 6.3: Loss of Load Hours versus reserve margin

6.5 Economically Optimal Reserve Margin

In this section the economically optimal reserve margin in the German electricity market is estimated. The economic value of resource adequacy at each reserve margin level is estimated by calculating the total electricity generation cost at that level. Total generation cost represents the major resource adequacy-related costs of the electricity systems from the societal point of view and consists of the existing generation capacity cost and generation capacity expansion cost. At the economically optimal reserve margin, the total generation cost of electricity system is minimum. The revenue-cost transfer between different electricity market participants is not considered in the economic reserve margin calculation. The reason for it is that electricity trade during few hours of extreme scarcity only represents a wealth transfer from consumers to producers rather than social costs. Therefore, this approach only minimizes net social costs of electricity generation and does not address ways in which costs and revenues are shared among the players in the system.

The theory of finding optimal volume of installed generation capacity which maximizes the net social benefit of electricity services is mainly introduced in [CCK78] and [DV04]. The total

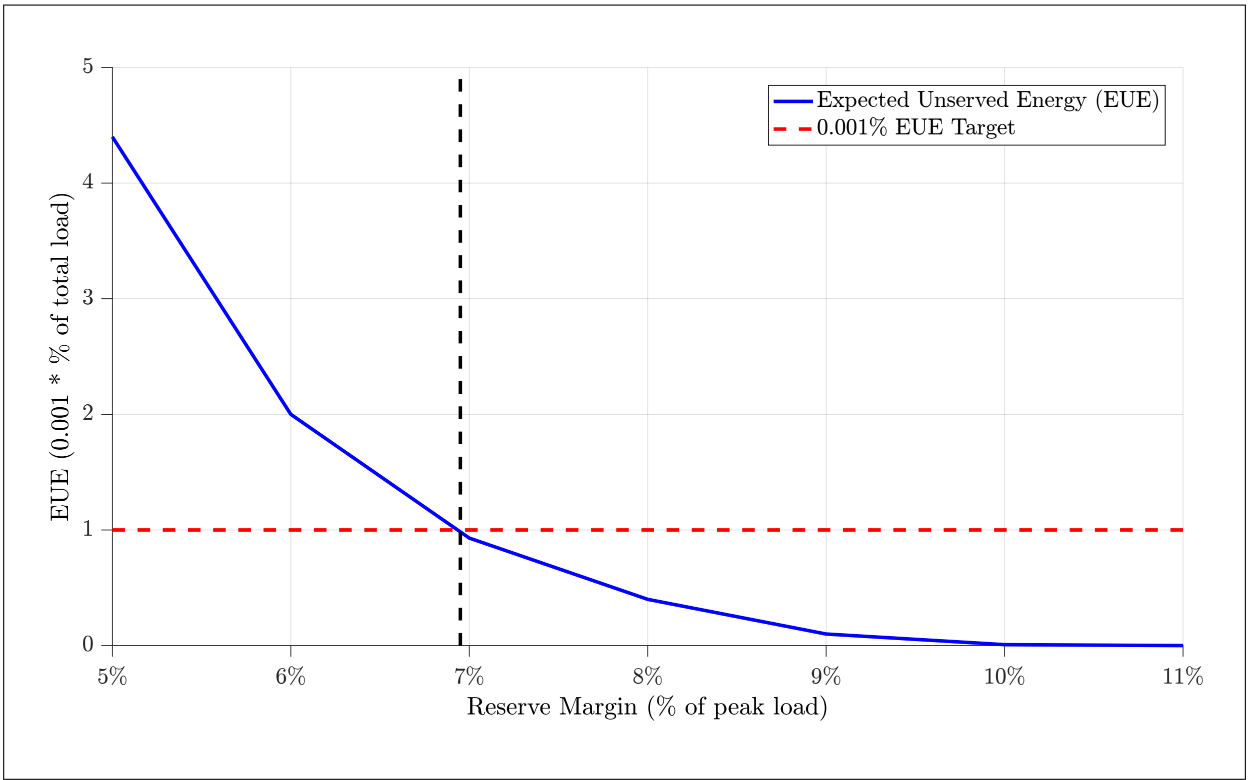

Figure 6.4: Normalized EUE versus reserve margin

consumer and producers surplus, total social cost of outages and cost of generation capacity are formulated as a function of reserve margin in [DV04]. Then, the asymmetric distribution of the net social benefit around the optimal generation capacity is represented.

In this study, two main components of total generation cost (C_{total}) are the cost of already installed or existing generation capacity ($C_{existing\,capacity}$) and cost of generation capacity expansion ($C_{expansion}$). The total generation cost is calculated by assuming the continued existence of the current power plant set. The existing generation capacity denotes to the generation capacity which is required to meet average peak load in the market. Therefore, existing generation capacity cost is a fixed value which is independent from the additional reserve margin. Generation capacity expansion refers to the additional generation capacity above the average peak load which is built to reduce the probability of outage in electricity markets. Expansion cost includes the cost of unserved load ($C_{unserved\,load}$) and the annual long-term marginal cost of new additional generation capacity ($C_{new\,capacity}$). The total generation expansion cost is measured from the starting point of 0% reserve margin in the market. At the reserve margin of 0%, the cost of new additional generation capacity is zero, while the average cost of unserved load is relatively high. By increasing the reserve margin, the cost of unserved load is decreasing and the cost of new additional capacity is increasing.

The total generation cost is formulated in Equation 6.3. The cost of unserved load is a function of the value of lost load (VOLL) in the market. The VOLL in the German electricity market is estimated to be 8500 €/MWh. The cost of unserved load at each reserve margin level is calculated by multiplying VOLL by the expected amount of expected unserved energy (EUE). As already discussed in 4.3, new additional generation capacity is assumed to be allocated in new combined cycle gas turbine (CCGT) power plants. The annualized fixed cost of new CCGT power plants or the cost of new entry (CONE) for CCGT plants is assumed to be 59,500 €/MW.yr in the base-case scenario. The volume of new generation capacity is defined as the amount of available generation capacity above the capacity needed to meet peak load and it is calculated by multiplying the reserve margin (RM) by the peak load. The cost of new generation capacity is calculated by multiplying the CONE of CCGT plants by the volume of new additional capacity.

The total generation cost is minimum at the economically optimal reserve margin. Equation 6.4 describes the relation between the decreasing rate of expected unserved energy (EUE) with VOLL and CONE at the economically optimal reserve margin. The rate that the cost of unserved load is decreasing at the economically optimal reserve margin is equal to the cost of new entry multiplied by the peak load.

$$\begin{aligned} C_{total} &= C_{expansion} + C_{existing\,capacity} \\ C_{expansion} &= C_{unserved\,load} + C_{new\,capacity} \\ C_{unserved\,load} &= VOLL * EUE \\ C_{new\,capacity} &= CONE * RM * max(load) \end{aligned} \tag{6.3}$$

$$min\ C_{total} \Longrightarrow \frac{\partial C_{total}}{\partial RM} = 0 \Longrightarrow \frac{\partial EUE}{\partial RM} * VOLL = -CONE * max(load) \tag{6.4}$$

The variation of total generation expansion costs versus the reserve margin is demonstrated in Figure 6.5. The cost of new additional capacity, which is represented by the red curve, is zero

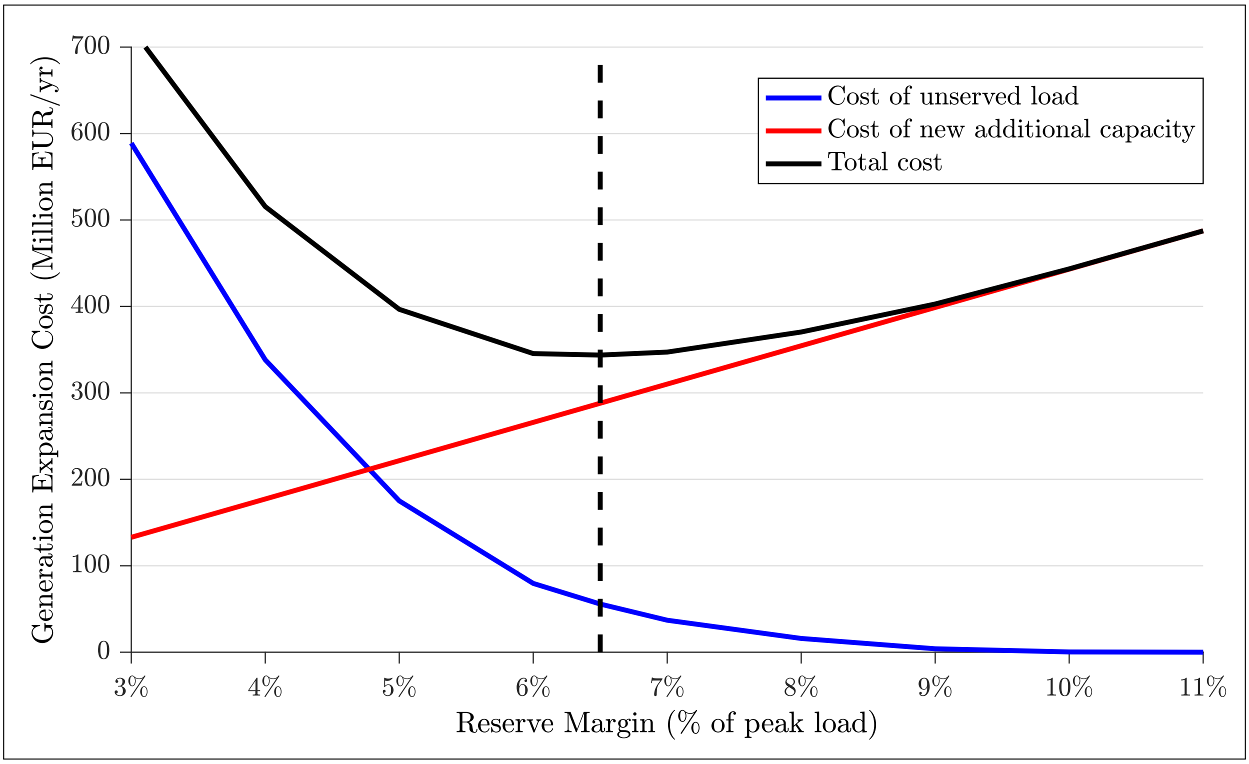

Figure 6.5: Total generation capacity expansion costs versus reserve margin

at 0% reserve margin and an increase in the reserve margin results in a higher cost of additional installed capacity. The blue curve shows how the cost of unserved load changes due to the variation of the reserve margin in the market. At a lower reserve margin in the market, the average annual cost of unserved load is relatively high due to a higher volume of unserved load. An increase in the reserve margin results in less volume of unserved load and, consequently, a lower cost of load shedding. However, the rate of decrease in unserved-energy-related costs is higher than the rate of increase in the capital cost of installed capacity. The sum of these two costs makes up the total generation expansion cost as is shown with the help of the black curve. Furthermore, the cost of unserved load has a higher share at lower reserve margins and the cost of new additional capacity has a higher share at high reserve margins. Figure 6.5 shows that the economically optimal reserve margin in the German electricity market is equal to 6.5% of peak load, which is the reserve margin associated with minimum cost of generation capacity expansion. This 6.5% economically optimal reserve margin is slightly lower than the 7% reserve margin based on the 0.001% normalized EUE target and lower than the 9.2% reserve margin based on the 0.1 LOLE reliability target.

Total generation expansion cost variation around the economically optimal reserve margin is relatively low. The reason is that the increasing cost of new additional capacity is compensated to a large extent by the reduced cost of load shedding events around the optimal reserve margin. For instance, by increasing the reserve margin from 6.5% to 8%, the total system costs increase by approximately 7% which is equal to 26 Million €. An increase in the reserve margin from 6.5% to 9% results in an approximately 16% increase in total expansion cost which is equal to 56 Million €. This cost can be interpreted as the total cost of implementing a strategic reserve mechanism by using existing or new gas-fired power plants in order to increase the reserve margin in the German market. Therefore, in presence of high risk-aversion to low-reliability events, the additional cost of a capacity mechanism would be justified.

6.5.1 Sensitivity Analysis of the Economically Optimal Reserve Margin

As mentioned above, the amount of VOLL and the capital cost of new CCGT plant in the German electricity market in the base case scenario are assumed to be 8,500 €/MWh and 59,500 €/MW.yr, respectively. However, these parameters which are derived from the literature might vary in different market conditions and it is necessary to measure how sensitive the economically optimal reserve margin is to these parameters. For instance, if investors decide to build new generation capacity in the form of Open-Cycle Gas Turbine (OCGT) power plants, the annual fixed cost of these new plants would be lower than that of CCGT plants. In order to perform a sensitivity analysis, three scenarios including the base case, high Cost of New Entry (CONE) and low CONE are defined. The annual fixed cost of new entry (CONE) in the base case scenario is 59.5 €/KW.yr, and the annual fixed cost in low CONE and high CONE scenarios is equal to 30 €/KW.yr and 90 €/KW.yr, respectively. Figure 6.6 shows the sensitivity of the economically optimal reserve margin to the VOLL and capital cost of new installed capacity. The figure to the right shows how CONE affects the economically optimal reserve margin, while the VOLL is considered to be fixed at 8,500 €/MWh. The economically optimal reserve margin in high CONE and low CONE is 6% and 7.3% of peak load, respectively. Results show that a higher CONE results in a lower economically optimal reserve margin since in the presence of a high CONE, new additional capacity is more costly, which shifts the total costs curve to the left. As a result, the economic reserve margin becomes lower compared to base case scenario to avoid the high costs of new additional capacity. In contrast, in the presence of a lower CONE, the cost curve is shifted to the right and the economic reserve margin becomes higher than that in the base case scenario.

The plot on the left side of Figure 6.6 shows the variation of the economical reserve margin by the VOLL, while the CONE is assumed to be fixed at 59,500 €/MW.yr. In order to assess the sensitivity of the optimal reserve margin to the VOLL, three scenarios are defined. In the base case scenario, the VOLL is assumed to be 8,500 €/MWh. The VOLL in the high-VOLL and low-VOLL scenarios are assumed to be 12,000 €/MWh and 6,000 €/MWh, respectively. The economical reserve margins in base case, high-VOLL and low-VOLL scenarios are equal to 6.5%, 7% and 6%, receptively. It is concluded that an increase in the VOLL leads to an increase in the economical reserve margin. A higher VOLL in the market increases the cost of unserved energy and leads to a higher reserve margin needed to avoid higher costs of load shedding.

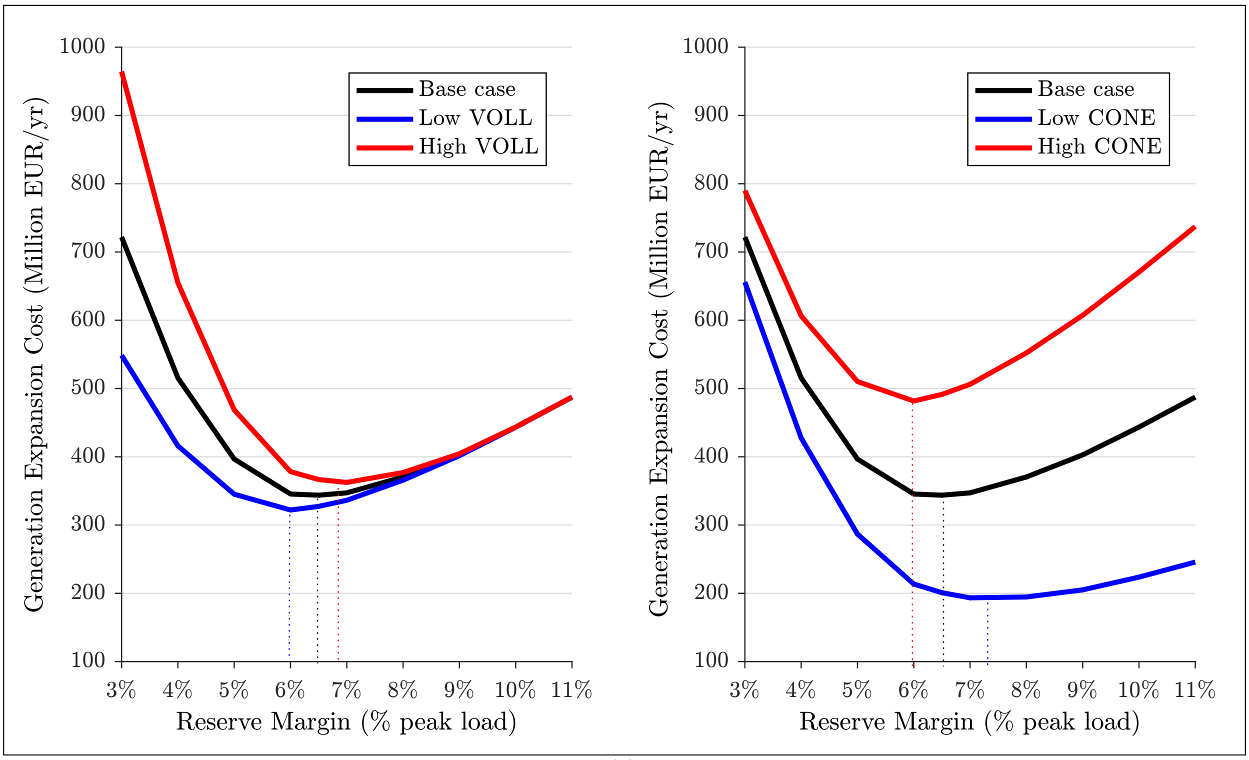

Figure 6.6: Total costs with varying VOLL and CONE

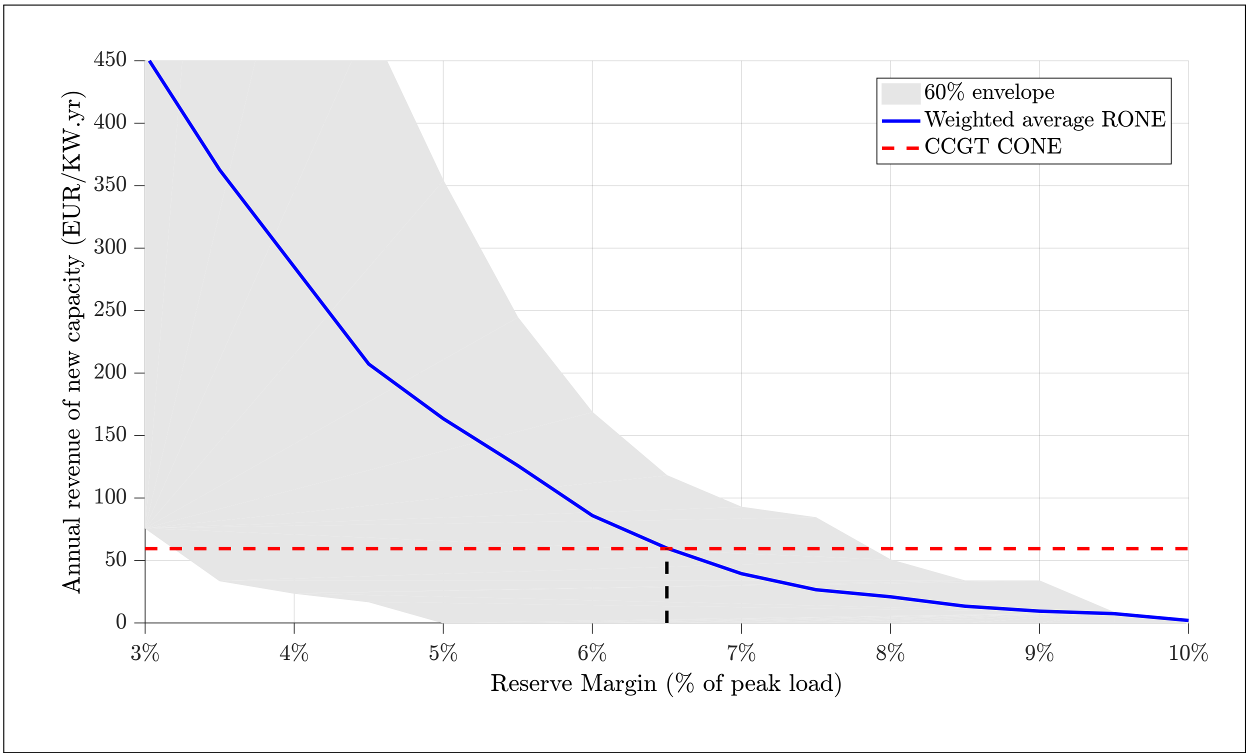

Figure 6.7: Average annual RONE and CONE for new installed capacity

6.6 Equilibrium Reserve Margin

In this section the equilibrium reserve margin in the German electricity market is estimated. In energy-only markets at the equilibrium reserve margin point the annual expected revenues and annual expected costs of new installed capacity are equal. The amount of wealth transfer from consumers to producers during scarcity situations is optimal in a competitive market. If the wealth transfer during scarcity conditions becomes higher than the optimal volume, it means that new generation capacity is profitable in the market and additional new capacity will be added into the market. The addition of new generation capacity results in a higher reserve margin and a reduction in the wealth transfer. If the latter becomes lower than the optimal value, marginal producers will face difficulties recovering their capital costs.

As explained in Chapter 4, the German electricity market is considered as an energy-only market and there is no mandatory reserve margin in such markets. Therefore, the level of investment in new generation capacity depends on market prices alone. Market prices are required to be high enough to provide adequate returns on investment for existing installed capacities. If the reserve margin is higher than the equilibrium reserve margin, new installed capacity will not receive sufficient returns to cover its capital costs. The revenue and cost of new entrants is depicted in Figure 6.7. The weighted average equilibrium reserve margin in the German electricity market is estimated to be 6.5% of peak load, which is equal to the optimal reserve margin in the base case scenario. Taking into account all uncertainties in the Revenue Of New Entry (RONE) resulting from different generation and load scenarios, the equilibrium reserve margin varies between 3% to 8% of peak load within the 60% probability envelope.

7 Conclusion

7.1 Conclusion and Policy Implications

The issue of resource adequacy has recently been on top of the political agenda in the German electricity market. The problem is that incentives for investment in new generation capacity are not high enough to ensure the long-term generation adequacy. The continuing transformation towards higher shares of renewable energy sources (RES) in the electricity generation profile exacerbates the resource adequacy problem in the German electricity market as well. Therefore, there is an ongoing discussion on which type of future electricity market design could ensure the long-term generation adequacy. This study provides an evaluation of ways in which an energy-only market design can guarantee long-term resource adequacy in the German market. To this aim, a probabilistic model is proposed to conduct the economic and reliability analysis of generation resource adequacy in the German energy-only market. The proposed model evaluates the resource adequacy condition by simulating all reliability outcomes in the German market which resulted from uncertainties in supply and demand. Therefore, the probability and size of extreme events and their impact on resource adequacy is properly captured. The model determines the optimal annual generation investment in new capacity by estimating the expected profitability of investing into new capacity in the market. The optimal generation investment for both risk-neutral and risk-averse investors is calculated by solving a stochastic optimization problem. As a result, an economically optimal resource adequacy condition, an economic and equilibrium reserve margin, the impact of demand response (DR), price caps and investment risk on the long-term resource adequacy condition in the German energy-only market are analyzed. Based on the main findings and results, the research questions of this study are addressed below.

How much value for resource adequacy do variable renewables in Germany possess?

The capacity credit of variable RES in the German electricity market and in the presence of a 20% share of variable renewables in the generation profile in 2012 is estimated to be approximately 4% of their installed capacity. This shows that there is a very low correlation between both solar and wind generation with peak load in Germany. By increasing the renewables penetration in the market, the capacity credit of variable RES is decreasing. The capacity credit of variable RES drops to 2.3% when these have a 50% share of the generation profile in the German market. Due to a low capacity credit of variable RES in Germany, significant amounts of new conventional generation capacity (equal to approximately 96% of variable RES installed capacity) would still be required to be built in parallel with variable RES in order to maintain the same level of resource adequacy in the market. The electricity system is bound to incur considerable costs due to the additional investment into conventional generation required to offset the low capacity credit of variable RES. Therefore, an economically efficient electricity market requires sufficient flexibility in the electricity supply which could mainly be offered by demand response or storage facilities.

What is the risk-neutral economically optimal reserve margin in the German energy-only market? What are the economic and policy implications of the optimal reserve margin?

The risk-neutral economically optimal reserve margin for the German electricity market is estimated to be in average equal to 6.5% of the peak load. It means that the total cost of the electricity generation from the societal point of view is minimum at this reserve margin. The equilibrium reserve margin in the German energy-only market is further equal to the risk-neutral economically optimal reserve margin. At the equilibrium reserve margin of 6.5%, total revenues and costs for new installed capacity are equal and new generation capacity is able to recover its short-term and long-term costs. Therefore, the German energy-only market with a 6.5% reserve margin is an optimal market design in terms of minimizing the total electricity system costs and attracting economically optimal investment in generation capacity to ensure long-term resource adequacy. In case if the economic efficiency and long-term resource adequacy are the only policy objectives for policymakers, an energy-only market with economically optimal reserve margin of 6.5% is the best choice of market design for the German electricity system.

In the generation cost analysis, the cost of load shedding is estimated based on the value of lost load (VOLL) which represents consumers' willingness to pay in order to avoid a disruption in their electricity services. However, the cost of low-reliability events such as load shedding might be higher from social, political and policymakers' perspective. For instance, the expected unserved energy at the economically optimal reserve margin is 6,554 MWh and with assumed VOLL of 8,500 €/MWh, the total implied cost of load shedding events would be approximately €55.7 million. This cost is already considered in the economically optimal reserve margin calculations. Nevertheless, the cost of load shedding from a public perspective might be much higher than 8,500 €/MWh. It means that if policymakers and investors have strong risk-averse preferences and do not tolerate any low-probability load shedding events, the mandatory reserve margin will be higher than the economically optimal reserve margin. A higher reserve margin leads to a distortion in the cost-revenue equilibrium for new installed capacity making it impossible for new generation capacity to recover its capital costs. Therefore, despite the reduced probability of load shedding in an energy-only market with a mandatory reserve margin, such a market setup does not ensure long-term resource adequacy due to its inability to provide sufficient revenues for new generation capacity. As a consequence, a capacity mechanism would be required to be implemented in order to reduce the risks associated to the low-reliability and high-price events.

Findings show that the derivative of total costs around the optimal reserve margin is low. In other words, the rate at which total costs increase around the optimal reserve margin point is slow, since the increasing cost of new capacity is compensated to a large extent by the reduced cost of load shedding events around the optimal reserve margin. This study shows that by increasing the reserve margin from 6.5% to 8%, the average generation expansion costs increase approximately 26 million €per year (equal to 7% of annual generation expansion costs). This cost can be interpreted as the total cost of implementing a capacity mechanism such as strategic reserve by using existing or new gas-fired power plants to increase the reserve margin from 6.5% to 8% in the German market. Therefore, in presence of strong risk-aversion to low-reliability events, the additional cost of a capacity mechanism would be justified.

What are the required reserve margins to meet standard resource adequacy targets in the German electricity market? Are they consistent with the economically optimal reserve margin?

Based on the LOLP calculation, the German electricity market needs to have a 9.2% reserve margin in order to meet LOLE standard reliability target of 0.1 (1 events in 10 years). In case the one-in-10 reliability target is interpreted as 2.4 LOLH, the reserve margin required to fulfill this target is equal to 7.8% of peak load. The reserve margin required to ensure the 0.001% EUE reliability target is approximately 7% of peak load. At this reserve margin the size of outage is 4681 MWh which is estimated to occur 5 hours in total per year. This study shows that compared to LOLE and LOLH metrics, the required reserve margin to fulfill 0.001% EUE metric is more consistent with economically optimal reserve margin. Besides, this metric provides a more robust and meaningful measure of resource adequacy which considers both the size of outage and the size of electricity system. As Germany has a big electricity market with a total annual load in the range of 470 TWh, it is reasonable to use the EUE reliability metric as a base for measuring resource adequacy.

What is the optimal volume of emergency and economic demand response capacity to ensure generation resource adequacy in the German electricity market?

The German energy-only market with optimal capacity of either economic or emergency DR capacity can ensure resource adequacy and provide enough incentives for new investment meant to avoid load shedding events in future. The amount of DR capacity required for safeguarding resource adequacy, which is called as the economically optimal DR capacity as well, depends on five main factors: installed generation capacity, available DR capacity or DR penetration level, DR dispatch price, price cap, and the share of variable renewables in the generation profile. Optimal volume of emergency DR is higher in case its dispatch price is low. The level of the latter determines whether the optimal volume of emergency DR is higher or lower than that for economic DR. In the presence of 50% generation from variable RES, the average optimal capacity of emergency DR with the dispatch price of 500 €/MWh amounts to 15 GW with the demand response utilization period of 135 hours. In case the dispatch price of emergency DR is 2000 €/MWh, the optimal capacity decreases to 10 GW while the utilization period will be reduced to approximately 30 hours of utilization time. In turn, the optimal capacity of economic DR is 10 GW and the DR utilization time is 40 hours, respectively. Additionally, the amount of optimal DR is increasing alongside the rising share of variable renewables in the market. When the share of variable RES rises from 30% in 2022 to 50% in 2042, the average optimal economic DR capacity increases from 5 GW to 10 GW. The average optimal capacity of economic DR in the presence of 50% generation from variable renewables in 2042 lies in the range between 6.5 GW and 14.25 GW with a 75% confidence interval. The optimal volume of DR capacity in the German electricity market which is estimated in this study lies within the range of the estimated DR potential for Germany in literature. Therefore, to ensure long-term resource capacity proper policies and incentives are needed to fully exploit the DR potential and encourage even more DR participation.

How big is the resource adequacy value of demand response in the German electricity market?

Unlike generally high availability of conventional generators, DR resources are typically constrained by the number of load curtailment events during a given time which can potentially limit their value for resource adequacy. System operator would need to consider the risk of exceeding different DR limitations in order to estimate the contribution of DR to resource adequacy. The value of DR for resource adequacy value of DR mainly depends on the characteristics of a DR program and the dispatch limitations of procured DR. DR dispatch limitations can be defined as maximum DR-call hours per day limit, maximum DR-call hours per year limit, and maximum MWh dispatched DR per day limit. In presence of the economically optimal reserve margin and 20% share of variable RES in the German market, the total number of DR call hours in a given year is 29 hours, the maximum number of DR call per day is 5 hours and the maximum number of dispatched DR per day is 1,760 MWh/day. Therefore, any DR dispatch constraint which is lower than these values will result in a resource adequacy value of less than 100% for DR. In the presence of a fixed DR dispatch constraint, higher reserve margin results in a higher value of DR for resource adequacy value. For instance, by considering a limit of maximum 4-hour call per day for DR capacity, the average resource adequacy value of DR is approximately 16% at 0% reserve margin, 40% at 3% reserve margin, 65% at 6.5% reserve margin and 100% at 9% reserve margin. Besides the above mentioned factors, the resource adequacy value of DR depends on the operational characteristics of the market such as the share of variable RES, DR penetration level, installed generation capacity, and peak load season.

What is the impact of investment risk and price cap on long-term resource adequacy? How sensitive are resource adequacy criteria to these factors?

While the optimal weighted average profit of new capacity in the risk-neutral investment is equal to zero, this value is equal to 55,000 €/MW.year in case of risk-averse investment with the risk-aversion factor of 0.5. Risk-averse investors thus have a higher marginal profitability and are less vulnerable to fluctuations and uncertainties in the market compared to risk-neutral investors. Besides, risk aversion leads to a higher and wider range of possible load shedding and demand response utilization periods. This can be explained by the fact that the optimal capacity volume installed by risk-averse investors is lower than that of risk-neutral investors, which results either in a greater DR utilization or a greater number of load-shedding hours. Additionally, initial overcapacity in risk-averse scenarios results in a greater delay in new investment compared to the risk-neutral scenario.

Increased deployment of DR capacity and load shedding lead to higher market prices and, consequently, to higher inframarginal rents for new generation capacity, which secures their profitability and cost recovery. In the presence of optimal installed generation capacity, higher DR capacity results in shorter load shedding periods. Therefore, scarcity periods and the volume of DR capacity negatively correlate with each other. However, the optimal duration of scarcity prices and DR utilization periods both depend on the stipulated price cap level. A higher price cap in the market leads to a lower probability of DR utilization and outages. This is due to the fact that market prices are suppressed in the presence of a low price cap and all generators require longer scarcity periods or DR utilization periods in order to benefit from higher prices and to recover their investment costs. By raising the price cap from 3,000 €/MWh to 8,500 €/MWh and in the presence of a share of 40% of generation from variable RES, the optimal load shedding plus DR utilization period in the German energy-only market decreases from 80 hours to 40 hours.

7.2 Outlook and Future Work

This study presents a quantitative analysis of resource adequacy in the German electricity market. The resource adequacy problem still presents an ongoing discussion in Germany and its neighboring countries. Policymakers are trying to identify the most economically efficient approach to ensure long-term generation adequacy. Some suggestions for the future work include the following:

- The capacity credit of variable RES is estimated based on the available renewable generation data in 2012 and 2013. As the level of RES penetration in Germany is rapidly increasing and the new variable renewable capacity installation is spreading all around the country, the capacity credit of RES is likely to be affected. Hence, including the renewable generation data from 2014 to 2016 will increase the accuracy of calculating the capacity credit of variable RES in German electricity market.

- Cross-border electricity trade with neighboring countries would have a significant impact on resource adequacy in each country. Therefore, the potential of import and export of electricity during low-reliability events must be estimated in order to have a better perspective about the long-term generation adequacy in Germany. Besides, considering the costs associated to electricity import and export will improve the accuracy of economically optimal reserve margin calculation.

- Resource adequacy problem in this study and in the literature is defined and considered as an issue during peak load period. However, in presence of a very high share of variable RES in the market, the resource adequacy will be not only an issue during peak load period but also during medium load period. In other words, in presence of high share of RES, the optimal generation mix will be changed and the resource adequacy should be analyzed in all different load periods across the year. This ongoing change in generation portfolio will have both technical and financial effects on the resource adequacy. The next step of this study would be to assess the impact of optimal generation mix on the resource adequacy in presence of significant generation from variable RES.

- Storage facilities are going to play an essential role in future electricity markets. Electricity storage has a significant impact on ensuring resource adequacy in electricity markets. Specifically, storage systems would attract more interest in the German electricity market thanks to their ability to compensate the very low capacity credit of variable renewables. Therefore, any plan to increase the share of variable RES must be accompanied by similar supporting policies to improve the utilization of storage facilities. These support policies would result in a greater reduction in the capital cost of the latter and facilitate the integration of storage capacity into the electricity market. German energy-only market with sufficient storage capacity could ensure resource adequacy in lower reserve margin conditions with lower cost. That said, analyzing the impact of storage on the resource adequacy in the German electricity market would be an important area of future investigation.

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Annex C: Reliability Standard Methodology. 2013

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Curriculum Vitae

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Since 2013, Ph.D. student at Energy Economics Group, TU Vienna, Austria.

2009 - 2012, M.Sc. in Electrical Engineering at University of Tehran, Iran.

2005 - 2009, B.Sc. in Electrical Engineering at University of Tehran, Iran.

Honors and Awards

Student Paper Award in 33rd USAEE Energy Economics Conference, Pittsburgh, USA, 2015

Full Scholarship for a MSc program at University of Tehran, 2009-2012

Ranked 3rd among MSc students in Control Systems at University of Tehran, 2012

Ranked 138 among almost 400,000 participants in university entrance exam, Iran, 2005

Teaching Experiences

Game Theory (Spring 2011), Pattern Recognition (Fall 2011), Digital and Nonlinear Control Systems (Spring 2010), and Linear Control Systems (Fall 2009) at University of Tehran, Iran

Selected Publications

- H. Aghaie, 'The impact of intermittent renewables on the resource adequacy in electricity markets', IEEE Electrical Power and Energy Conference 2016, Ottawa, Canada.
- H. Aghaie, 'The impact of scarcity prices on resource adequacy in energy-only markets', 33rd USAEE/ IAEE Energy Economics Conference, Pittsburgh, USA, 2015.
- H. Aghaie, and R. Haas, 'Efficient Energy-Only Markets', 12th International Conference on the European Energy Market, Lisbon, Portugal, 2015.
- H. Aghaie, P. Palensky and R. Haas, 'Model-based Analysis of the Impact of Effective Competition on Supply Security in Energy Market', 11th International Conference on the European Energy Market, Krakow, Poland, 2014.
- H. Bosseti , S. Khan, H. Aghaie, and P. Palensky, 'Survey, illustrations and Limits of Game Theory for Cyber-Physical Energy Systems' at magazine- Automatisierungstechnik, 2014
- H. Aghaie , B. N. Araabi, and M. Nili 'Embedding Relevance Vector Machine in Fuzzy Inference System for Energy Consumption Forecasting' Lecture Notes in Computer Science, Volume 7664, 2012, pp. 202-209