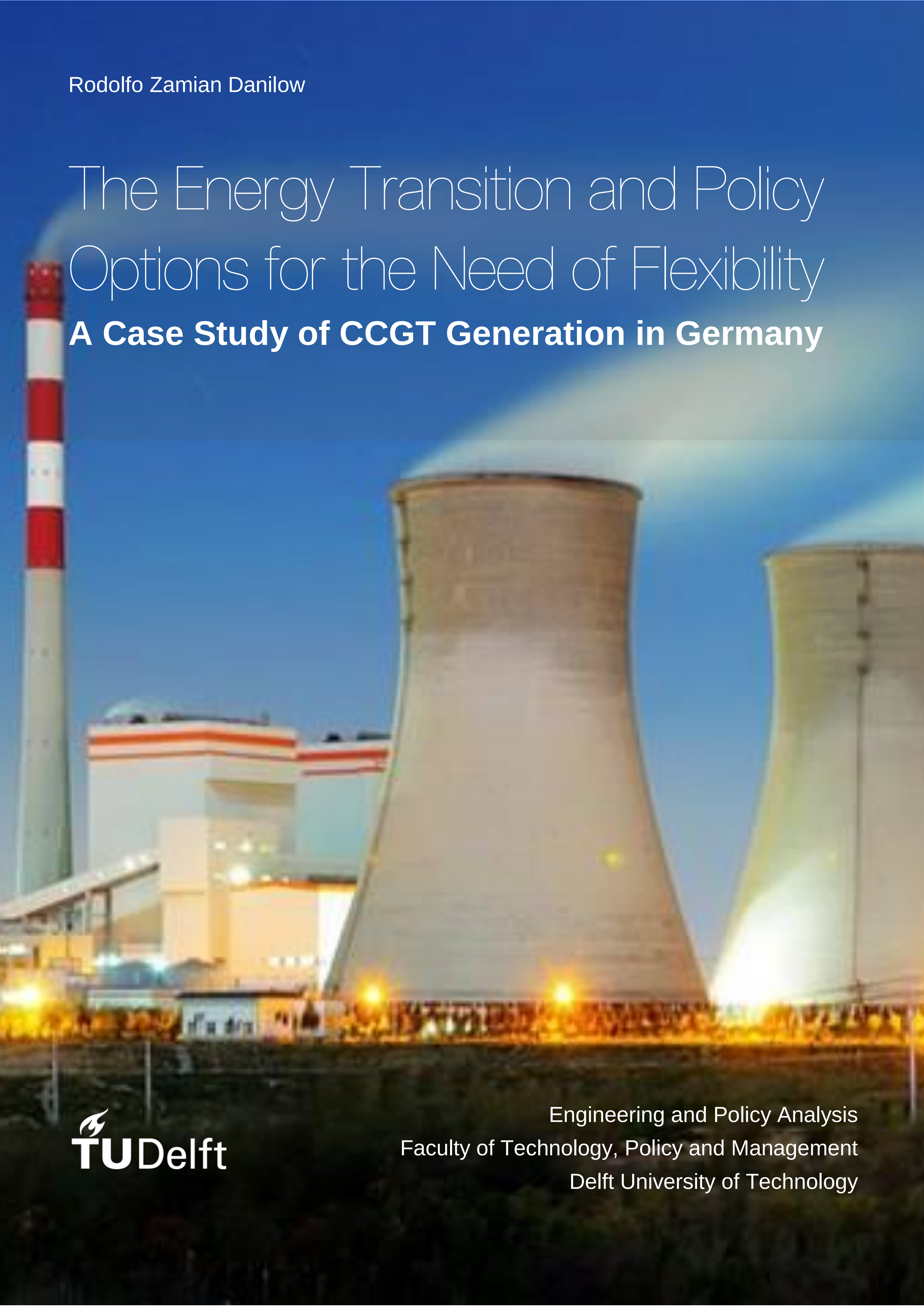
Rodolfo Zamian Danilow

The Energy Transition and Policy Options for the Need of Flexibility

A Case Study of CCGT Generation in Germany



Engineering and Policy Analysis
Faculty of Technology, Policy and Management
Delft University of Technology

The Energy Transition and Policy Options for the Need of Flexibility

A Case Study of CCGT Generation in Germany

Master thesis submitted to Delft University of Technology

in partial fulfilment of the requirements for the degree of

Master of Science

in Engineering and Policy Analysis

Faculty of Technology, Policy and Management

By

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Student number: 4576608

to be defended publicly on October 17, 2018.

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Preface

This thesis is the result of two years of study and research for my master's degree in Engineering and Policy Analysis (EPA). The topic choice was motivated by the lessons I have collected about energy policy, both from the classes in TU Delft and from my previous work experience in Brazil. I have had long interest in the sector and, more precisely, the conviction that the challenge of energy transition requires remarkably more effort than what exists today. As the EPA programme reinforced to me the advantages of multidisciplinary approach to solve problems, I attempted to combine my background on the market regulation of the natural gas sector and gas-fired power generation with the skills acquired on policy-making and economics.

This research is oriented for policy-makers of energy and power systems, as well as related fields, such as economic and environment policy. The research is also targeted for scientific researches interested in the social-technical aspects of power systems and the grand-challenge of climate change and energy transition.

I am very grateful for my family, friends and research committee, who provided me crucial support and knowledge to complete this task. I would like to thank my wife, who encouraged me to embark on the journey to take an MSc abroad and also supported me, emotionally and with the studies. My parents and my sister, who gave me so many opportunities that allowed me the freedom to positively choose my path. My new friends in the Netherlands, from all around the globe, that made home a bit closer. And my research committee that contributed with many lessons and support on this thesis. A special thanks to Enno, for motivating me and for his great deal of attention.

Rodolfo Zamian Danilow

Delft, October 2018

Executive Summary

National policies that seek to stimulate the energy transition require attention with the requirement for generation sources that can compensate for moments when wind and solar plants are not available. Electricity supply needs to adjust to demand in real-time, at least until energy storage becomes commercially viable, otherwise the energy security is compromised. Hence, the dilemma for energy policies is to continue to promote the expansion of renewables at the same time they secure the provision of flexible sources.

One well-known power source that can vary its output in a more flexible manner is natural gas-fired power-plants. More specifically, the combined-cycle gas turbine (CCGT) is a mature technology that presents low greenhouse gas emission and a high degree of efficiency. It can be turned on or off relatively rapidly to compensate for large or unexpected variations from wind and solar sources. It has been used for a long time in the power sector, however, now there is concern over its economic viability. The reason is that the rapid advance of wind and solar power generation reduces both the number of running hours for them and the electricity wholesale price. This is known as the merit order effect of renewables.

Germany is a frontrunner in renewables expansion. Recently, it enacted the Energy Market 2.0: while feed-in tariffs will continue to support wind and solar, it proposes a market design to accommodate the increasing intermittency. The underlying belief is that a competitive environment will allow market forces to provide the necessary flexibility in an economic efficient manner. Therefore, the German power sector makes an interesting case to investigate the effectiveness of an energy policy to attract adequate investment in CCGT generation in a scenario of growing presence of renewables.

That is to say that the success of the Energiewende (Germany`s energy transition and a major political objective) in this new policy framework depends on how the generation firms, as market actors, perceive the market conditions and investment incentives. One of the objectives of this research is to investigate the perception that these market actors will have on the competitiveness of CCGT, using generation costs as a criterion.

Another objective of this research is to examine the perception from the federal government on CCGT generation and if it is a socially efficient option for flexibility. The combustion of natural gas causes climate change and air pollution. Currently, they are unaccounted for. These external costs need to be considered in order for the energy policy to be social efficient.

To assess both perceptions, this research uses a tailored Levelized Cost of Energy (LCOE) calculation that evaluates investment attractiveness for a CCGT power-plant in the context of a high presence of renewables. The LCOE method considers all costs incurred by the investor throughout the power-plant’s lifetime, its expected generation output, and yields a single value result. So, it conveys the complexities of investment appraisal in a relatively simple manner. Although the LCOE method is internationally recognized as a benchmark, there is no prior research that applies it to investigate CCGT generation in the described scenario. For comparison purposes, energy storage is also investigated as it might become more economic efficient. Then, the external costs are examined and added to the LCOE results.

This research finds that CCGT generation firms in Germany will not have sufficient incentive, in terms of cost-competitiveness, to invest in new power-plants between 2020 and 2030.

Investments in this period have repercussion for the system until 2060. It is also found that CCGT generation is not a cost-effective option for flexibility from a societal perspective either. Energy storage is more cost-advantageous than CCGT, especially when external costs are considered. These conclusions are based on the findings described below.

The first set of results shows that the amount of energy that a CCGT plant is expected to generate in the future in Germany is indeed uncertain due to the increasing presence of RES. This is also referred to as the capacity factor, which is the percentage of the equivalent time in one year that the plant generates electricity at full capacity. The uncertainty range of the capacity factor is found to be fairly large, from 21% to 57%.

This research also finds that the levelized cost of CCGT is between 88 and 93 EUR/MWh (for a capacity factor of 39%). The results reflect the cost a generation firm perceives for a new plant entering operation in 2020, i.e. for which the investment decision is being made in 2018. The levelized cost for new plants to enter operation in 2025 and 2030 become gradually higher.

Sensitivity analysis shows LCOE ranges from 79 to 117 EUR/MWh using the capacity factor uncertainty range. Sensitivity analysis with other variables shows that fuel price is more relevant for the LCOE result than the capacity factor. The discount rate, and investment and emission costs are less relevant than the capacity factor.

In order to put these results in perspective, they are compared with electricity prices and with energy storage costs. Comparison between the LCOE and electricity wholesale prices shows that the costs incurred by generating firms are higher than prices they can obtain. The difference varies from 26 to 46 EUR/MWh, or 46% to 64%. Hence, revenues from the wholesale market alone does not provide sufficient incentive for investment.

Two energy storage options can provide flexibility in the same basis as CCGT and are technologically mature, namely compressed air and pumped hydro energy storage. They have levelized costs of 112 and 77 EUR/MWh, i.e. similar to CCGT. Conversely, one emerging energy storage option is the vanadium redox battery. Its current levelized cost is 206 EUR/MWh, but it is expected to decrease to 113 EUR/MWh in 2030 and become competitive.

Some important characteristics of the examined energy storage technologies are that compressed air and pumped hydro units are depend on appropriate sites to be constructed (e.g. underground cavern or an elevated natural lake), having limited expansion capacity. Vanadium battery is an evolutionary technology and, although it might become a competitive option for flexibility, it poses uncertain cost development.

The perception that the German federal government has on the situation is influenced by the external costs. The damage of climate change and air pollution imposed by CCGT generation are estimated to be 52 EUR/MWh. When these external costs are added to its LCOE, the cost perceived by the government to be between 115 and 155 EUR/MWh. This change represents an increase from 27% to 54% in relation to the generation cost perceived from a private firm. Hence, CCGT`s externalities cause it to be even less attractive and oversupplied.

External costs of storage are considerably lower. The cost comparison including externalities shows that the two mature energy storage technologies are more competitive than CCGT for new units in 2020, 2025 and 2030. Vanadium batteries competitiveness is further improved for new units in 2030, but still with significant uncertainty.

Therefore, CCGT plants are expected not to be attractive for generation actors under the German energy policy framework. Their levelized costs are similar to those of energy storage and higher than electricity prices. Moreover, the externalities cause it to be even less attractive. Vanadium batteries pose as a promising alternative for the system after 2030, but its uncertain cost development required public investment might be necessary to guarantee it effectively becomes competitive. Finally, policies to incentivize CCGT generation seem economic inefficient and are not advisable, as the construction of incentivized new CCGT plants during the next ten years would create long-term lock-ins.

Table of Contents

List of Figures

List of Tables

List of Graphs

List of Abbreviations

CAES – Compressed air energy storage;

CCGT – Combined-cycle gas turbine;

EEG – Erneuerbare-Energien-Gesetz, the German Renewable Energy Act;

EIA – U.S. Energy Information Administration;

ENS – Energistyrelsen, the Danish Energy Agency;

ES – Energy storage;

ESS – Energy storage system;

EU-ETS – European Union emission trading system;

EUR/MWh – Euro per megawatt-hour;

FIT – Feed-in tariff;

GHG – Greenhouse gases;

IEA – International Energy Agency;

IRENA – International Renewable Energy Agency;

LCOE – Levelized cost of energy;

LCOES – Levelized cost of energy storage;

MW – Megawatt;

MW_i – Megawatt installed;

MWh – Megawatt-hour;

PHS – Pumped hydro storage;

RES – Renewable energy sources (in this research, refers to wind and solar sources);

UBA – Umweltbundesamt, the German Federal Environmental Agency;

VRFB – Vanadium redox flow battery.

1. Introduction

1.1. Problem Definition

Climate change is an international grand challenge for which society requires knowledge to reduce greenhouse gas (GHG) emission while maintaining economic targets, including enhanced energy security (Reid et al., 2010). European Union (EU) member countries have the target to increase the share of renewable energy sources (RES) to 35% by 2020 and 60%-80% by 2050 (European Parliament & Council of the European Union, 2009).

The fast expansion of RES addresses the challenge of climate change, but it raises two paradoxical issues. On the one hand, wind and solar generation is intermittent, or inflexible, and require conventional sources to account for periods of low wind speed and sunlight radiation, at least until energy storage is economic viable. On the other hand, they can compromise the economic profitability of conventional plants due to the merit order effect of renewables: both the electricity wholesale price and the number of hours that other sources can generate are reduced. Therefore, a large share of RES can lead to inadequate investment on complementary flexible sources and compromise energy security (Blazquez, Fuentes-Bracamontes, Bollino, & Nezamuddin, 2018; Borenstein, 2012; Praktiknjo & Erdmann, 2016). Considering that security of supply is one of the goals for the electricity sector regulation and considering the new paradigm for the EU power systems under fast increasing presence of RES, it is necessary to investigate policy options that can provide the necessary flexibility.

Among conventional generation technologies, the combined-cycle natural gas turbine[1] (CCGT) power-plant is a viable option to provide the required flexibility. It is a mature technology and presents “relatively low capital cost, short construction time, high degree of efficiency, and operational flexibility” (IEA & NEA, 2015, p. 38). It also has relatively low GHG emissions compared to other fossil fuel-based sources (Laloux & Rivier, 2013). So, this technology presents itself as a well-known and broadly used investment option that can compensate for wind and solar intermittency.

Germany is a frontrunner in RES expansion and is politically engaged with its energy transition, the Energiewende. It has recently passed a new energy act, the Energy Market 2.0, which maintained the direct financial incentives for renewables through feed-in tariffs in order to increase their share up to 80% by 2050. Meanwhile, it has not adopted any specific instrument to incentivize conventional sources, such as a capacity mechanism, although generation firms argued that it is necessary for their profitability and to maintain investment. The new policy framework relies on the belief that a competitive environment will offer the necessary investment signals and that market forces will select the most economic efficient technologies (BMWi, 2015; Debor, 2018).

[1]CCGT is a power generation technology that uses natural gas as fuel and takes advantage of the process heat to improve its efficiency. It can also be named, in a simplified manner, gas-fired plant.

1.2. Project Scope

The success of policies oriented to promote the energy transition depends on adequate investment in flexible sources, i.e. sources that can provide energy when wind and solar plants are unavailable. Under this prism, the German new policy framework makes an interesting case for the examination of CCGT generation economic attractiveness under a lower number of running hours due to increasing RES presence. Therefore, this research tries to answer the question of whether CCGT generation is a good option in terms of costs for the need of flexibility of the German power system during the energy transition to guarantee energy security. For such, this research investigates how private firms perceive gas-fired generation as an investment option and how the government perceives it as an attractive option of flexibility. The criterion used is generation costs, including external costs.

To assess this perception, the Levelized Cost of Energy (LCOE) method is internationally recognized as a benchmark for assessing the economic viability of different generation technologies. It considers all costs incurred by the investor throughout a power-plant lifetime, its expected generation output, and yields a single value result. So, it conveys the complexities of investment appraisal in a relatively simple manner and allows the comparison of multiple technologies (Konstantin & Konstantin, 2018a; Partridge, 2018).

Although the method is broadly used, there is no prior research that applies it to investigate CCGT generation competitiveness in a scenario of growing shares of RES. The examined studies have various goals for calculating LCOE and, therefore, the underlying financial and economic assumptions are often not in line with the scenario of the problem in hand. For instance, the International Energy Agency (IEA) reports the same capacity factor of 85% for CCGT, coal and nuclear generation, using the assumption that they all serve the baseload in order to compare them on the same basis of energy output. Likewise, the Danish Energy Agency (ENS) uses a discount rate of 4%, which corresponds with its objective to investigate the social costs of electricity generation. Inasmuch as the method is sensitive to the input variable assumptions, the existing LCOE results are not pertinent for the present policy analysis.

One of the objectives of this study is to assess how a CCGT generation firm perceives the cost-competitiveness of gas-fired technologies and how it is affected by diminished number of running hours. This indicates they propensity to continue investing in the technology within Germany`s new energy policy framework. Hence, this research uses a tailored LCOE calculation that depicts investment attractiveness for a CCGT power-plant under the circumstance of high share of RES. Several studies are examined to scrutinize their assumptions and to compile a set of input variables plausible with the proposed scenario. Energy storage technologies that can provide flexibility on the same basis as a CCGT plant are also investigated for comparison purposes.

Another objective of this research is to evaluate the cost advantage of CCGT generation as a source of flexibility for the German power system when all external costs are internalized. This provides insights on Germany`s Electricity Market 2.0 and its success in achieving social efficiency. The difference from the private and social perspective lies on the externalities of climate change and air pollution caused by GHG and air pollutant emission. CCGT external costs are not taken into account by private firms, what causes its output level to be socially inefficient (Ventosa, Linares, & Pérez-Arriaga, 2013). For instance, the CO_2 price on the EU Emission Trading System (ETS-EU) is considered too low and too volatile, so GHG emission imposes damage on society that is not fully accounted for (ENS, 2015; Zweifel, Praktiknjo, & Erdmann, 2017). Hence, this research adds the relevant external costs to the levelized generation costs in order to examine CCGT cost-competitiveness from a societal perspective.

To achieve the research objectives, it is first necessary to examine what is the expected capacity factor for CCGT generation in Germany during the energy transition. The existing literature presents concern over the economic viability of gas-fired plants due to the fact that increasing presence of RES reduces their output level (Erdmann, 2017; Traber & Kemfert, 2011). However, specialists do not converge on the forecast for this variable. Hence, this research analyses the literature in order to compile the existing propositions and to suggest a range of values that is adequate with the expected scenario for German power sector.

The remaining of this thesis is organized as follows. Section 2 presents a literature review, with core concepts relevant for the issue, the background of Germany's power sector and an actor analysis. This review leads to the knowledge gap identified and the research questions. Section 3 introduces the research approach and introduces the methods and required data. Section 4 presents the data collection. Section 5 lays out the obtained results and a discussion. Conclusions are then presented in Section 0. Finally, Section 7 offers some reflections and limitations of this work, as well as suggestions for future research.

2. Literature Review and Background

This section presents the literature review on RES integration into power systems and its economic implications. The current energy policy instruments have been broadly studied since market liberalization, but the literature indicates they might need adjustment to the new paradigm of large share of renewables, intermittency and reduced running hours for conventional sources.

This section is divided in four parts. First, concepts related to the power sector and relevant to understand the problem are described, followed by an overview of the German policy framework, including an actor analysis. Then, a summary is introduced about the existing research on the relation between energy policy and the insertion of renewables. Finally, the research question is posed.

2.1. Core Concepts

2.1.1. Flexible and Inflexible Power Generation

A power-plant’s flexibility corresponds to the ability of the operator to vary its output level within an operational time slot (e.g. an hour, a quarter of an hour). The possibility to control the generation allows electricity production to follow the predicted and the real-time fluctuation of demand, and thus the plant is called flexible or dispatchable. This is the case of natural gas, coal, hydroelectric, and biomass plants (Borenstein, 2012; Zweifel et al., 2017). Nuclear plants are less flexible, as they have more operational restrictions that diminish its temporal control (Laloux & Rivier, 2013).

Regarding CCGT generation and its physical construction, it is worth noting that boilers not in operation require a period of time to warm-up and start generating – this is called the ramp-up of a plant. However, operation can be anticipated to a state in which it can start generating without the delay of the ramp-up. Therefore, CCGT can adjust its output to follow the demand curve, resulting in a high level of operational flexibility (Laloux & Rivier, 2013).

Conversely, Borenstein (2012, p. 74) state that inflexible or intermittent sources are “those that vary significantly due to exogenous factors”. This is the case of wind and solar power-plants, referred as RES in this research, since their generation is subject to weather conditions. So, the operator does not have the ability to choose the output level according to the demand curve and its fluctuations. Although it cannot be chosen when to produce electricity, the operator does have the option to shut-down the plant or impose an upper limit to the generation level.

2.1.2. Energy Policy Goals

Zweifel et al. (2017) define the magical triangle of energy policy goals: security of supply, economic competitiveness and environment protection. Security of supply is the goal to guarantee availability of energy to meet demand, including the notion of supply-demand balance and of real-time demand adequacy. Competitiveness relates to the energy price, that comprises an investment signal for generation actors as well as the notion of affordability for energy consumers. Environment protection refers to socially acceptable sustainable development of the system, including the reduction of GHG emissions.

Energy policies are implemented when the result from the market alone and its freely acting, self-interested participants, is not Pareto-optimum. Policies are implemented to correct market failures and help increase social efficiency (Batlle & Ocaña, 2013; Zweifel et al., 2017).

2.1.3. Support Schemes for RES

Governments may choose to incentivize the expansion of RES share on their power matrix for varied objectives, such as environmental protection, increase of energy security and industrial development. The policy instruments to put in place these incentives are called support schemes for renewables, or simply support schemes. They are categorized as price instruments, e.g. feed-in tariffs (FIT) or feed-in premiums (FIP), and quantity instruments, e.g. renewables portfolio standard (Linares, Batlle, & Pérez-Arriaga, 2013).

The FIT support scheme secures a pre-determined price for the energy a RES generator produces, regardless of the wholesale market price. So, the revenue from the market, based on the closing price and quantity sold, is supplemented: the difference between the closing price and the pre-determined one is covered by the policy. So, the investor is not subject to the market price variation and has better conditions to recover the investment in the long-term. The FIP scheme is similar to the FIT, as it increases the revenue of RES generators. The scheme determines a fixed premium that is to be paid on top of the closing market price (Linares et al., 2013; Pérez-Arriaga, 2009).

The RPS is also named renewables obligation. In this support scheme, suppliers, consumers, and even generators are imposed a minimum quota of their portfolio to be composed of RES (in this case, not necessarily only wind and solar). Although there is no direct financial support, a market for RES is effectively created.

2.1.4. Merit Order Effect of RES

The merit order effect of RES refers to the impacts that renewables have on the operation of other power generation technologies and on the wholesale price of electricity. It derives from the concept of merit order, which will be introduced first.

The merit order is the ranking of all available power supply for the day-ahead market according to their price bid. The concept also includes the notion that the offers with the lowest prices have preference on the dispatch. In competitive markets, the bids correspond closely to generation marginal cost (Praktiknjo & Erdmann, 2016). Figure 1 illustrates the merit order in Germany, presenting all bids organized and forming a schedule from lowest to highest prices[2].

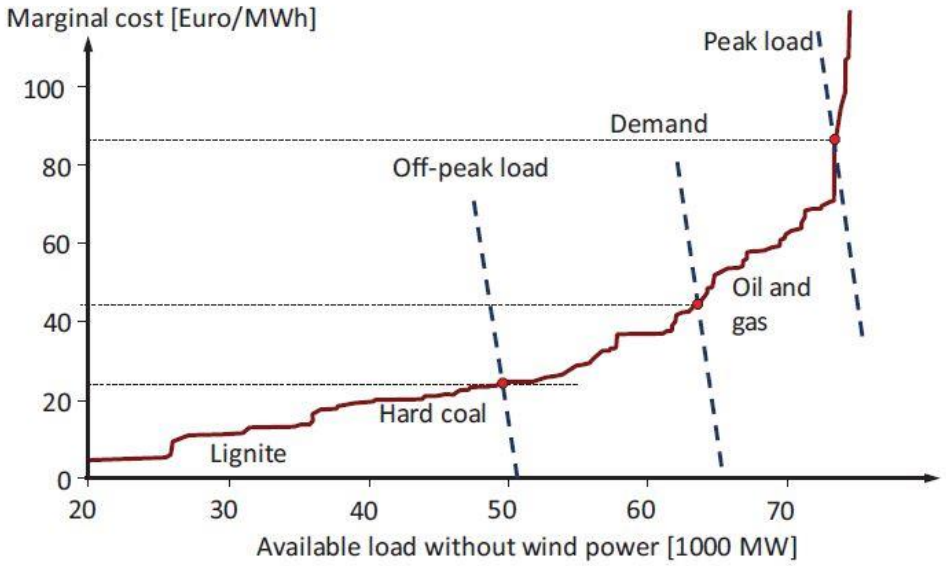

Figure 1. Merit order of German power plants without wind power (Erdmann, 2017, p. 7).

Concerning the merit order effect of RES, the causes of the impacts are that i) wind and solar generation stand at the beginning (most left position) of the merit order schedule, as they present very low marginal costs, and ii) they are intermittent sources. This implies the market experiences two distinct situations when RES are available and not available, as described below (Erdmann, 2017; Praktiknjo & Erdmann, 2016; Sensfuß, Ragwitz, & Genoese, 2008).

On one hand, when RES are physically available, they cause a horizontal shift to the right of the merit order schedule, and lead conventional generation to be less used, considering demand remains the same (Erdmann, 2017; Linares et al., 2013). RES availability also reduces the wholesale price, as the shifted supply curve makes the market clear on a cheaper power-plant. On the other hand, when RES are not available, the merit order schedule shifts left again, increasing the wholesale price (Praktiknjo & Erdmann, 2016). The larger the RES share, the more acute the effect is.

In a system with large presence of renewables, a number of technologies can be used to deal with the increased intermittency, including CCGT generation. However, the merit order effect of RES compromises the capacity of conventional generators to recover their investment (Erdmann, 2017).

2.1.5. Capacity Mechanisms

de Vries, Correljé, and Knops (2017, p. 45) state that there are concerns whether the market forces alone are capable of securing an adequate installed generation capacity, i.e. “if it can be expected to meet demand under all reasonable conditions, considering normal

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[2] The bid is an offer to sell energy, usually for the next day, composed of price and quantity.

outage rates”. This debate addresses fundamental electricity market failures and it existed previous to the large presence of RES.

One key characteristic of energy-only electricity markets[3] is that the provision of installed capacity increases system reliability in the form of a public good. System reliability is increased because more generation capacity reduces the occurrence chances of both demand curtailment and elevated scarcity prices. These benefits affect all consumers due to the network nature of power systems. Also, generation firms cannot charge consumers for the service, or that the latter can contract generator reliability. Hence, the provision of installed capacity is non-excludable and non-rival, making it is a public good. As a positive externality, it will be under-provided in competitive markets. Capacity mechanisms are energy policy instruments aimed at correcting this failure. Capacity market and strategic reserve are the main examples (de Vries et al., 2017).

Capacity market is a capacity-based instrument, where suppliers and consumers are required to purchase capacity credits from generators. This creates a revenue stream for generation firms, supporting the recovery of their fixed costs, and ultimately incentivizing investment. As it creates a market for capacity in addition of the market for electricity, the system is no longer considered an energy-only market (de Vries et al., 2017).

Strategic reserve, on the other hand, is a price-based mechanism, in which the system operator acquires or leases power-plants to be used in emergency cases (e.g. during large capacities outages and unforeseen demand spikes). It creates an additional spare capacity in the system and effectively caps the price. As investment incentive continues to be based on spike prices (capped on a high level) the wholesale arrangement becomes a modified energy-only market (de Vries et al., 2017).

2.1.6. External Costs - Pigouvian Tax

One method for internalization of external costs is the Pigouvian tax. The principle is that a tax on the activity that generates the externality creates an incentive for the reduction of its output towards the socially optimum level. The tax is charged per unit produced and set exactly to the externality`s marginal value, i.e. the marginal damage. Conversely, the method can also be used for positive externalities, using subsidies to increase the produced quantity (Gruber, 2012; Ison, Peake, & Wall, 2002).

Figure 2 illustrates the use of a corrective tax to cause the product price to reflect the social marginal cost. In the figure, without intervention, the market equilibrium occurs at point A, where the lower price P_1 does not include the marginal external cost (MD, for marginal damage) and leads to a consumption level of Q_1, implying an overconsumption of $Q_1 – Q_2$. Firms have a private marginal cost of PMC_1 and have no legal obligations towards the externality. Thus, taxing the product by the amount of the marginal damage (MD) makes the firms` new marginal cost (PMC_2) to be equal to the social marginal cost (SMC). The resulting social equilibrium at point B (where social marginal benefits and costs are equal)

[3] A liberalized electricity market without a capacity mechanism is an energy-only market. This means the it provides essentially one revenue stream for generation firms, which is from the energy they effectively sell on the day-ahead and intra-day markets and over-the-counter contracts. Therefore, the spot-price and expectation on scarcity-prices are the main economic investment signals.

decreases consumption to Q_2, ending overconsumption, and increases price to P_2, reflecting the efficiently internalized externality (Gruber, 2012).

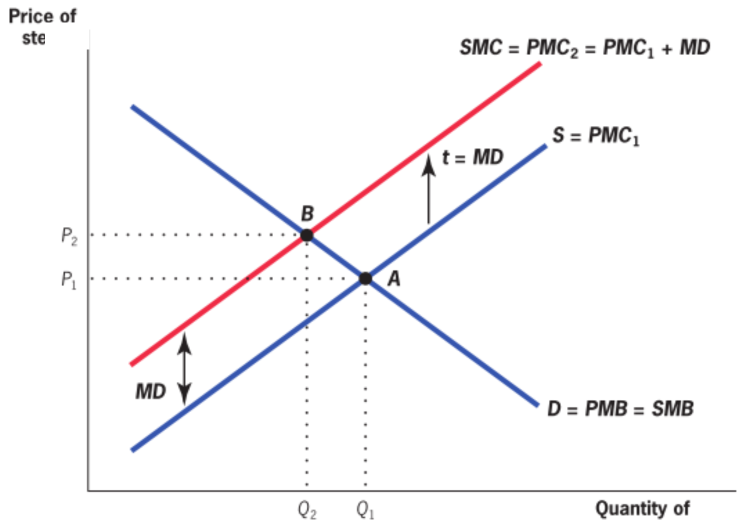


Figure 2. Use of Pigouvian tax to reduce output level from Q_1 to the social optimum Q_2. Adapted from Gruber (2012, p. 135).

It is interesting to note that the Pigouvian tax has two effects over the market. One is that it may lead to actual reduction of the output and, consequently, of the incidence of the external effect. The other effect is that the remaining quantity is priced by the tax (price P2 in Figure 2), meaning that remaining consumers are paying for the external cost. For this reason, it is considered a more cost-effective environmental policy instrument, together with tradable allowance systems (Goulder & Parry, 2008).

The concept behind Pigouvian tax is interesting for this research. It implies that an externality can be measured and monetized into one value, per unit of output. Hence, the externality can be contemplated in a policy analysis in a relatively simple manner.

2.1.7. EU Emission Trade System (EU-ETS)

The EU-ETS has the purpose to combat climate change by internalizing into electricity prices the costs incurred to society due to GHG emission. However, it is considered not to achieve its goal because the emission allowances prices have been too low and too volatile since its implementation (ENS, 2015; Zweifel et al., 2017). So, the allowance price internalizes only partly the climate change costs of electricity generation.

2.1.8. Energy Storage

An energy storage system (ESS) can take in energy and release it on a later moment. For the power sector, the ESS is charged with electrical energy, which is usually converted to another type of energy (e.g., pumped storage, chemical). When required, the energy is transformed back to the electrical form and discharged. These steps are the charging/loading, saving, and discharging/unloading phases, respectively. The period of time that the ESS can store energy depends on the technology and its construction, and can vary from seconds to years (BVES, n.d.). Stored energy can be expressed in kWh or MWh, and the unit's power capacity in kW or MW.

ESS can provide several types of service to power systems, e.g. energy shifting, peak shaving, frequency control, increased power quality, island grid. Storage technologies are more appropriate for each service depending on their power capacity and discharge time (ENS, 2012; IRENA, 2017). Figure 3 illustrates which energy storage (ES) technologies are appropriate for each service nature, considering their state-of-the-art. Future technological developments may amplify their scope of work.

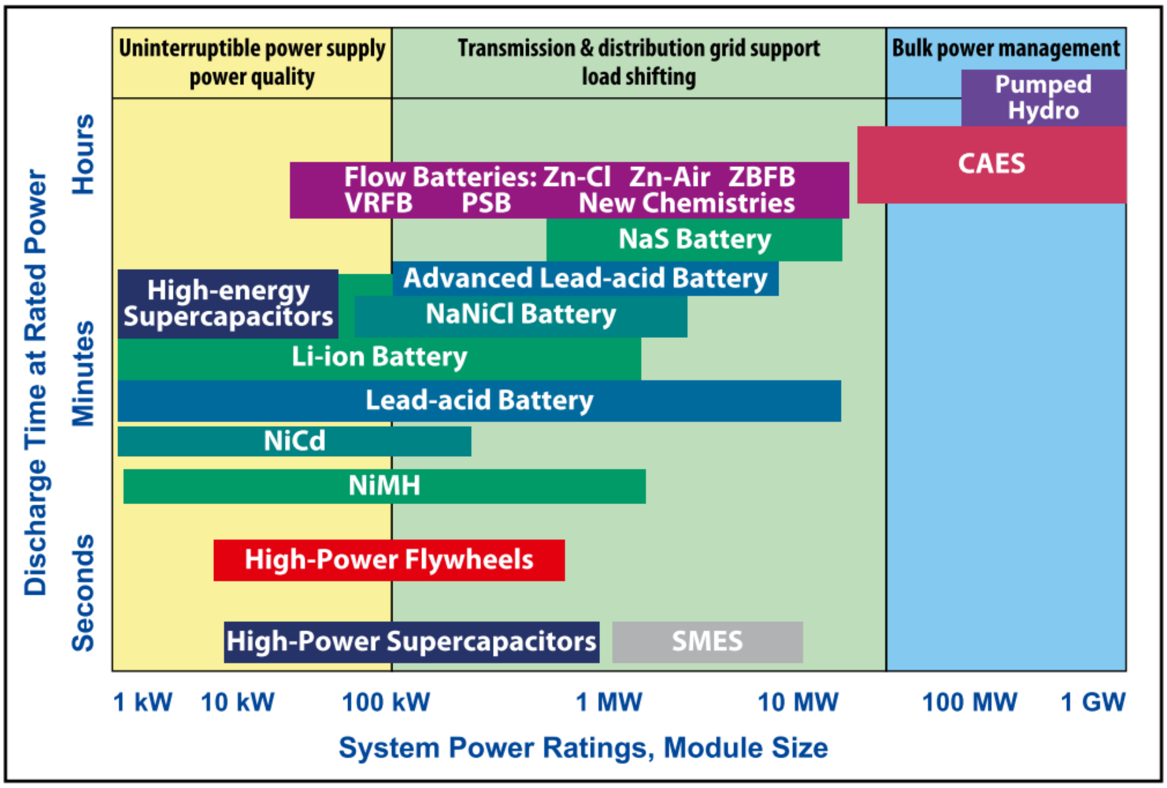


Figure 3. Services provided by ES type according to their current discharge time and power rating, according to IRENA (2017, p. 41).

The definition of long-term storage, or seasonal storage, is given by IRENA (2017, p. 43) as: "Stores energy over periods of weeks or months. Long-term storage is typically achieved using power-to-gas converters in combination with gas storage systems or large mechanical storage systems such as pumped hydro storage or CAES. Additionally, redox flow batteries and NaS batteries may be able to deliver reasonable weekly storage as their energy-related investment cost declines".

The service necessary to provide system flexibility in order to compensate for RES inflexibility is the bulk power management, or energy shifting. This means an energy storage system to be designed to provide electricity for the period scale of days to months, at a power rating comparable to large-scale power-plants, i.e. larger than 100 MW. Compressed Air Energy Storage (CAES) and Pumped Hydro Storage (PHS) are currently mature technologies that can provide bulk energy management. The Vanadium Redox Flow Battery (VRFB) technology is expected to develop and its costs to reduce over the next ten years, making it a suitable option to provide this service in the future (IRENA, 2017).

A CAES unit stores energy in the potential elastic form, by storing compressed air in a reservoir. Electrical energy is used to pump air into a cavern, such as old natural salt deposits or depleted gas fields - which is the charging process of CAES and can be performed during excess of RES generation. During moments of high demand or low RES generation, the stored air is released and heated to run a gas-fired turbine generator (ENS, 2012; IRENA, 2017). Little research was found in the literature regarding the potential for energy storage using CAES. Klumpp (2015) proposes a technical potential of 370 GWh, but presents no discussion on the attainability of this potential.

PHS stores energy in the gravitational potential form, by storing water in an upper reservoir with different altitude from a lower reservoir. Electrical energy is used to pump water from the lower to the upper level, which is the charging process of PHS and can be performed during excess of RES generation. Conversely, the accumulated water is released from the upper reservoir to rotate the turbine-generator unit, and so as to generate electricity during periods of low wind and sunlight (ENS, 2012; IRENA, 2017). The estimative of PHS energy potential in Germany is 45 GWh, a slightly more than the existing 38 GWh (eStorage, 2015).

VRFB stores energy in chemical form, by storing vanadium in different oxidation states in electrolyte tanks separated by an ion-selective membrane. Electrical current charges the battery by changing the electric charge of its elements, the redox process, which can be performed during excess of RES generation. The chemical process can be reversed to generate electric current during moments of low RES generation. The VRFB technology can have its power and energy characteristics scaled independently, and so it is also suitable for other services, e.g. grid frequency regulation and community/residential storage (ENS, 2012; IRENA, 2017).

2.2. Energy Policy in Germany

2.2.1. The Energiewende and the Electricity Market 2.0

The Energiewende is Germany’s energy transition, a socio-technical transformation process of the national energy sector to reduce the use of fossil fuels and GHG emissions. The process started in the nineties and gradually increased in relevance to become one of the main political goals of the current government. One of the main focus is to increase the generation share of RES in the power, heating system, and transportation systems, so as to replace coal, oil and natural gas combustion. Energy efficiency and reduction of demand are also considered (Debor, 2018). Joas, Pahle, Flachsland, and Joas (2016) argue a different perspective, that the Government’s interests with the Energiewende have not been clearly defined, and that the actors involved perceive several goals, such as security of supply, conservation of exhaustible resources and technological run.

There is especial focus on the electricity sector and promotion of RES. The official targets are to supply 50% of the electricity demand with RES by 2030, and 80% by 2050. One of the main instruments in place to achieve these targets is the German Renewable Energy Act (EEG, which stands for Erneuerbare-Energien-Gesetz). It was first published in 2000 to create incentives for renewable generation technologies. A support scheme of feed-in tariffs and preferential dispatch was enacted to bolster competitiveness. The policy has been adapted over time, and amendments were made in 2014 to provide the federal government with more control over the quantity of new plants to receive the benefit. A tendering model and limitation of RES annual increases are expected to curb the surcharge cost for consumers and ease the technical challenges to integrate intermittent renewables (Debor, 2018).

More recently, the government passed a new act for the power sector, called Electricity Market 2.0. Its publication addressed the continuity of the Energiewende and the need for complementary flexibility imposed by intermittent sources. In this act, one relevant policy option was to deny the implementation of a capacity mechanism, which was argued by conventional generators as necessary for their competitiveness and to maintain national security of supply. So, the German market continues to be an energy-only market. The Government’s argument is that the goal of the Energy Market 2.0 is to promote a competitive environment, so that market forces can provide the necessary flexibility in an efficient manner. Also, it was argued that a capacity mechanism is expansive and continues with the old ways of the market, which would be a contradiction with energy transitions goals. Therefore, the Electricity Market 2.0 relates strongly to the development of the Energiewende in the power sector, as it addresses the continuity of the RES market share expansion and the need for complementary flexibility (Amelang & Appunn, 2016; BMWi, 2015; Strunz, Gawel, & Lehmann, 2016).

2.2.2. Multi-Actor System Analysis

The problem introduced of increasing need of flexibility involves multiple actors from the German power sector. Hence, a multi-actor analysis is performed in order to achieve an encompassing understanding of the situation and the inter-dependence among the involved parties. Actor analysis is of great importance when one actor alone does not have sufficient means to solve the problem in hand. In the present case, the federal government adopted a policy to incentivize actors to invest in flexible sources, but ultimately it is the generation firms that will make the decision to do so. So, awareness of the interests, objectives, and means of each actor that are involved and impacted by the policy instruments under investigation is necessary to assess future behaviour (Enserink et al., 2010).

This section presents the first step of the analysis, which is to examine the literature on the relation that actors have with the general transformation process of the German power system. A following step is to use this examination to contextualize the particular situation of CCGT generation, i.e. a backdrop against which to discuss and interpret the quantitative results of cost-competitiveness. The multi-actor system analysis is performed following a simplification of the framework proposed by Enserink et al. (2010). Five academic articles were reviewed. Table 1 presents the six selected actors and their position and perception on the Energiewende. The actors are the German national Government, more precisely the Ministry of Economic Affairs and Energy, CCGT generation firms, coal generation firms, RES generation firms, energy intensive industries and households on their double-role of energy consumers and citizens. A discussion is then presented on the most relevant points.

Table 1.Literature review of selected actors' interests, goals, resources and perception.

	Interests	Goals within the Energiewende	Resources	Perception of the Energiewende
German Government, represented by the Ministry of Economic Affairs and Energy	Prevention of global climate change[1,2] (ideological motivation[1]). Maintenance of the current level of supply.[2] Low electricity costs for society.[2] Electoral success (self-interest motivation).[1]	Share of RES in the power sector of 50% in 2030 and 80% in 2050.[5] Technology and market leadership in RES.[2] Address the interests of the voters as well as satisfy industry interest groups.[1]	FIT programmes.[1] Give grid access priority for RES.[1] Phase-out specific technologies, e.g. nuclear and coal.[4] Welfare redistribution among stakeholders.[1]	Decision-making routines favour RES over conventional electricity.[1] Set of RES targets is balanced between the push for electoral gain, due to large popular approval, and the need for prudence, due to economic and technical aspects. Ambitious targets are set for the long-term.[4]
CCGT Generation Firms	Profit maximization.[3]	Implementation of a capacity mechanism.[4,5] Defend their market share against new RES producers.[1]	Lobbying.[1,3] Judicial contest against RES.[1] Influence public opinion on negative consequences from RES and support schemes.[1]	Neoclassical economic view that only emissions trading intervention is justified to account for externalities.[1] Large RES presence compromises profitability.[1] Threaten to security of supply[1], higher chances of blackouts, price increase and, thus, German economy weakening, and reduced available income to households.[4] FIT scheme is incompatible with future EU market design.[4] In favour of coal phase-out.[6]

Coal Generation Firms	Profit maximization.[3]	Implementation of a capacity mechanism.[4,5] Defend their market share against new RES producers.[1]	Lobbying.[1,3] Judicial contest against RES[1]. Influence public opinion on negative consequences from RES and support schemes.[1]	Neoclassical economic view that only emissions trading intervention is justified to account for externalities.[1] Large RES presence compromises their profitability.[1] Threaten to security of supply[1], higher chances of blackouts, price increase and, thus, German economy weakening, and reduced available income to households.[4] Discourse that FIT scheme is incompatible with future EU market design.[4]
RES Generation Firms	Profit maximization[3].	Raise rate of FIT.[1,3] Avoid frequent changes of the EEG[3]. Promotion of flexibility sources to allow of market share expansion.[5]	Lobbying.[1,3] “Claim that any weakening of RES policies would endanger green jobs and threaten the overall reputation of Germany as a technological frontrunner and nation of engineers”.[1,5] Political leverage due to large popular approval of RES[4]. Frame self-interest claims under the common good of Energiewende[1].	In favour of the adopted targets for RES generation.[5] FIT benefits should increase.[4] Opposed to capacity mechanism reform.[5]

Energy Intensive Industries	Profit maximization[3].	Prevent RES surcharges.[1]	Lobbying.[1,3] Convey the idea that industry segments “which are exposed to highly competitive international markets should be allowed to pay reduced RES-levies”.[1]	Benefits from the combination of reduced electricity spot prices, due to the merit order effect, while largely exempted from surcharges.[1,4]
Households, as energy consumers and citizens	Personal welfare maximization. More precisely, low energy costs and climate protection.[1] Ideological motivations.[1]	Produce distributed renewable energy (prosumers).[1] Prevent RES surcharges.[1,5]	Vote “in order to maximize their expected personal gain”.[1]	“Broad popular consent” to energy transition[1]. Wind and solar approval of 90% and large belief the transition is too slow.[4]

1. According to Strunz et al. (2016).
2. According to Joas et al. (2016).
3. According to Sühlsen and Hisschemöller (2014).
4. According to Fischer, Hake, Kuckshinrichs, Schröder, and Venghaus (2016).
5. According to Debor (2018).
6. Assumption of this research.

It is possible to observe that the policy arena is characterized by several and conflicting interests and goals. The selection of actors is based on the debate proposed by the reviewed articles. The literature perceives the involved firms in niches. Most of the RES installed capacity is owned by new players, while natural gas and coal plants remain with the incumbent companies. Energy users are mainly organized by the energy intensive industries. The national government, observed here as the Ministry of Economic Affairs and Energy, develops the energy policy by managing the diverging interests and accruing electoral support. Households are not well organized to actively bargain with other actors, but influence the system by voting according to their preferences and ideological motivations. In turn, all actors attempt to influence popular opinion in their favour.

The government does not make explicit and clear its interests with the Energiewende. This leaves market participants to interpret and infer them, causing there to be multiple perceptions of what are the interests. This fact contributes to the success of the Energiewende, as it opens space for negotiation of actors with the government and influence on public opinion.

Policy-makers, representing the national government, seek to balance the multiple conflicting interests of other actors by distributing welfare among them. In this way, they pursue to maximize electoral campaigns support and outcome. Specifically, regarding households on their role of citizens, there is a positive causal relation from the elevated public support for the energy transition towards the fact that individual politicians push to accelerate the speed of the transition with more ambitious targets. The potential goal conflict of households, i.e. the trade-off between reduced electricity bills and environment protection, is not an issue in this arena since the latter goal is more predominant.

The literature suggests that generation investing firms seek to increase their economic welfare outcome through lobbying, either as a collective, using class representation associations, or as individuals, by maintaining direct and close relation with policy-makers.

The CCGT and coal generation firms openly act to curb the RES expansion. Judicial contestation has been used, as well as attempts to influence public opinion on the risk to security of supply and household income reduction that RES bring. Additionally, lobbying efforts were made to implement a capacity mechanism, so as to reduce their revenue uncertainty. Although it was not found in the literature, it is plausible to assume that CCGT generation firms are favourable to a phase-out of coal generation, as it would be expected to increase the capacity factor of gas-fired plants.

The RES firms take advantage of the Energiewende popular approval to bargain for higher FIT. They frame their discourse under the idea that changes on support schemes are threats to green jobs and to Germany in the technological run. They pose their vested interests closely to citizens ideological motivations.

The energy intensive industries have a relatively comfortable position. They are largely exempted from the surcharges that finance the RES support schemes, so they do not incur in extra costs due to the energy transition. Moreover, they are benefited by the reduction of electricity wholesale prices caused by the high share of RES. Among consumers, they are the most well organized to influence the policy-making. Their lobbying efforts are precisely to prevent incidence of the surcharges, and it is possible to affirm they have succeeded so far.

2.3. Existing Research

2.3.1. Integration of RES and Conventional Generation

The existing literature investigates the impacts of RES on energy markets, on conventional generation, and on renewable generation itself. There is convergence among the reviewed authors on the concern that current energy policies will not promote the integration of large share of RES properly and, consequently, a sustainable energy transition.

Blazquez et al. (2018), Erdmann (2017), and Bushnell (2011) state that current energy policies are inadequate in face of the new paradigm of intermittency. Blazquez et al. (2018) define the term “renewable energy policy paradox” to describe that the large presence of RES in a liberalized market lowers the wholesale price to an extent to cause a negative effect on its own further expansion. The fundamental reasons are that RES do not satisfy the premises of dispatchability and positive marginal costs. From the market side perspective, RES have a levelized cost of energy (LCOE) significantly higher than their near-zero marginal cost, creating a discrepancy between system cost and wholesale price. From the policy side perspective, public support mechanisms become less effective or more expensive with more installed RES.

Similarly, Erdmann (2017) researches the economics of the alternatives that integrate RES and conventional generation and finds that there are inevitable costs to do so. One of the implications of a high-level of intermittency is that technologies that correct it depend on the number of running hours. The authors suggest that government should allow the market forces to select solutions through fair competition among the technologies. Hence, the government role is to implement energy policies that create such competitive environment.

The influence of RES on the economic scenario for conventional generation against the backdrop of combined market liberalization and energy transition is examined by Bushnell (2011). Large presence of RES and the incentive policies raise concern over cost and intermittency. Using modelling techniques for a case study of the US, he finds that flexible generation investment shifts towards less capital-intensive plants, that the need for thermal capacity is reduced only modestly due to a larger presence of RES, and that price becomes equally driven by demand changes and wind availability.

Sensfuß et al. (2008) and Praktiknjo and Erdmann (2016) analyse quantitatively the merit order effect of renewables and find significant impact on energy prices. The former research uses agent-based simulation and cost-benefit analysis for the previous five years of market operation in Germany. Sensitivity analysis indicates that increase of RES generation and fuel prices were the main drivers of the increase of the merit order effect. Alternatively, the latter research uses an econometric approach to quantify the merit order effect for one year of operation and its implications for conventional generators. The estimated effect is considered to make investment on conventional generation no longer economically viable. In the long-run, security of supply is impacted.

Finally, Partridge (2018) proposes that cost comparison and clear understanding of its uncertainties are key inputs for energy policy discussion. Yet, there is divergence on cost estimative of wind power and the present data have questionable validity. The components that cause the most problems for cost estimation are cost of capital and fuel. The study also estimates LCOE for wind energy in the US, Denmark and India. CCGT and coal costs are also computed to allow for comparison, and sensitivity analysis is performed for capital and fuel costs. The study does not consider external costs.

2.3.2. Generation Costs

Studies were found to investigate a specific RES technology and its choice of equipment or other economic factors. Furthermore, a series of studies estimate and compare LCOE of conventional and RES technologies, often made at the firm level. However, no study was found to investigate generation costs focusing on CCGT as a flexibility source during the energy transition.

Myhr, Bjerkseter, Ågotnes, and Nygaard (2014) compares the LCOE for offshore floating and standard bottom-fixed wind turbines. The influence of distance and water-depth is quantified in order to establish a threshold of competitiveness between them. Bruck, Sandborn, and Goudarzi (2018) calculate the LCOE for wind energy based on power purchase agreements, where the generation quantity is delimited. Park, Shin, and Yoon (2011) study the LCOE of fossil fuel power-plants, including CCGT. The costs are scrutinized regarding fuel and CO_2 prices and their changes, making use of three different scenarios from the IEA. The objective is to increase reliability of economic comparison of generation costs to be used on energy policy making.

IEA and NEA (2015) calculate LCOE for several countries and technology sources (gas, coal, nuclear, wind and solar) for plants entering operation in 2020. All calculations are made for three values of capital cost: 3%, 7% and 10%, and capacity factor is set at two values for each conventional source (e.g. at 50% and 85% for CCGT). Sensitivity analysis is performed differently for conventional and RES. For fossil and nuclear, the parameters observed are discount rate, overnight costs, lifetime, fuel and carbon costs and lead time. For wind and solar, sensitivity analysis is performed for capacity factor, discount rate, overnight costs and lifetime. The analysis is made at the plant level, so external effects are not considered.

EIA (2018b) calculates the LCOE for several types of generating technologies and for several regions in the US. The costs are estimated for plants entering operation in 2020, 2022 and 2040. No sensitivity analysis is performed, and the capacity factor adopted is the high-end of the technology`s likely utilization range. Externalities are not considered, as the analysis is also made at the plant level.

Kost and Schlegl (2013, 2018) analyse the LCOE for RES in Germany, with focus on solar energy. The study presents a regionally highly differentiated LCOE, to account for sunlight availability throughout the country. Wind energy costs and, for comparison purposes, gas and coal generation costs are also computed. The results are presented as an interval, which reflects the combination of variations in the input parameters (investment, fuel and emissions costs, and number of full load hours). Sensitivity analysis on investment, discount rate, O&M, lifetime, and full load hours (FLH) is performed for each RES technology. Externalities are not considered.

ENS (2015) calculates the socio-economic costs of electricity production using LCOE, with the objective to support public policies analysis. It includes system and society costs (e.g. GHG emission costs) and uses a social discount rate. Therefore, the study differs from the three LCOE aforementioned, that are calculated at the plant level. Externalities considered are: air pollution, climate, and costs of balancing, profile and grid.

2.4. Knowledge Gap and Research Question

The examined literature investigates several aspects of the impacts of RES on energy systems. The initial literature review was conducted using the TU Delft library website, the Science Direct portal and Google Scholar. The main research keywords used were: energy transition, Energiewende, Germany, generation cost, LCOE, CCGT, natural gas, capacity factor, full-load hours, energy policy, RES integration, security of supply, flexible generation and capacity mechanism. The articles used during the course SET3055 - Economics and Regulation of Sustainable Energy Systems from TU Delft, and their references, were also used as a starting point.

Based on the described search, no existing study was found oriented towards policy-making of the power sector that focuses on CCGT generation and its economic viability in the new paradigm of intermittency, neither for Germany or other EU member country. The debate to support the choice of a policy instrument that can maintain security of supply during the energy transition requires further investigation and data on CCGT competitiveness and externalities relevant for public policy. The risks of neglecting this problem are threat for energy security and a social inefficient policy outcome. Additionally, the literature does not converge on the expected capacity factor of CCGT generation, which is explored in this research.

Based on the problem introduced and the identified knowledge gap, the research question and sub-questions address the need for a better quantitative understanding of the competitiveness of CCGT generation in Germany during the energy transition, in order to create insights that can support the debate for public policy instruments.

Is CCGT generation a good option in terms of costs for the need of flexibility of the German power system during the energy transition, given increasing intermittency and risk to the security of supply?

The sub-questions are:

I. What is the expected capacity factor for CCGT generation in Germany during the energy transition?

II. From the perspective of a single firm, how does the reduced capacity factor for CCGT generation in Germany affect its competitiveness in terms of generation costs?

III. Taking into account the external costs, is CCGT generation a low-cost source of flexibility for the German power system?

3. Methods

3.1. Research Approach

The research objective is to investigate the electricity market and policy instrument that can provide flexibility for power systems in a socially efficient manner. Ultimately, this helps to secure power supply in face of a high level of intermittency due the large share of RES. The German power system is used as a case study, as it presents a large share of RES, it is an energy-only market and for which data is largely available.

The research performs a quantitative analysis of CCGT generation competitiveness, considered a suitable alternative of power source to deal with intermittency, in order to investigate whether and to what extent its economic viability is compromised by the diminished number of running hours. The investigation also analyses quantitatively the external costs from CCGT generation, especially the CO_2 cost, so policies can achieve a social optimum. In addition, energy storage competitiveness is investigated for comparison purposes. The results and discussion support an answer for the main research question.

The initial step for this research is to determine a range for the uncertainty that CCGT will face regarding the capacity factor. This answers sub-question I and uses secondary data. There are previous studies that determine this variable, but the values are divergent and there is no debate about the lack of consensus. Hence, a review of the values observed in the literature can determine an uncertainty range.

Sub-question II is answered by performing an investment appraisal and sensitivity analysis for CCGT generation. Since the idea is to scrutinize how the uncertain capacity factor affects its competitiveness, the focus of this sub-question is on the cost side of the appraisal. To investigate generation costs, a recognized method is the Levelized Costs of Energy (Konstantin & Konstantin, 2018a; Kost & Schlegl, 2018; Partridge, 2018). The LCOE is useful for this research as it condenses the future development and uncertainties of all cost variables into one single result value given in EUR/MWh.

To complement the answer for sub-question II, the sensitivity analysis method accounts for the uncertainty on CCGT generation's capacity factor. The uncertainty range is used to understand how this variable affects CCGT competitiveness.

Finally, for sub-question III, the initial focus is on carbon-dioxide costs, which strongly relates to the grand-challenge of climate change. The external costs are transformed to the same unit used for sub-question II (EUR/MWh), so it is possible to expand the competitiveness analysis. External costs are not considered by private firms, so they are considered for the appraisal from the government's perspective in order to compose a broader analysis of social efficiency.

The three sub-questions support a debate that can answer the main research question. In possession of quantitative data, the situation of CCGT generation economic viability against the backdrop of Germany's energy policy-framework becomes clearer.

3.2. Research Methods

This section presents the methods used in this research. The data required and the data sources are presented in sub-section 3.3.

3.2.1. Levelized Cost of Energy (LCOE)

Investment appraisal methods are used to compute and compare profitability and/or cost effectiveness of investments. The cash inflows and out-flows are considered under a discount rate (Konstantin & Konstantin, 2018a). The levelized cost of energy for a given generation plant is the constant price for power in real terms that would equate the net present value of revenue from the plant's output with the net present value of the cost of production (Borenstein, 2012). Hence, the method allows the comparison between the costs to construct and operate a CCGT power-plant, calculated in EUR/MWh, with other power source technologies and with wholesale market prices.

The idea of LCOE is to assess all costs incurred for a power generating unit and normalize them by the expected quantity of energy generation output, considering the investment's lifetime. This yields a cost per unit of energy for an investment alternative, appropriate to be compared with energy prices and the LCOE of other potential power-plants (Konstantin & Konstantin, 2018a; Kost & Schlegl, 2018).

The method considers all costs involved to build and operate a power-plant: capital cost, fixed and variable operations and maintenance costs, fuel and emission costs. All values are discounted in real terms to the reference date. Regarding the energy generation, the method uses an estimate of the output level for each year, also discounting it with the same rate. Equation (1) presents the formula for LCOE (EIA, 2017; Konstantin & Konstantin, 2018a).

$$LCOE = \frac{\sum_{t=0}^{n} \frac{Invest_t + \ fixed\_O\&M_t + var\_O\&M_t + Fuel_t + Carbon_t}{(1+i)^t}}{\sum_{t=0}^{n} \frac{W_t}{(1+i)^t}} \quad \left[\frac{€}{kWh}\right] \tag{1}$$

Where,

$Invest$ is the investment expenditure, that occurs in year 0;

$fixed\_O\&M_t$ is the operation and maintenance cost in year t that is independent of the output level;

$var\_O\&M_t$ is the operation and maintenance cost in year t that depends on the output level;

$Fuel_t$ is the cost to obtain fuel in year t;

$Carbon_t$ is the expenditure with emission allowances in year t;

W_t is the energy generated at the year t;

i is the discount rate;

n is the sum of the construction time and the lifetime of the investment project.

The electricity generated in a given year can be expressed as a function of the power-plant's installed capacity and the capacity factor in that year, as expressed in Equation (2).

$$W_t = Inst\_Cap \ . \ CF_t \ . \ 8760 \quad \left[\frac{CU}{kWh}\right] \tag{2}$$

Where,
Ins_Cap is the installed capacity of the plant;
CF_t is the capacity factor in year t;
8760 is the number of hours in a year.

3.2.2. Sensitivity Analysis

Saltelli, Tarantola, Campolongo, and Ratto (2004, p. 45) define sensitivity analysis as "the study of how the uncertainty in the output of a model (numerical or otherwise) can be apportioned to different sources of uncertainty in the model input". So, the method can be used to analyse a model's output uncertainty in a quantitative manner. Borgonovo (2017) argues that the method assists on model construction, use, calibration, corroboration, as well as to understanding how it works.

The method is applied in this research to analyse how the uncertain capacity factor of a CCGT power-plant, variable W_t in Equation (1), affects its levelized costs. The input interval is determined in sub-question I, and represents the effect that a large presence of RES in a power system has on the usage level of CCGT generation.

For this research, the model used is the LCOE formula described in Equation (1). The variable W_t has to be considered in the model using its entire distribution range to account for its uncertainty. The expected results for LCOE composes a range of costs, which can be then compared to electricity prices and energy storage costs.

3.2.3. External Effects

According to Ventosa et al. (2013, pp. 112-116), externalities are market failures and cause the total output to be inefficient. They state that "externalities arise when an economic agent (a consumer or a producer), is affected by another agent's production or consumption decisions, which are not taken into consideration by the latter in its production or utility function". The external effect can be positive or negative. So, it is possible to conclude that the analysis of CCGT generation as a policy instrument to deal with increased intermittency must include its external effects in order to achieve social efficiency.

Sub-question III expands the analysis made for sub-questions I and II. The first two sub-questions analyse how the large presence of RES can affect investment attractiveness for CCGT generation, and, consequently, if this option for flexibility is economically compromised or not. Although these results are a partial indicative for policy action, actual policy analysis must consider externalities from natural gas generation. Therefore, the idea is to collect quantitative secondary data on external costs of CCGT and to converted it into the same unit used in the investment appraisal, so it can be compared to energy prices and costs. Within the energy transition policy arena, the most prominent externality is the cost of GHG emission (negative externality).

3.3. Data requirement

The data required to answer each of the three research sub-questions is presented in Table 2. For all questions, the data collection makes use of academic articles as well as of publications and database from public agencies, from Germany and abroad.

The journals to be considered are from the fields of energy, energy policy and environmental policy, such as, but not limited to: Energy Policy, Energy Economics, Energy, The Energy Journal, Review of Environmental Economics and Policy, Journal of Environmental Economics and Management, Global Environmental Politics and Ecological Economics. The academic literature is especially suitable for sub-questions I and III.

The institutes to be considered are the International Energy Agency (IEA), the Fraunhofer Institute for Solar Energy Systems (Fraunhofer ISE), the Danish Energy Agency (ENS), the International Renewable Energy Agency (IRENA) and the US Energy Information Administration (EIA). These institutes publish several open and data-rich reports, that are especially useful for sub-questions I and II.

Table 2. Data requirement for each research sub-question

Phase	**Sub-question I**	**Sub-question II**	**Sub-question III**
Goal	*Examine running hours uncertainty for CCGT*	*Assess CCGT cost-competitiveness for private firms*	*Assess CCGT cost-competitiveness for society*
Data required	Current full running hours *[hours / year]*	Capacity factor range *[%]*	Efficiently set pollution cost *[€ / tonCO_2]*
	Projected full running hours *[hours / year]*	Investment cost *[€ / MW_i]*	Generation efficiency factor *[%]*
		Interest rate *[%]*	
		O&M Fixed & Variable *[€ / MW_i & € / MWh]*	
		Fuel & Emission costs *[€ / MWh]*	
		Decommissioning cost *[€ / MW_i]*	
		Installed capacity *[MW_i]*	
		Lifetime of project *[years]*	
		Electricity prices *[€ / MWh]*	
		Energy storage cost *[€ / MWh]*	

MWi stands for installed capacity of the power-plant, and MWh for generated energy in a given year.

4. Data

This section presents the data collection necessary for the research, as presented in Table 2. First, the data sources are described. Then, the collected data is presented following the phases of this research: capacity factor examination, LCOE calculation, and external costs.

All monetary values were converted to 2017 Euro. The Dollar values were converted to Euro of their reference year using the annual reference exchange rate (EXR.A.USD.EUR.SP00.A) from the European Central Bank. With all currency data given in current Euros, all values were transformed into 2017 Euros using the German Producer Price Index (BBDP1.A.DE.N.EPG.G.GP09SA000000.I10.L) as given by the German central bank Deutsche Bundesbank.

4.1. Data Sources

4.1.1. International Energy Agency and Nuclear Energy Agency

The agencies published the report *Projected Costs of Generating Electricity - 2015 Edition*. The report calculates the LCOE of several generation technologies, including CCGT, for units entering operation in 2015.

IEA establishes two scenarios of future prices for natural gas and CO_2 emission allowances that are used in this research for LCOE calculation. The first is the New Policy scenario, that is based on the “relevant existing or planned policies, (…) consistent with the course on which governments appear at present to be embarked”. Therefore, the forecast of CO_2 emission allowances is a progression of current prices, and natural gas price is relatively high, as a result of growing demand. The second is the 450ppm scenario, which highlights the “policy, technology development and investments required to meet a global 2 °C climate change target, and quantifying the additional effort needed” (IEA, 2017, pp. 129-131). Hence, it reflects additional and more strict policies on GHG emission and higher CO_2 allowance price.

4.1.2. Fraunhofer ISE

The institute published the report *Levelized Cost of Energy – Renewable Energy Technologies*. The study investigates the expected evolution of RES generation costs in Germany using the LCOE method. For competitiveness comparison purposes, conventional generation is also investigated, including CCGT

4.1.3. Danish Energy Agency (ENS)

The agency published the report *Finding your Cheapest Way to a Low Carbon Future – The Danish Levelized Cost of Energy Calculator*. The objective is to investigate the social costs of the available electricity generation technologies options, so as to facilitate long-term policy decisions regarding public investment in the power sector. Adopting the government’s perspective on the system, the concept of external costs and benefits was integrated with LCOE calculations. Conventional generations sources and RES were reviewed, including CCGT. The study estimates the LCOE for plants entering operation in

2016. Hence, it reports forecasts for each LCOE variable for their lifetime, including the value for the number of full load hours.

The agency also published the report *Technology Data for Energy Plants for Electricity and District heating generation - August 2016*, in cooperation with Energinet, the Danish transmission system operator. It contains a dataset on financial factors for several generation technologies and serves a base for other studies, corresponding to 'best available technology' commissioned in 2015 in Denmark (ENS & Energinet, 2016). However, it does not include data on capacity factor.

4.1.4. Agora Energiewende

The think tank published the report *Calculator of Levelized Cost of Electricity for Power Generation Technologies*. The tool is a spreadsheet intended to enable users to "calculate the cost for electricity produced by different power generation technologies under different assumptions". The LCOE results refer to new power-plants in 2015. The tool uses data from Institute of Energy Economics at the University of Cologne.

4.1.5. U.S. Energy Information Administration

The agency published the report *LCOE and LACE of New Generation Resources in the Annual Energy Outlook 2018*. It presents the estimates of levelized costs and of avoided costs of energy, LCOE and LACE respectively, that are used for the model that feeds the agency's Annual Energy Outlook. The study considers plants entering operation in 2020, 2022 and 2040, for 22 regions in the United States. The results are presented in capacity-weighted and simple average of these regions (EIA, 2018b). The agency also published the report *Cost and Performance Characteristics of New Generating Technologies* EIA (2018a). These reports are updated annually to compose their Annual Energy Outlook.

4.1.6. Konstantin & Konstantin

The authors published two books in the series *Best Practice Manual*: *Power Supply Industry- Best Practice Manual for Power Generation and Transport, Economics and Trade* (2018b), and the *Power and Energy Systems Engineering Economics- Best Practice Manual* (2018a). They provide a "comprehensive coverage of engineering economics required for techno-economic evaluation of investments in the energy supply business".

4.1.7. German Federal Environmental Agency (UBA)

The Umweltbundesamt (UBA) is the German Federal Environmental Agency. It published the report *Environmental Costs in the Energy and Transport Sectors - Recommendations by the Federal Environment Agency*, containing a summary of costs from climate change and air pollution. The report is focused in the energy and transport sectors, and include the external cost values for several activities, including the cost specifically for CCGT generation in Germany.

The agency also published the *Economic Valuation of Environmental Damage – Methodological Convention 2.0 for Estimates of Environmental Costs*, and two annexes. Annex B is names *Best-Practice Cost Rates for Air Pollutants, Transport, Power Generation and Heat Generation*, that presents a discussion on methods to quantify and monetize emissions of GHG and air pollutants.

4.1.8. International Renewable Energy Agency (IRENA)

The Agency published the report *Electricity Storage and Renewables- Costs and Markets to 2030*. The author establishes values for cost components of several ES technologies, for both current experiences and expected future developments. IRENA also published its *Cost-of-Service tool version 1.0*, where the cost of several ES technologies is calculated, levelized for their lifetime and level of use. The tool assumes different values of installed power capacity, energy-to-power rate, and cycles per day depending on the service performed (e.g. energy shifting, frequency regulation). For the research objectives of this study, only the Energy Shifting service is considered, as it reflects the long-term bulk energy management to be compared with CCGT generation.

4.2. Data Collection on the Capacity Factor Uncertainty of CCGT Generation

This section presents the collected data to answer the research sub-question I: *'What is the expected capacity factor for CCGT generation in Germany during the energy transition?'*. The required data is presented in Table 2, and the collection method used was desk research.

Among the data sources considered in Section 4.1, the following contain forecast on capacity factor or full-load hours for CCGT power-plants: International Energy Agency and Nuclear Energy Agency, Fraunhofer ISE, Danish Energy Agency, Agora Energiewende, US Energy Information Administration, and Konstantin & Konstantin. The collected data is presented below for each data source, and the discussion and results are presented in Section 5.

4.2.1. International Energy Agency and Nuclear Energy Agency

The capacity factor for the CCGT technology established by the agencies is of 85% and 50%. The collected data is presented in Table 3. The authors also determine the capacity factor for other countries, ranging from a lower bound of 35% to a higher bound of 93%.

4.2.2. Fraunhofer ISE

For CCGT generation, the report stablishes the expected number of FLH until 2035. The technology achieves FLH between 2.000 and 5.000 hours in 2018, and the average is 3.500 hours. For the following years, the study estimates a continuous reduction of 0,5% per year on CCGT's FLH. So, the expected average FLH value for CCGT in 2035 is 3.100 hours. The collected data of FLH is converted to capacity factor format and presented in Table 3.

4.2.3. Danish Energy Agency

For the CCGT technology, FLH is set on 5.000 hours for all operational years, which corresponds to a capacity factor of 57,1% for the 30 years of lifetime. The collected data is presented in Table 3.

4.2.4. Agora Energiewende

Agora Energiewende adopts a range for the number of FLH between 2.000 and 4.000 hours (Agora Energiewende, 2014). The collected data is presented in Table 3.

4.2.5. U.S. Energy Information Administration

For the CCGT technology, the estimate is of an 87% capacity factor for the entire analysed period. The report also includes a technology called Advanced CCGT[4], that uses the same capacity factor as the conventional CCGT (EIA, 2018b). The collected data is summarized in Table 3.

4.2.6. Konstantin & Konstantin

The estimations for full load hours is given in a case study to calculate generation costs for fossil fuelled power-plants. For CCGT generation, FLH is proposed as 5.000 hours/year. The authors also consider a factor of 3% of forced outages, resulting an actual full load hours of 4.850 hours/year. The collected data is summarized in Table 3.

Table 3. CCGT generation capacity factor, in %.

	(IEA & NEA, 2015)	(Kost & Schlegl, 2018)*	(ENS & Energinet, 2016)	(Agora Energiewende, 2014)	(Konstantin & Konstantin, 2018b)
2013	50%			22,8% | 45,7%	
2015			57%		
2017					55,4%
2018		23% | 40% | 57%			
2020		23% | 39% | 57%			
2025		22% | 38% | 55%			
2030		21% | 37% | 54%			
2035		21% | 35% | 52%			

* Data points established for each operational year.

4.3. Data Collection for LCOE of CCGT Generation

This section presents the collected data to answer the research sub-question II: *'From the perspective of a single firm, how does the reduced capacity factor* for CCGT generation in Germany affect its competitiveness in terms of generation costs?*'*. The required data is presented in Table 2, and the collection method used was desk research.

[4]EIA (2018b) uses the nomenclature of Conventional CCGT and Advanced CCGT. The former refers to the CCGT technology as defined previously in this research. The latter corresponds to a technology characterized by higher investment cost and lower operating cost.

First, this section introduces and commentates each variable and parameter necessary for the LCOE calculation. Other parameters are necessary to calculate the LCOE that are not explicitly expressed in Equation (1): installed capacity, construction time, fuel efficiency, emission factor, fuel and emission prices. Konstantin and Konstantin (2018b) categorizes the data under technical, financial and economic parameters, as shown in Table 4. The collected data for the CCGT technology is then presented, summarized in two tables. Appendix A presents more details of the data collection.

This part examined the datasets established by IEA & NEA, Kost and Schlegl, ENS, Agora Energiewende, EIA and Konstantin and Konstantin. The discussion and results on LCOE and sensitivity analysis are presented in Section 5.

Table 4. Data requirement for LCOE calculation of CCGT power-plants divided into categories, adapted from Konstantin and Konstantin (2018b).

Category	Variables
Technical parameters of CCGT power-plants	• Installed capacity, • Project lifetime, • Construction time, • Fuel efficiency, and • Emission factor.
Financial parameters of CCGT power-plants	• Investment cost, • Fixed O&M cost, • Variable O&M cost, and • Decommissioning cost.
Economic parameters for CCGT power-plants	• Cost of capital, • Fuel cost, and • Emission cost.

4.3.1. Installed Capacity

Installed capacity refers to net installed capacity of a power-plant, i.e. the power it is able to deliver to the electric grid or busbar. The net capacity is calculated as the gross installed capacity minus its own auxiliary consumption (ENS & Energinet, 2016). In turn, gross installed capacity is also referred to generator nameplate capacity and is defined as “the maximum rated output of a generator, prime mover, or other electric power production equipment under specific conditions designated by the manufacturer” (EIA, n.d.). For the LCOE calculation, the net installed capacity is used. The values are given in MW or MW_i, that stands for MW installed.

The obtained data is presented in Table 5. The following studies establish a value or a range of values for CCGT power-plant installed capacity: IEA and NEA (2015); Kost and Schlegl (2018); ENS and Energinet (2016); EIA (2018a); Konstantin and Konstantin (2018b).

4.3.2. Project Lifetime

The project lifetime parameter refers to the period of time that a power-plant operates and generates electricity. It composes the variable n in Equation (1) and is measured in years. The lifetime count starts after the plant's construction is finished and power generation commences. Following the literature, this research considers the technical lifetime for the LCOE calculation.

The collected data is presented in Table 5. The following studies establish a value for CCGT power-plant lifetime: IEA and NEA (2015), Kost and Schlegl (2018), ENS and Energinet (2016), Agora Energiewende (2014), EIA (2018a), Konstantin and Konstantin (2018b).

4.3.3. Energy Conversion Efficiency

Energy conversion efficiency relates to the "total delivery of electricity to the grid divided by the fuel's energy content consumption" (ENS, 2015, p. 14). Efficiency is given in percentages and are calculated for a determined set of ambient conditions. This parameter is not a direct variable in Equation (1), but it is necessary to calculate the fuel and emission costs, $Fuel_t$ and $Carbon_t$ respectively.

A power-plant efficiency is used to convert its fuel's energy income into its electrical energy output. Both can be expressed in MWh for convenience but, to avoid confusion, it is usually the case to denote fuel energy values in MWh_{therm}.

The collected data is presented in Table 5. The following studies establish a value or a range of values for CCGT energy conversion efficiency: IEA and NEA (2015), Kost and Schlegl (2018), ENS and Energinet (2016), Agora Energiewende (2014), EIA (2018a), Konstantin and Konstantin (2018b).

4.3.4. CO_2 Emission Factor

Emission factor is "the average emission rate of a given GHG for a given source, relative to units of activity" (UNFCCC, n.d.). The factor is used to calculate the emission costs $Carbon_t$ in Equation (1), and can is usually given as a unit of mass over a unit of energy, such as ton/kWh_{therm}, kg/GJ and lb/MMBtu. The unit adopted for this parameter is the $tonCO_2/MWh_{therm}$.

The collected data for CO_2 emission factor is presented in Table 5. The following studies establish a value or a range of values for CCGT power-plant CO_2 emission factor: Kost and Schlegl (2018), ENS and Energinet (2016), Agora Energiewende (2014), EIA (2018a), Konstantin and Konstantin (2018b).

4.3.5. Construction Time

The construction time is the period of time that takes "from financial closure of building the respective plant until the plant is ready to operate". This parameter is relevant for the LCOE calculation as it influences the variable n in Equation (1). Additionally, the investor incurs interest payments during the construction time and is unable to generate revenues with energy sales (ENS, 2015).

The collected data for CCGT power-plant construction time is presented in Table 5. The following studies establish a value or a range of values for CCGT power-plant construction time: IEA and NEA (2015), ENS and Energinet (2016), EIA (2018a), Konstantin and Konstantin (2018b).

4.3.6. Investment Cost

Investment cost is the necessary initial capital disbursement to construct and equip the power-plant so it can start operation. The examined datasets establish each the investment cost and/or the overnight cost for CCGT power-plants, given in a monetary unit per MW_i. To build a complete cost stream to calculate the LCOE, it is necessary to use the overnight cost as occurring in first year ($n = 0$) and consider the interest payments that occur in the construction time.

The studies that calculate the overnight costs are: IEA and NEA (2015), ENS (2015), EIA (2018a), Konstantin and Konstantin (2018b). The studies that compute investment cost are: (IEA & NEA, 2015), (Kost & Schlegl, 2018), (ENS, 2015), (ENS & Energinet, 2016), (Agora Energiewende, 2014). For the latter group, this research transformed the values for investment cost into overnight costs using the respective values for construction time and interest rate. Consequently, all overnight cost data is in a common basis and given in EUR_{2017} per MW_i. The collected data is presented in Table 5.

4.3.7. Fixed O&M costs

Operation and maintenance costs (O&M) are “cash outflows during the operation phase of a project, e.g., for fuels, personnel, maintenance”, also referred to as operating expenses (OPEX) (Konstantin & Konstantin, 2018b, p. 353). O&M costs are divided in fixed and variable, conditional to whether or not they are dependent on the energy output level of the power-/plant (ENS, 2015).

The datasets that present data on fixed O&M costs for CCGT power-plants are: Kost and Schlegl (2018), ENS and Energinet (2016), Agora Energiewende (2014), and EIA (2018a). They are presented in Table 5.

4.3.8. Variable O&M costs

As defined on the previous section, O&M costs are expenses during the operational period of a power-plant. In particular, variable O&M costs are those which depend on the generation output level of the plant.

The datasets that present data on variable O&M costs for CCGT power-plants are: Kost and Schlegl (2018), ENS and Energinet (2016), and EIA (2018a). The collected data is presented in Table 5.

4.3.9. Discount Rate

The discount rate is used to calculate the present value of a future cost. The LCOE method for an investment appraisal uses a discount rate that reflects the cost of borrowing and of desired returns from the investing firm (ENS, 2015; Konstantin & Konstantin, 2018a).

The studies that report a value for the discount rate are: (Kost & Schlegl, 2018), (Agora Energiewende, 2014), (EIA, 2018b), and (Konstantin & Konstantin, 2018b). These four publications use the WACC method. IEA (2018) reports three values, from which two refer to market conditions and one reflects a social cost of capital. ENS (2015) also establishes a value that reflects social preferences. The collected data is presented in Table 5, all in real terms.

4.3.10. Fuel cost

Fuel cost refers to the expenses with the natural gas necessary to generate one unit of electrical energy. It is determined by the natural gas price and the power-plant efficiency. Natural gas prices are given in a currency unit per either an energy or a volume unit, e.g. EUR/MMBtu or EUR/m^3. This research adopts the unit of EUR_{2017}/MWh_{therm}. MWh_{therm} is a unit of energy that is used to express fuel energy content and that is convenient to transform into electrical energy measures in MWh, considering the power-plant's conversion efficiency.

The studies that report a time-series forecast of natural gas prices are: (Kost & Schlegl, 2018), (ENS, 2015), and (Agora Energiewende, 2014). (IEA & NEA, 2015) also establishes two values, but they are given as a single, fixed values to be used for every operational year. The collected data is presented in Table 6.

4.3.11. Emission cost

Emission cost represents the expenses the plant operator incurs with emission rights in order to generate one unit of electrical energy. It is determined by the CO_2 emission allowance price, the CO_2 emission factor of natural gas and the power-plant efficiency. Emission right prices are given in a currency unit per tonne of CO_2. For convenience, the values are transformed to EUR_{2017}/MWh_{therm}.

Emission costs are the variable $Carbon_t$ in Equation (1) and are expressed in its final value for the electricity generated, i.e. the emission right cost divided by the efficiency. The data collection of this section focuses on emission right price, as data for conversion efficiency and emission factor are covered above. The studies that report a time-series forecast of emission right prices are: (Kost & Schlegl, 2018), (ENS, 2015) and (Agora Energiewende, 2014). (IEA & NEA, 2015) also establishes two values, but they are given as a single, fixed values to be used for every operational year. The collected data is presented in Table 6.

Table 5. Summary of collected data for LCOE the calculation of CCGT generation.

	(IEA & NEA, 2015)	(Kost & Schlegl, 2018)	(ENS & Energinet, 2016)	(Agora Energiewende, 2014)	(EIA, 2018a)	(Konstantin & Konstantin, 2018b)
Installed Capacity [MW_i]	500	400	600		429 - 702	404
Project Lifetime [years]	30	30	30	30	30	25
Energy conversion efficiency [%]	60%	60% - 62%	59% - 61%	52% - 60%	52%	60%
CO_2 emission factor [$tonCO_2/MWh_{therm}$]		0,200	0,205	0,202	0,181	0,202
Construction time [years]	2		2 - 2,5		3	2,5
Investment cost [1000 EUR/MW_i]	719	760 - 1.045	758 - 873	647 - 788	869	833
Fixed O&M cost [1000 EUR/MW_i]		22,0	26,2 - 30,3	19,6 - 27,6	11,1	
Variable O&M cost [EUR/MWh]		4,0	4,0 - 4,5		3,1	
Discount rate [%]	3%*, 7%, 10%	5,2%	4%*	6% - 12%	3,7% - 4,5%	6,5%

* Denotes a social discount rate.

Table 6. Collected data of fuel and emission right prices, in EUR_{2017}/ MWh_{therm} for each operational year.

	(IEA & NEA, 2015)*		(Kost & Schlegl, 2018)		(ENS, 2015). Scenario 1		(ENS, 2015). Scenario 2		(ENS, 2015). Scenario 3		(Agora Energiewende, 2014)	
cost	**Fuel**	**Emission**	**Fuel**	**Emission**	**Fuel**	**Emission**	**Fuel**	**Emission**	**Fuel**	**Emission**	**Fuel**	**Emission**
2013	28 - 33	3,9 - 4,4			34,7	0,9	34,7	0,9	34,7	0,9	22,2	1,6
2014					25,7	1,2	25,7	1,2	25,7	1,2	22,5	1,8
2015					25,3	1,4	24,5	1,4	25,3	1,4	22,7	2,2
2016					25,4	1,8	24,8	1,8	25,7	1,7	22,9	2,6
2017					25,0	2,1	24,6	2,1	25,7	2,0	23,4	2,9
2018			21	1,06	24,6	2,4	24,4	2,4	25,7	2,3	23,8	3,3
2019					24,4	2,8	24,4	2,8	25,9	2,6	24,2	3,7
2020			25,1	1 - 3	24,2	3,1	24,4	3,1	26,1	2,9	24,6	4,1
2021					23,6	4,3	24,2	3,4	26,2	3,0	25,0	4,4
2022					23,2	5,4	24,2	3,6	26,4	3,1	25,5	4,8
2025			27,1	2,5 - 6,5	23,2	8,7	25,3	4,2	28,3	3,6		
2030			32,2	4 - 10	26,7	14,3	30,8	5,3	35,5	4,3		
2035			33,8	6 - 14	25,9	17,1	32,5	6,2	37,3	5,0		
2040					25,2	20,0	34,1	7,1	39,1	5,7		
2045					24,5	22,8	35,7	8,1	40,9	6,4		
2050					23,7	25,7	37,3	9,0	42,7	7,1		
2075					23,7	25,7	37,3	9,0	42,7	7,1		

* Given in a single fixed value to be used for every operational year.

4.4. Data Collection for Energy Storage

Data on energy storage costs is used in this research for comparison purposes with CCGT generation costs. The ES technologies that can offer flexibility similarly as CCGT generation are CAES, PHS and VRFB, as identified in Section 2.1.8. For the research objectives of this study, only the Energy Shifting service is considered, as it reflects the long-term bulk energy management. The resulting value for the lifetime levelized costs is named Levelized Cost of Energy Storage (LCOES) in this research.

Two data sources cover ES costs: (IRENA, 2017) and (ENS, 2012). Table 7 presents the collected data on the LCOES for CAES, PHS, and VRFB for the service of energy shifting. Reference cases are presented along with best and worst cases.

Table 7. Collected data on LCOES of CAES, PHS, and VRFB, in EUR_{2017}/MWh.

	CAES			PHS			VRFB		
	Best case	**Refer. case**	**Worst case**	**Best case**	**Refer. case**	**Worst case**	**Best case**	**Refer. case**	**Worst case**
2016	60,2	123,2	199,9	59,8	77,2	152,7	190,9	270,3	1.030
2020	55,1	111,6	182,0	59,8	77,2	152,7	148,4	204,5	713,0
2025	52,3	105,4	172,4	59,8	77,2	152,7	111,8	149,2	459,3
2030	51,4	103,1	168,3	59,8	77,2	152,7	87,5	113,3	304,4

4.5. Data Collection for External Costs

This section presents the collected data to answer the research sub-question III: *'Taking into account the external costs, is CCGT generation a low-cost source* of flexibility for the German power system*'*. The required data is presented in Table 2, and the collection method used was desk research.

The cost for society originated from GHG and air pollutants can be expressed in a cost rate, given in a monetary per mass unit of the emission, e.g. EUR/tonCO_2 or EUR/tonSO_2. The other parameters necessary to calculate the external cost are the emission factors of the fuel in question and the efficiency of the power-plant. The emission factors are calculated for each GHG and air pollutant and given in kg per unit of fuel energy, e.g. kg/GJ of fuel. To obtain the climate change cost incurred by society, the emission factors of the GHG are multiplied by the CO_2 cost rate and the power-plant efficiency. Similarly, the social cost of air pollution is obtained by multiplying the fuel's air pollutants emission factors by their cost rates and the plant's efficiency. The result is then expressed in EUR/MWh.

Two sources were considered to collect data on external costs from CCGT generation. The first is the report ENS (2015), named *Finding your Cheapest Way to a Low Carbon Future – The Danish Levelized Cost of Energy Calculator*. The second source is the German Federal Environment Agency (Umweltbundesamt, or UBA), that published the reports UBA (2014), named *Environmental Costs in the Energy and Transport Sectors - Recommendations by the Federal Environment Agency*, and UBA (2012), named *Economic Valuation of Environmental Damage – Methodological Convention 2.0 for Estimates of Environmental Costs*.

The collected data is presented below: first the cost rates of CO_2 and air pollutants are presented, followed by the emission factors of natural gas. Finally, data collected on the end result of external costs from CCGT generation is presented. The energy conversion efficiency of a CCGT power-plants is already covered in Section 4.3. The results obtained and discussion of impacts on CCGT generation costs are presented in Section 5.6.

4.5.1. Cost Rates of GHG and Air Pollutants

The cost of carbon dioxide (CO_2) emission is referred to as cost rate of CO_2 and given in monetary value per tonne of CO_2. The impact of other GHGs are estimated in the same way as for CO_2 and be expressed in CO_2 equivalent. The literature indicates that the most relevant GHG are carbon dioxide, methane (CH_4) and nitrous oxides (N_2O). CH_4 has global warming potential 25 times higher than CO_2, and N_2O 298 times higher (ENS, 2015; UBA, 2012).

The collected data is presented in Table 8. UBA (2014) reports the CO_2 cost rate for the short, medium and long-term (years 2010, 2030 and 2050) using the damage cost method. ENS (2015) uses CO_2 pricing according to IEA (2015, p. 42): it uses three scenarios (Current Policies, New Policy and 450 Scenario) and determine values for 2015, 2020, 2030 and 2050. Regarding air pollution, the cost rates follow the premise to estimate environmental and health costs due to gas and particles pollutants. They are given for each emission product in a monetary value per tonne of emission. UBA (2012) establishes the air pollutants cost rates specifically for Germany. ENS (2015) establishes values with focus on Europe.

Table 8. Collected data on cost rate of CO_2, per year of emission, and air pollutant, in fixed values. Given in EUR_{2017}/ ton.

CO_2 Cost Rate						
	UBA Minimum Figure	UBA Average Figure	UBA Maximum Figure	ENS New Policy	ENS 450ppm	ENS Current Policies
2010	42	84	126			
2015				7	7	7
2020				17	17	15
2030	73	152	225	28	74	23
2040				38	105	30
2050	136	272	409			

Air Pollutants Cost Rate		
	UBA	ENS
SO_2	13.834	12.640
NO_X	16.139	6.569
$PM_{2,5}$	58.059	3.185

4.5.2. Emission Factors of Natural Gas

ENS (2015) establishes the GHG and air pollutants emission factors for natural gas and other fossil fuels. UBA (2012), on the other hand, does not present values for this parameter. The collected data is presented in Table 9. Data for coal is also presented for comparison purposes.

Table 9. Collected data on GHG and air pollutants emission factors, in g / GJ of fuel.

	Natural Gas	Coal
CO_2	57.000	94.000
CH_4	1,5	1,5
N_2O	1	0,8
SO_2	0	270
NO_X	39	196
$PM_{2,5}$	0	13

4.5.3. External Cost of CCGT Generation

UBA (2014) reports the final external costs of CCGT generation in EUR/MWh. ENS (2015) does not present explicitly such values, but it is possible to calculate them using its LCOE calculator tool. The collected data is presented in Table 10. These values are obtained from the expected direct and indirect GHG and air pollutant emission from a CCGT power-plant throughout its lifetime (i.e. emission from natural gas combustion and from the activities related to its construction and decommissioning) and the costs rates above. The discount rates used to obtain the present value of the costs are 1% for climate change costs and 1,5% for air pollution costs.

Table 10. Collected data on Total External Cost of CCGT Generation, in EUR_{2017}/MWh.

	(UBA, 2012)	(ENS, 2015)
Climate Change Cost	40,9	18,4
Air Pollution Cost	10,7	2,0
Total External Cost	51,5	20,4

4.5.4. External Costs of ESS

External costs of ESS are proposed by Denholm and Kulcinski (2004). GHG emissions occur during the installation and decommissioning processes, and are related to the economic activity involved for the necessary material and equipment. Emission during operation is considered null as there is no fuel combustion (it is assumed that the CAES technology uses an advanced-adiabatic process to store heat). The collected data presented in Table 11 is given in tonnes of CO_2 per installed quantity energy storage (MWh_i).

Table 11. GHG emission of ESS, in $tonCO_2$ / MWh_i.

	CAES	PHS	VRFB
GHG emission [$tonCO_2$ / MWh_i]	19,0	35,7	161,0

5. Results and Discussion

This section presents the results obtained with the application of the research methods. First, it introduces a discussion on the collected data for the input variables of LCOE calculation. By scrutinizing each variable, it is possible to selected values that compose an appropriate scenario for CCGT generation in Germany for the next decades. Then, the results for the range of capacity factor, LCOE calculation, sensitivity analysis, and energy storage costs are presented. Later, the results for external costs of gas generation and for energy storage are given. Finally, a discussion on the results is presented and combined with the multi-actor analysis.

5.1. Input Variables for LCOE Calculation

This section presents a discussion on each input variable necessary to calculate the LCOE of CCGT generation. First, the capacity factor is analysed. Then, the technical, financial, and economic variables are discussed. This research selects values for each variable that best correspond with the assumptions and objectives of this research, and apply them to calculate the LCOE and to perform sensitivity analysis, in Sections 5.3 and 5.4. The relevant collected data is presented in Section 4.2 and 4.3.

5.1.1. Capacity Factor

International Energy Agency and Nuclear Energy Agency

The agencies use a standard capacity factor of 85% for CCGT, coal, and nuclear generation. It represents the average expected utilization of these types of power-plants for the time-horizon of 30 years. Although it is not explicitly stated, it is possible to infer that the LCOE model considers this fixed value to compute the energy output for all years in the time series.

The authors mention that a capacity factor of 85% is higher than what is observed in practice, especially for CCGT, given that relatively high marginal generation costs can lead the plant operator to cease generation during baseload and low market prices periods. Also, the study recognized that CCGT is more commonly used during mid-load or even peak-load hours. Nevertheless, a common capacity factor was used for the three technologies, under the argument that “the overarching concern here is with baseload capacity”. Therefore, the choice of the capacity factor at 85% relates to the use of CCGT to provide baseload energy (IEA & NEA, 2015, p. 31).

The publication also uses a second value of capacity factor to perform sensitivity analysis of LCOE. The objective is to investigate the influence of number of running hours on the levelized costs. Hence, the study adopts a capacity factor of 50% for the sensitivity analysis of the three previously mentioned technologies. The choice of this value is based on the premise that “it is far enough from 85% to show the impact on LCOE without being so low as to present results that are unreasonable under any circumstances”. It is argued that this value is not a representation of the capacity factor expected for these technologies in the future (IEA & NEA, 2015, p. 57).

This study collected data provided by member country governments directly or by experts nominated by those countries. From a total of 181 responses, there were 13 for the CCGT technology spread throughout 12 countries. The data for the German case was derived from publicly available sources. Regarding the capacity factor variable of other countries, the responses ranged from 35% to 93%. It is worth noting the wide range of the dataset for other countries on future CCGT utilization rate.

Fraunhofer ISE

The research's objective is to investigate the generation costs for solar, wind and biomass technologies, with focus on photovoltaic, wind turbines and biogas. The expected evolution of costs is explored by calculating the LCOE of new plants entering operation on each of the next 15 years. The concept of learning curves is used. Hence, the results are time series of levelized costs from 2018 to 2035 for plants of each technology. LCOE time series for brown coal, hard coal, CCGT, and gas turbine technologies allow comparison of current competitiveness of RES against conventional sources and its expected evolution.

The authors report a value of annual values for the capacity factor variable, different from most of the other datasets. So, it is possible to observe the tendency of running hours to fall for CCGT power-plants. The main argument for the reduction is that the undergoing German power sector transformation and that the increasing generation from RES reduce the residual load.

The data is given in FLH and was converted to capacity factors values. Given that one year has 8760 hours, the authors establish the current capacity factor in Germany for CCGT ranges from 23% and 57%, and the average at 40%. They state that the expected average factor in 2035 is of 35%. Using a constant reduction factor of 0,5% per year, assumed by the authors, it is possible to interpolate the values for the intermediate years. It is worth noting that the authors determine a lower and higher bound for the variable and that the latter is approximately 150% higher than the former.

Danish Energy Agency

The authors argue that the study assumes natural gas, coal, and biomass to serve between baseload and mid-load. The publication also consists of a spreadsheet with the dataset and the LCOE calculation, in which the user may adjust the input variables. Although the authors do not state explicitly, it is possible to infer that the choice of the fixed value of 57,1% for three considerably distinct technologies is made in order to allow cost comparison on the same basis. Moreover, the focus on the baseload a mid-load periods reinforces the pursuit for socially optimum cost of the power system.

Agora Energiewende

The authors present estimates on capacity factor specifically for each technology. CCGT generation has the lowest utilization rate among the conventional sources, ranging from 22,8% to 45,7%. It also represents a larger variance than the one proposed for wind and solar power: 23% to 29% for wind power and 11% for solar with no variance. The data is provided as the average for the lifetime of the project, so it is not possible to observe its behaviour over time.

U.S. Energy Information Administration

The study assumes a value for the capacity factor of each technology at the highest value of their utilization range. The authors present a brief discussion for this choice, arguing that this criterion makes the cost comparison among different technologies more robust. However, the value of 87% relates more strongly to coal and nuclear generation, as they serve the baseload. On the other hand, the CCGT technology is generally more used for "load-following or other intermediate dispatch duty cycles", although it can also be used to serve baseload. The debate is concluded by indicating that the simple combustion turbine (CT) is a technology oriented towards serving peak-load and that its highest expected utilization rate is 30% (EIA, 2018b).

So, the report assumes an elevated value for CCGT generation capacity factor under the premise it can serve baseload, at the same time it considers it a technology more suited for load-following. Yet, it does not present an alternative value that differentiates it from coal or nuclear generation.

5.1.2. Installed Capacity

The net installed capacity value correspond to typical installations and depend on the equipment choice and its manufacturer. An investor can opt for a larger, multiple-unit power-plant installation, where there are economies of scale (IEA & NEA, 2015). This option is not considered in the reviewed literature nor in this research. This parameter influences all variables in Equation (1), apart from the lifetime and discount rate.

The examined data of installed capacity fall into a narrow range between 400 and 700 MW_i. There is some flexibility to the choice of installed capacity, as the ENS and Energinet (2016) presents a range from 100 and 500 MW_i.

Observing the data, it is possible to select one value for this variable, instead of a distribution. There is little variance concerning this variable and the other technical parameters. Given the convergence of the points around 500MW_i, this is the value to be considered for the installed capacity.

5.1.3. Project Lifetime

The data sources examined consider the technical lifetime of the power-plant for their economic assessment. ENS (2015, p. 16) states that it is also possible to consider a financial lifetime, for instance "the maturity period of the debt finance", that is usually shorter than the technical lifetime. However, doing so would require stablishing a scrap value for the last year of the financial lifetime. Following the literature, this research considers the technical lifetime for the LCOE calculation.

The data points cluster around 30 years for a CCGT power-plant lifetime. All but one study determines the variable as 30 years. The exception is Konstantin and Konstantin (2018b), that stablishes the variable at 25 years, 17% lower than the others.

Observing the data, this study selects one value for this variable, instead of a distribution. There is little variance concerning this and the other technical parameters. Given the convergence of the points around 30 years, this is the value to be considered for the project lifetime.

5.1.4. Energy Conversion Efficiency

Among the examined data sources, the ENS and Energinet (2016) was the only study to state the ambient conditions for the calculated fuel efficiency: “air and water temperatures of 15°C and 10°C, at full load (100%), continuous operation, on an annual basis, taking into account a typical number of start-up’s and shut-down’s”.

ENS (2015) states that is possible for a thermal power-plant to have its conversion efficiency slightly reduced over its lifetime, but the report does not take this factor under consideration. All the other studies assume a constant efficiency over the plant’s lifetime. This research follows the literature and does not consider this possible reduction in efficiency. ENS and Energinet (2016); Kost and Schlegl (2018) adopt a projection for this parameter and forecast that technological development will allow new future CCGT power-plants to be marginally more efficient.

The data points are close to of 60%. From the 13 points, 11 range from 59% to 62%, including the efficiency improvement for future plants. There are two outliers: the lower-end of the range observed in Agora Energiewende (2014) and the value stablished by EIA (2018a), both at 52%.

Based on the data, this study selects the value of 60% for this variable, instead of a distribution, given the convergence of the points around 60%.

5.1.5. CO_2 Emission Factor

Multiplying the CO_2 emission factor by the cost of an emission allowance, usually given in monetary unit over mass unit, it results in the emission cost of one energy unit of a fuel. To obtain the cost to generate 1 MWh of electricity with such fuel in a specific power-plant, it is necessary to further divide it by the plant’s energy conversion efficiency.

This research focuses on the emission costs actually incurred to CCGT plant operators, which relies on the emission allowance costs in the EU Emissions Trading System (EU ETS). The unit adopted for this parameter is the $tonCO_2/MWh_{therm}$.

The data points cluster around the value of 0,202 $tonCO_2/MWh_{therm}$. There is one outlier point, that is the value of 0,181 $tonCO_2/MWh_{therm}$ stablished by EIA (2018a), i.e. 10,4% lower. Observing the data, it is possible to choose one value for this variable, instead of a distribution. There is little variance concerning this and the other technical parameters. Given the convergence of the points around 0,202 tonCO2 / MWh_{therm}, this is the value to be considered for the carbon emission factor.

5.1.6. Construction Time

The data points fall into a narrow range of 2 - 2,5 years. It is possible to select one value for this variable, instead of a distribution. There is little variance concerning this and the other technical parameters. Given the concentration of the points, the value of 2 years is chosen for simplification purpose.

5.1.7. Investment Cost

Investment costs are often referred as capital expenditure (CAPEX), which has a broader definition as “the initial capital outlay for an investment project to generate future returns” (Konstantin & Konstantin, 2018b, p. 353). The investment cost is composed of the overnight costs and interest payments during construction (IDC), assuming that loans are needed when construction starts. The overnight construction costs refer to "i) direct construction costs plus pre-construction costs, such as site licensing, including the environmental testing; ii) the indirect costs such as engineering and administrative costs (…); iii) expenses (…) with the plant and plant site, but excluding off-site, 'beyond the busbar', transmission costs; and iv) contingency to account for changes in overnight cost during construction" (IEA & NEA, 2015, p. 31). Hence, overnight costs do not include interest charges (EIA, 2018a). To build a complete cost stream to calculate the LCOE, it is necessary to use the overnight cost as occurring in first year ($n = 0$) and consider the interest payments that occur in the construction time.

The data points converge well within a range between 700.000 and 900.000 EUR/MW$_i$. Two data points stand outside this range: 647.405 EUR/MW$_i$, at the lower bound of the range of Agora Energiewende (2014), and 1.045.627 EUR/MW$_i$, at the upper bound of the range of Kost and Schlegl (2018). Given the clustering, the value of 800.000 EUR/MW$_i$ is selected for the overnight cost.

There is more variance in this variable and the following financial parameters when compared to the technical parameters above. Yet, given that the focus of this research is to investigate the impact of the capacity factor on generation competitiveness, this study selects one value for this variable, instead of a distribution. The same approach is taken for the following financial parameters.

5.1.8. Fixed O&M costs

The fixed O&M costs are independent of the amount of generated energy by the plant. It includes "administration, operational staff, planned and unplanned maintenance, payments for O&M service agreements, network use of system charges, property tax, and insurance" (ENS, 2015, p. 14). It is usually given as an aggregate of all fixed costs in a currency unit per installed capacity, such as EUR/MW$_i$. In Equation (1), it is the variable $fixed\_O\&M_t$.

The data points mostly within the range of 20.000 and 30.000 EUR/MWi. There is one outlier: the data point of 9.834 EUR/MWi established by EIA (2018a). Given the distribution, the value 25.000 EUR/MW$_i$ is selected for the overnight cost.

5.1.9. Variable O&M costs

As defined, O&M costs are expenses during the operational period of a power-plant. In particular, variable O&M costs are those which depend on the generation output level of the plant. It includes "consumption of auxiliary materials (water, lubricants, fuel additives), treatment and disposal of residuals, output related repair and maintenance, and spare parts" (ENS, 2015, p. 14). It does not include fuel and emission costs. It is usually given as an aggregate of all variable costs in a currency unit per generated energy, such as EUR/MWh. In Equation (1), it is the variable $var\_O\&M_t$.

Agora Energiewende (2014) sets the variable O&M costs as zero, as it does so for the other analysed technologies (coal, wind and solar generation). The study presents no discussion to support this choice, although it distinguishes investment cost (labelled it Capital costs) from the others (that together are labelled Operating costs). Hence, the study has a different approach regarding O&M costs, and it does not use a data point for the variable on the same basis as the other studies.

The data points converge between the range of 3 and 5 EUR/MWh. If a narrower range between 4 and 4,54 EUR/MWh is considered, all but one data point is encompassed. The outlier is the data point of 3,13 EUR/MWh established by (EIA, 2018a), that refers to the US case. Given the clustering of the points around 4 EUR/MWh, this is the value to be considered for the overnight cost.

5.1.10. Decommissioning cost

The decommissioning cost refers to the costs of dismantling of the power-plant at the end of its lifetime and site restoration, as well as the possible revenues from iron scrap, left-over carbon permits, and others (IEA & NEA, 2015). For CCGT power-plants and other fossil-fuel technologies, it is usually the case that the decommissioning costs and revenues are similar, making it possible to assume a zero net decommissioning cost (ENS, 2015; IEA & NEA, 2015). Furthermore, any eventual non-zero result, positive or negative, would become considerably small in the LCOE method, since this cash flow occur at the end of the plant's lifetime and is discounted over a long period (IEA & NEA, 2015).

The examined datasets do not use a value for decommissioning costs. The only exception is IEA and NEA (2015): although it reports a general assumption of zero for thermal power-plants and of 5% of the overnight cost for other technologies, the survey respondents had the option to report a different value. For CCGT generation in Germany, the reported levelized decommissioning costs were of 0,08, 0,04, and 0,01 EUR_{2017} / MWh, when using a discount rate of 3%, 7%, and 10%, respectively. These values represent a share of the reported total LCOE for CCGT generation of 0,1%, 0,05%, and 0,02%, respectively. So, considering the results are considerably low, that the examined studies do not establish a value for the parameter, and that normally the costs are offset by the revenues, this variable is set to zero in this research project.

5.1.11. Discount Rate

Zweifel et al. (2017) argue that the value of the discount rate can greatly impact the result of the investment appraisal. The concept of interest rate refers to the cost of capital. It "determines the minimum acceptable discount rate of an investment project". To avoid the need to forecast inflation rates, it is possible to use real values for all costs and the discount rate in real terms (Konstantin & Konstantin, 2018a, p. 37; Kost & Schlegl, 2018). In Equation (1), the discount rate is denoted as i and is used in real terms.

The data points range from 3% to 12%. As IEA and NEA (2015) and ENS (2015) explicitly state that their values of 3% and 4%, respectively, correspond to social costs of capital, it is possible to infer that they are not appropriate for a private firm's choice of discount rate. IEA and NEA (2015) further reports the values of 7% that reflect conditions on deregulated markets, and of 10% that reflects a high-risk environment – it is argued that both are applied to all technologies and regions to allow cost comparison. Agora Energiewende (2014) and EIA (2018b) do not present a discussion to support their choice.

Two of the data sources present a more specific approach to the CCGT technology and for the case of Germany. Kost and Schlegl (2018) and Konstantin and Konstantin (2018b) calculate the Weighted Average Cost of Capital (WACC) for each technology considering their project-specific risk, so, the values assumed by the studies are specific for the case of a CCGT power-plant in Germany. The WACC is calculated considering the composition of the firms financing for the project, i.e. the share of corresponding to the interest rate on debt and the share corresponding to the desired return on equity (Konstantin & Konstantin, 2018a).

The choice of the interest rate value has to consider that, for the objectives of this research, the LCOE of CCGT generation is investigated and compared to storage costs. Hence, the selected value for interest rate has to be common for all examined technologies. Additionally, one of the research motivations is the concern of diminished profitability due to expected lower capacity factor and, so, this is the main variable under scrutiny. Despite the fact that the interest rate variable is relevant in the LCOE calculation, the focus is in allowing cost-competitiveness comparison. Therefore, the value to be used on the LCOE calculation is the one stablished by IEA at 7%, which reflect market conditions.

The economic parameters display a larger variance compared to the technical and financial ones. Yet, given the focus of this research to investigate the impact of the capacity factor on generation competitiveness, this study selects one value for the discount rate variable instead of a distribution.

5.1.12. Fuel cost

Fuel cost is determined by the natural gas price and the power-plant efficiency. It is a type of variable cost, as it depends on the output level of the plant (Konstantin & Konstantin, 2018b). The fuel transport cost is considered as well, so as to establish the total fuel cost for the plant's operator, although it is significantly small for large-scale power-plants. It is important to point out that fuel prices vary across regions (ENS, 2015). As the calorific value of gas also varies across regions, the unit expressed in EUR/MMBtu provides a more unambiguous basis for comparison. So, this research adopts the unit of EUR_{2017}/MWh_{therm} to express fuel and other costs that depend on fuel.

Fuel cost is the variable $Fuel_t$ in Equation (1), and is expressed in its final value for the electricity generated, i.e. the sum of natural gas and transport costs divided by the efficiency. The data collection of this section focuses on natural gas prices, as data for conversion efficiency is covered above.

Data on natural gas prices are given mostly in time-series, different from the previous variables. The exception is the IEA and NEA (2015, p. 32), that reports one value for the operational lifetime: 28 EUR/MWh_{therm}. The authors argument that it is the "average OECD import price assumptions for (…) natural gas provided by the IEA Office of the Chief Economist". More specifically for the case of Germany, the value of 33 EUR/MWh_{therm} was inferred, which corresponds to the data collected by the authors with the German national government. The latter data point is more in line with the price development established by the other data sources.

The other three data sources assume the gas price for 2018 ranging from 21 to 25,7 EUR/MWh_{therm}. Price is forecasted to rise significantly, reaching values between 30,8 to 35,5 EUR/MWh_{therm} in 2030, meaning the average value would increase 31%. From there on, prices are projected to increase more gradually in three scenarios or, for one scenario, to decrease. The two scenarios from ENS (2015) Current Policies and New Policy, and the scenario reported by Kost and Schlegl (2018) converge well from 2018 to 2035.

The New Policy scenario and the 450ppm scenario provide useful projections on fuel and emission costs. The former considers a rising tendency for natural gas prices and moderate growth for prices of emission rights. Conversely, the latter considers a future where more policies will be in place to tackle climate change and, thus, the emission right prices are forecasted to rise more steeply. The natural gas prices in the 450ppm scenario are the lowest among the data sources, likely due to lower demand on the fuel. These scenarios presented in (ENS, 2015) are a result of the model from (IEA, 2015), and reflect the impact that energy policies have on the two variables. The forecast on fuel and emission prices present a consistent trade-off, useful for the research on CCGT generation costs. So, values from both New Policy and 450ppm scenarios are selected for the LCOE calculation.

5.1.13. Emission cost

The emission cost for the LCOE calculation reflect the costs incurred to the plant operator for the purchase of emission allowances on a CO_2 market. So, they are determined by the CO_2 emission allowance price, the CO_2 emission factor of natural gas and the power-plant efficiency. It is a type of variable cost, as it depends on the output level of the plant (Konstantin & Konstantin, 2018b). The emission allowance price in the EU emission trading system (EU-ETS) has the purpose to reflect the external cost caused by CO_2 emission but fails to do so because prices have been too low and too volatile since its implementation. Hence, the cost with emission rights reflect a cost the electricity producers incur but not the internalization of GHG social costs (ENS, 2015; Zweifel et al., 2017).

Emission right prices are given in EUR_{2017}/MWh_{therm}, using the carbon emission factor of natural gas. The value is a representation of the cost to obtain the emission allowance for one unit of energy of natural gas. Later, it is divided by the power-plant efficiency to obtain the cost of emission rights to generate one unit of electrical energy, i.e. 1 MWh.

Data on emission right prices are given mostly in time-series, similarly to gas price data. IEA assumes one value for the operational lifetime though: the value of 3,9 EUR/MWh_{therm} is the generic assumption for all countries without specific available data, while the 4,4 EUR/MWh_{therm} value was inferred as the data collected by the institutes with the German national government.

The other three data sources report the emission right price for 2018 ranging from 1,06 to 3,3 EUR/MWh_{therm}. Similar to natural gas, emission right prices are forecasted to rise significantly, reaching values between 5,0 to 17,1 EUR/MWh_{therm} in 2035, meaning the average value would increase 318%. All scenarios converge well until 2022. Two scenarios from IEA, Current Policies and New Policy, and the lower scenario established by Kost and Schlegl (2018) fall into a narrow range from 2022 to 2035. Similarly, the 450ppm scenario and the upper scenario from the latter author are similar during the same period.

Following the debate presented for the data selection for fuel costs, the scenarios New Policy and 450ppm from IEA are selected for the emission right costs variable. They represent values that the market price for CO_2 could assume. They do not, however, represent an attempt to reflect the costs imposed to society caused by GHG emissions.

5.2. Uncertainty Range of the Capacity Factor

This section presents the uncertainty range of the capacity factor variable for CCGT generation during the energy transition in Germany. Based on the discussion presents in Section 5.1.1, I select the data points found in the literature that are compatible with this research and determine the uncertainty range, in order to answer the research sub-question I.

The examined literature does not present convergence on the forecast of capacity factor for CCGT generation for the next decades, i.e. or for the lifetime of a new power-plant for which the investment decision is presently being made. Similarly, it was not found in the literature any debate of probability distribution for the variable, feasibility of scenarios or ranking of likelihood.

Uncertainty can be defined as “a situation of inadequate information, which can be of three sorts: inexactness, unreliability, and border with ignorance” (Funtowicz and Ravetz, 1990, as cited in Walker, Marchau, & Kwakkel, 2013, p. 220). For policy analysis, Quade, 1989 as cited in Walker et al. (2013) defines the term real uncertainty, that relates to the relation that a future state of a variable in a system is a result of actors’ strategic behaviour. These definitions relate strongly to the discussion in this section, as the utilization rate of CCGT power-plants will be largely influenced by the actors in the power sector and their decisions regarding level of investment in RES, level of investment in conventional plants, lobbying forces and regulatory interferences. Ventosa et al. (2013) argue that decisions in oligopolistic electricity markets are strongly characterized by strategic interdependence among actors.

Walker et al. (2013) categorizes uncertainty in policy making processes under different levels and location in the system. The authors define five levels and four locations of uncertainty. Considering the collected data in Section 4.2 and present discussion, the variable capacity factor for CCGT generation in Germany falls under the Level 4 of uncertainty and the location is about the system response to the external factors and/or policy changes. These are briefly explained below.

Walker et al. (2013, p. 229) define five levels of uncertainty. Additionally, the authors define Complete Certainty and Total Ignorance as the extreme cases and boundaries for the five cases. The Level 4 of uncertainty is defined as representing “the situation in which one is able to enumerate multiple plausible alternatives without being able to rank the alternatives in terms of perceived likelihood. This inability can be due to a lack of knowledge or data about the mechanism or functional relationships being studied; but this inability can also arise due to the fact that the decision-makers cannot agree on the rankings”. Considering that the reviewed literature does not converge on a value or distribution probability, this definition suits well the variable in question.

The same authors also define four possible locations of uncertainty. One of them is about the system response to policy changes and/or external factors. It refers to a model structure uncertainty, which "arises from a lack of sufficient understanding of the system (past, present, or future) that is the subject of the policy analysis, including the behaviour of the system and the interrelationships among its elements" (page 226). As presented in Section 2, the literature suggests that high share of RES causes structural changes in the merit of order, reducing the utilization rate of conventional power-plants. The increasing presence of RES is largely due to policy interventions in the form of support schemes. Hence, the location of system response to policies is adequate to the capacity factor variable.

Therefore, it is possible to affirm that the capacity factor variable for CCGT generation is under uncertainty. So, in order to define the uncertainty range, the identified data is not assigned a probability and the dataset is considered to have a uniform probability distribution. Therefore, the answer for the sub-question I: *What is the expected capacity factor for CCGT generation in Germany during the energy transition?*, is the determined range from 21% to 57%. The results are presented in Table 12. The data points are defined for a new power-plant starting operation in the specified year and given as one value for the lifetime of the project, except for the data from Kost and Schlegl (2018), that is determine for each operational year.

Table 12. CCGT generation capacity factor, in %.

	(IEA & NEA, 2015)	(Kost & Schlegl, 2018)*	(ENS & Energinet, 2016)	(Agora Energiewende, 2014)	(Konstantin & Konstantin, 2018b)
2013	50%			22,8% | 45,7%	
2015			57%		
2017					55,4%
2018		23% | 40% | 57%			
2020		23% | 39% | 57%			
2025		22% | 38% | 55%			
2030		21% | 37% | 54%			
2035		21% | 35% | 52%			

* Data points established for each operational year.

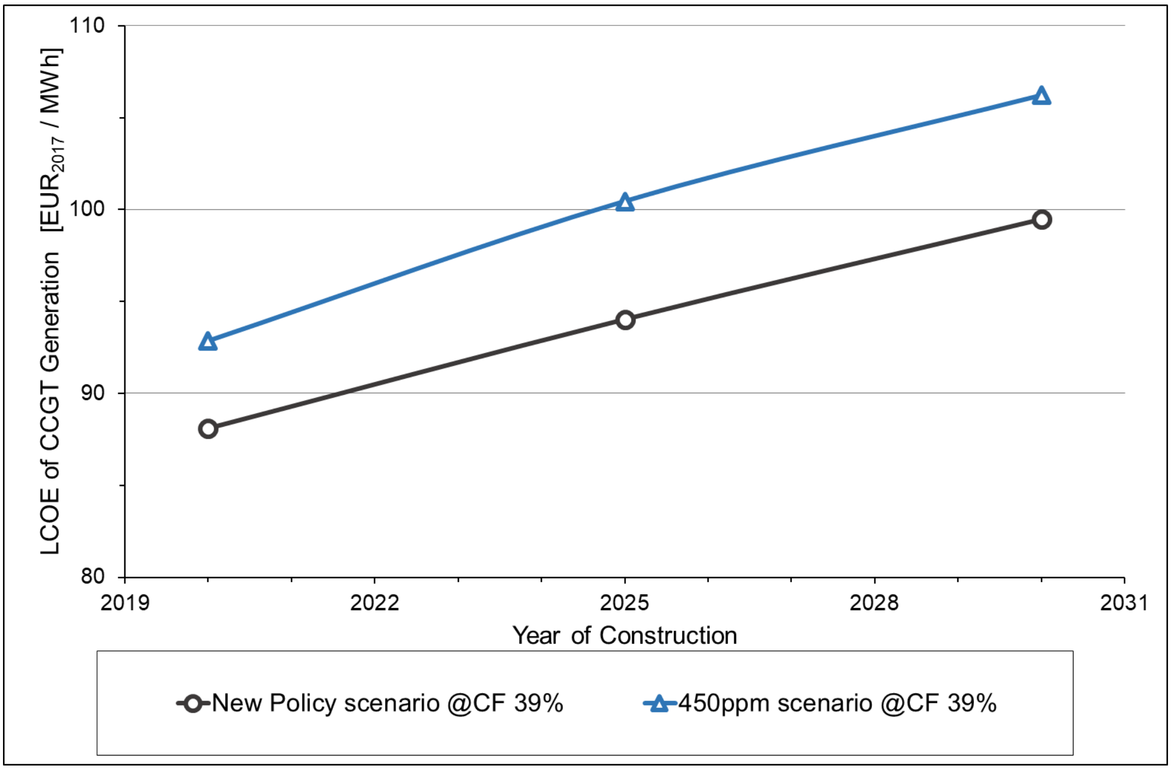
Two data points are not considered for the uncertainty range in this research. This research does not use value of 85% reported by IEA & NEA and the value of 87% assumed by EIA as they are incompatible with the CCGT technology under the assumptions for this research. The former relates to a capacity factor of plants serving the base-load, and the authors recognize the value is too high for natural gas units. The latter represents the high end of the technology's likely utilization range, which also is for a plant that serves the base-load. Given that this research investigates CCGT as an option for system flexibility and peak-serving, and the assumption that its utilization is likely to reduce over time, the two values are excluded.

5.3. LCOE Calculation

This section presents the calculation of the LCOE for CCGT generation for new power-plants entering operation in 2020, 2025 and 2030. These results contribute to a more profound understanding of the competitiveness of CCGT generation and are the first step to answer the research sub-question II. The cost evolution in the ten years interval is useful for comparison with technologies in evolutionary state and whose costs are expected to reduce (e.g. VRFB).

The LCOE is calculated using the selected values for each variable that best correspond with the assumptions and objectives of this research, as presented in sections 5.1 and 5.2. I apply them to Equations (1) and (2). The input variables that are forecasted to change significantly in the analysed period are the fuel and emission costs. A spreadsheet model was used to construct two scenarios, based on the fuel and emission costs defined in the New Policy and the 450ppm scenarios from IEA.

Considering that the capacity factor variable is under uncertainty, the median point is selected as a reference case for the LCOE calculation, i.e. 39%. Later in Section 5.4, the entire range, i.e. 21% to 57%, is contemplated to investigate the impact on the levelized cost. The results are presented in Graph 1.



Graph 1. Results on LCOE of CCGT generation at a capacity factor of 39%, in EUR_{2017}/MWh.

The results show that the stricter policies to curb climate change under the 450ppm scenario are expected to increase generation costs in 4,8, 6,4 and 6,7 EUR/MWh for plants entering operation in 2020, 2025 and 2030, respectively. The main reason for a higher LCOE under the 450ppm scenario is the emission rights cost. Although the natural gas price is forecasted to be lower, the steep increase in CO_2 prices is quantitatively more important.

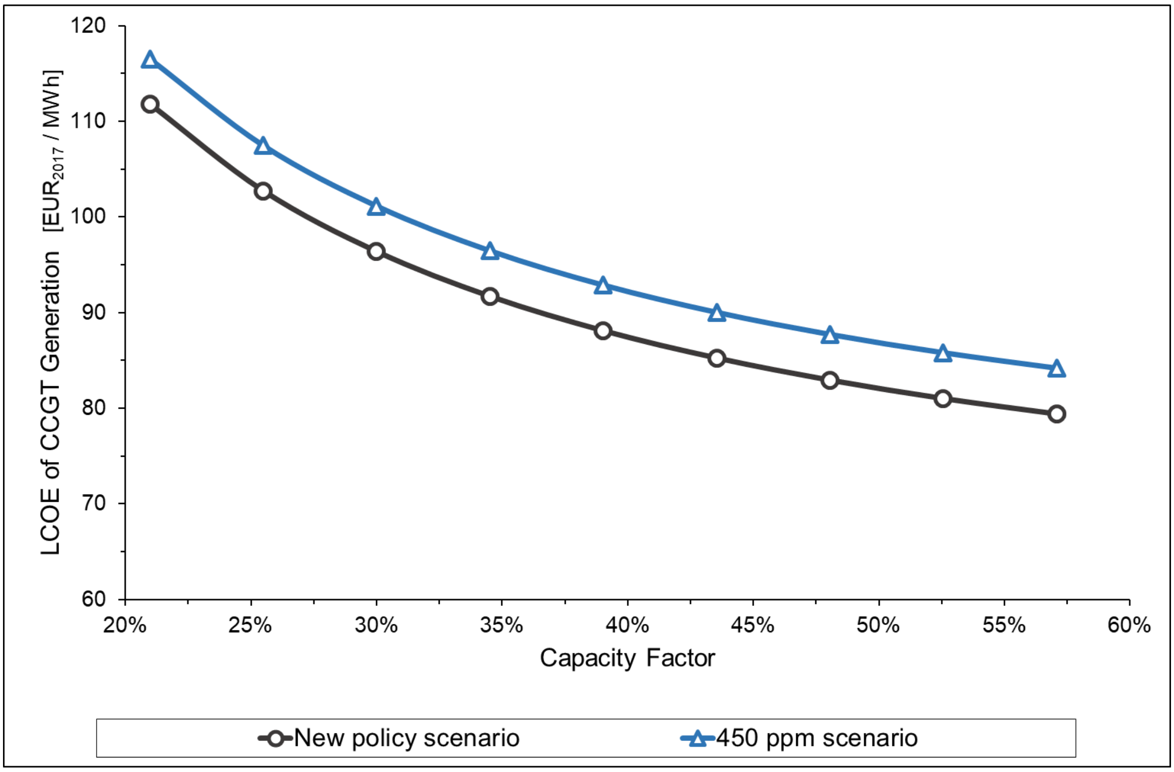
The results also show that the LCOE for new CCGT power-plants is expected to increase over time. The rise is of 11,4 EUR/MWh in the New Policy scenario and of 13,4 in the 450ppm scenario. So, more strict policies are expected to cause CCGT generation to be increasingly less competitive.

5.4. Sensitivity Analysis

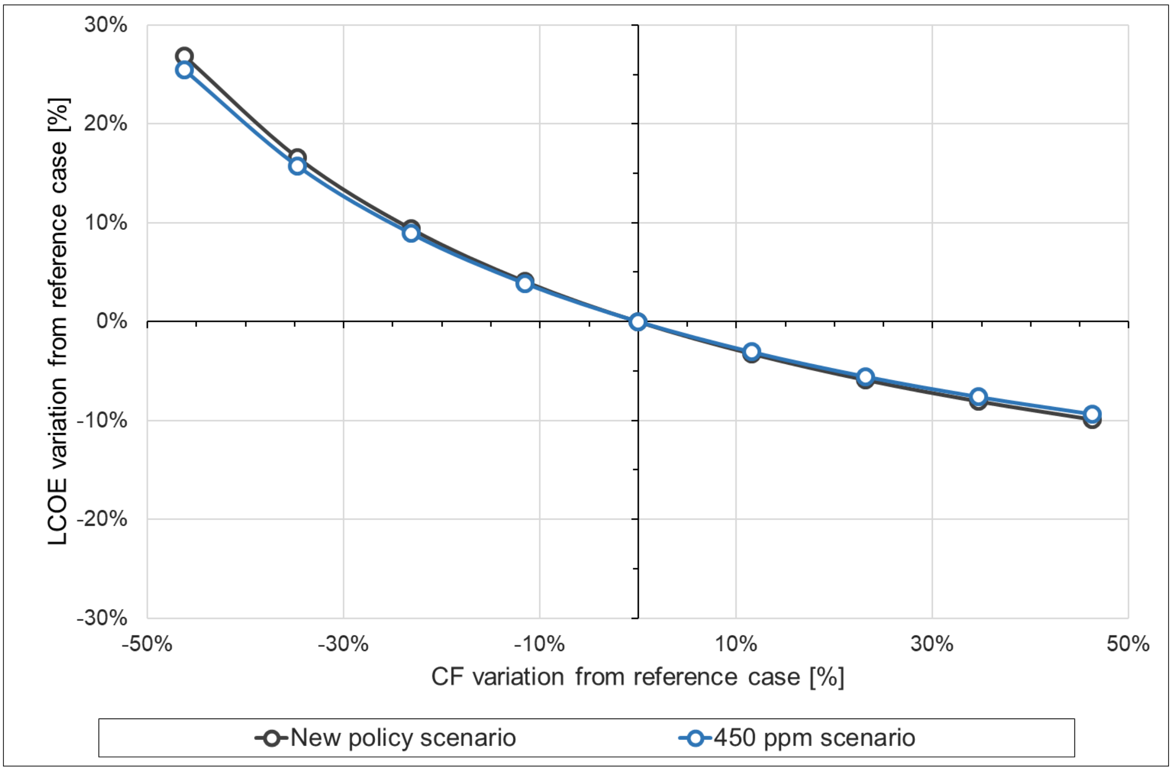
This section presents a sensitivity analysis to examine the effects of the capacity factor uncertainty on the LCOE of CCGT generation. The results extend the previous LCOE analysis and help answering the research sub-question II.

First, I present the LCOE of a new plant entering operation in 2020 given for several values of capacity factor. Stretching from the lowest to the highest end of the uncertainty range, nine values were selected uniformly distributed. This allows for a more detailed sensitivity analysis. Secondly, I present the time-series results for plants entering operation in 2020, 2025 and 2030.

Graph 2 illustrates the results for new CCGT power-plant commencing operation in 2020. The results show the generation costs for both the New Policy and the 450ppm scenarios. It is possible to observe that the LCOE is sensitive to the capacity factor level, as expected. In both scenarios, the difference from the highest to the lowest result (i.e. from the lowest to the highest utilization rate) is 32,4 EUR/MWh. This represents a difference of +41% under the New Policy scenario and of +38% under the 450ppm scenario. The levelized cost is more sensitive, relative to the reference middle-point, to lower values of capacity factor. Lower utilization levels deter the capacity to recover investment and fixed operation costs. The sensitivity analysis in relative terms from the reference case is presented in Graph 3.

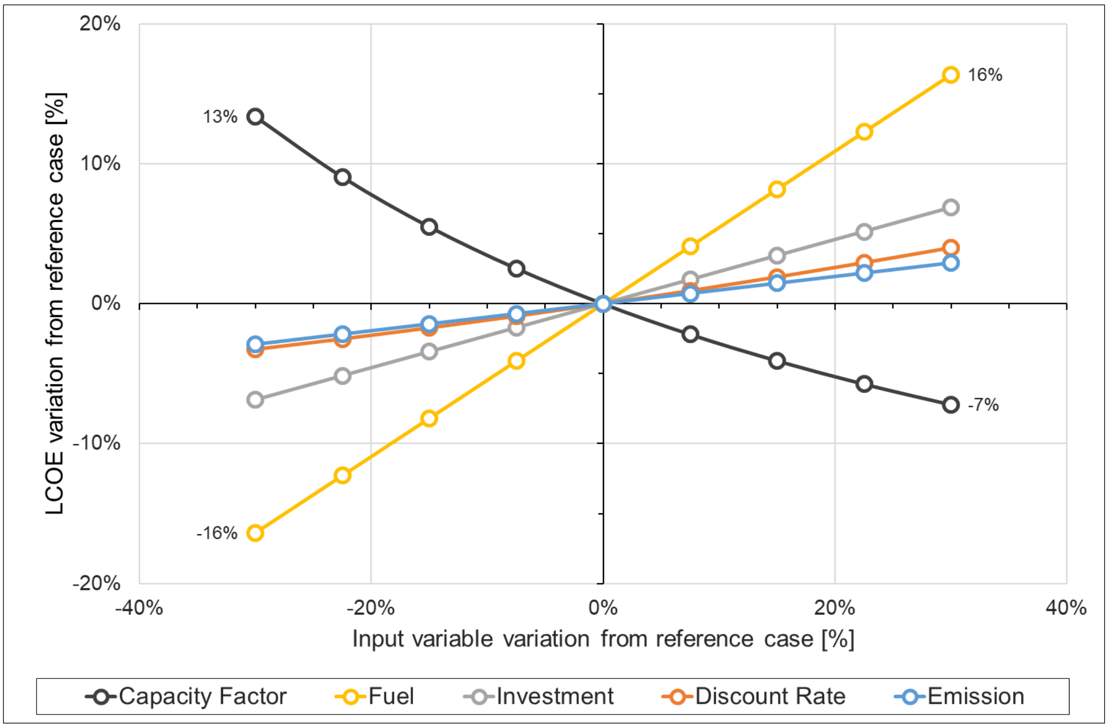


Graph 2. Results on the LCOE for a CCGT power-plant entering operation in 2020, in EUR_{2017}/MWh.

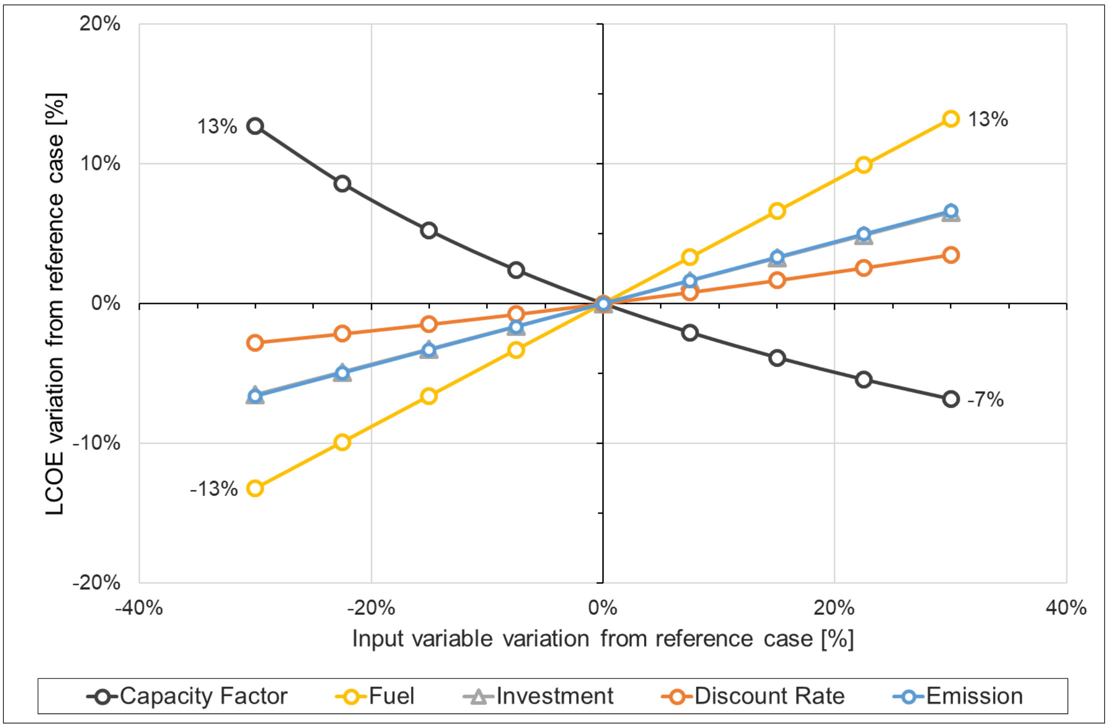


Graph 3. Results on the sensitivity analysis of the LCOE for a CCGT power-plant entering operation in 2020.

The results have shown that the LCOE is dependent on the capacity factor, but the sensitivity analysis to other cost components give a comparison basis to determine the relative importance of the variable. This examination is expected to provide insight both for policy interventions and for the investor`s perspective towards CCGT investment. Graph 4 and Graph 5 show the sensitivity analysis of LCOE to fuel, investment, and emission costs, the discount rate, as well as the capacity factor. The New Policy and the 450ppm scenarios are considered. For this analysis, the variables were varied from -30% to +30% relative to their reference cases.



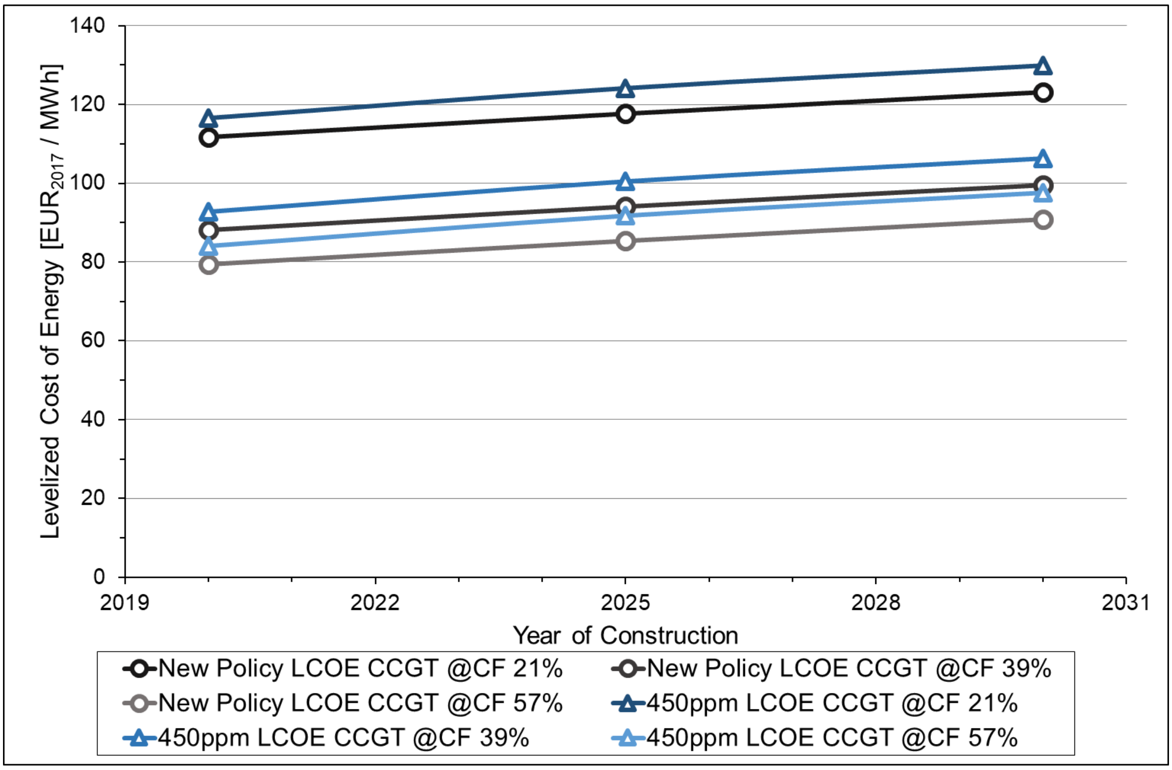
Graph 4. Sensitivity analysis of selected variables of CCGT LCOE - New Policy scenario.



Graph 5. Sensitivity analysis of selected variables of CCGT LCOE - 450ppm scenario.

The results show that the LCOE is most impacted by fuel costs. Moreover, the sensitivity relation of LCOE to fuel costs dominates the relation to capacity factor in both scenarios. The changes caused by the two variables are similar when the lower utilization rates are observed. However, the change caused by fuel costs is more relevant for higher utilization rates. Capacity factor is more relevant than the other examined variables and dominates the sensitivity relations to discount rate, and investment and emission costs.

Finally, the time-series results are presented in Graph 6 for three levels of capacity factor (21%, 39% and 57%) and for the New Policy and 450ppm scenarios.



Graph 6. LCOE results for CCGT plants entering operation in 2020, 2025, and 2030, for the high and low end of the capacity factor range. In EUR_{2017}/MWh.

The results show that the LCOE increases over time in similar manner for the three values of capacity factor. This is explained by the fact that the only variable expected to change significantly over the period are fuel and emission costs, which are variable costs.

Additionally, the capacity factor uncertainty is expected to sustain the inexactness about CCGT competitiveness in the future. These results are illustrated by following findings:

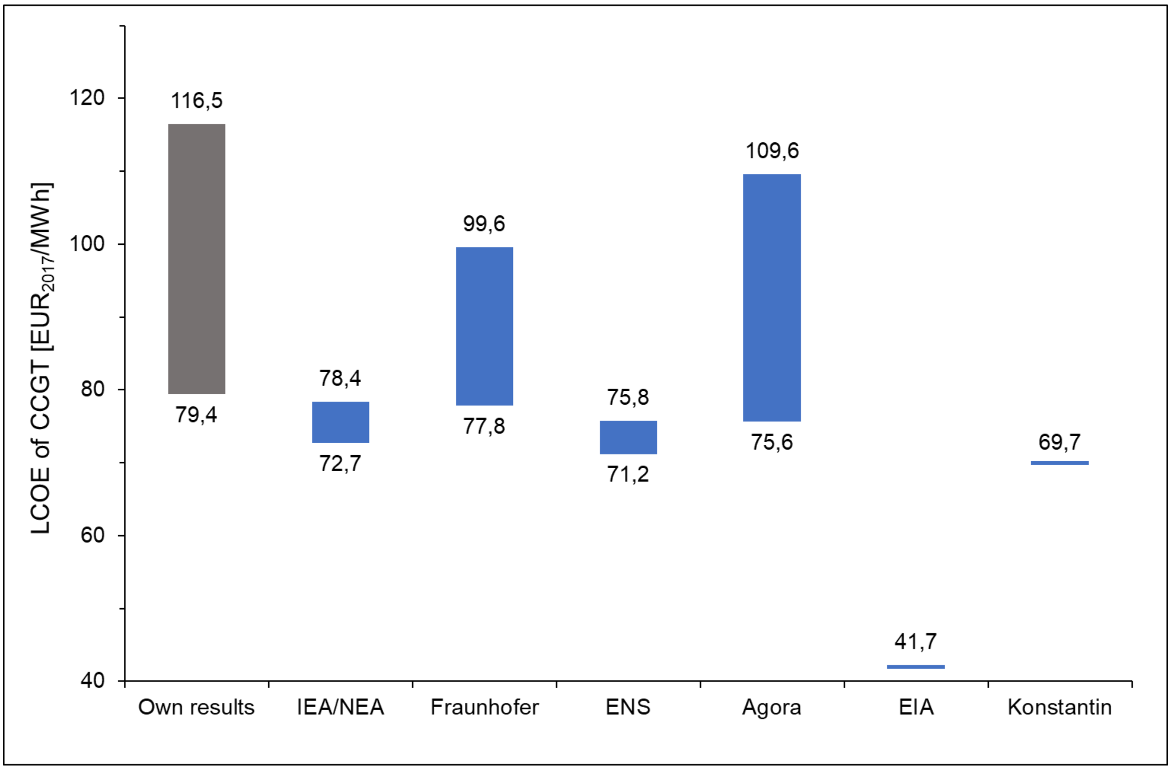
- For all capacity factor considered and both scenarios, the levelized cost increases in similar manner: in the New Policy scenario, the raise is of 11,4 EUR/MWh; in the 450ppm scenario, the increase is of 13,4 EUR/MWh. This represents increases between 10% and 16% from 2020 to 2030.
- It is important to also point out the range between the extreme cases: the difference from the upper bound, set by the LCOE at a capacity factor of 21% in the 450ppm scenario, to the lower bound, set by utilization rate of 57% in the New Policy scenario, is of 37, 39, and 39 EUR/MWh in 2020, 2025 and 2030, respectively.

Therefore, the research sub-question II: *'From the perspective of a single firm, how does the reduced capacity factor* for CCGT generation in Germany affect its competitiveness in terms of generation costs?*'* can encompass three dimensions. The first is that the capacity factor uncertainty causes the LCOE forecast to be inexact, ranging by almost 40 EUR/MWh. The second is that the cost increase over time reflects worst conditions of natural gas and emission costs. The third dimension is that the cost difference from the two scenarios reflects regulatory uncertainty. These results evidence the concern over the competitiveness of CCGT power-plants, and that policy-making for the power sector ought to consider and focus on these dimensions.

5.4.1. Results Comparison with Other Studies

The results obtained in this research for LCOE of CCGT generation are compared with those reported in the examined literature. The objective is put the results of this section into perspective and to assess how they differ from other studies that use different assumptions. The examined studies have various goals for calculating LCOE and, so, the underlying financial and economic assumptions are often not in line with the scenario of the problem in hand.

The LCOE results from the six examined studies are presented in Graph 7 along with the results of this research. The comparison shows that this research proposes levelized costs for CCGT generation that are more uncertain and generally higher than those encountered in the literature.



Graph 7. Comparison of own LCOE results with examined literature, in EUR_{2017}/MWh.

To help understand the differences, it is useful to analyse the objectives and assumptions of each study. Table 13 summarizes this information, displaying the capacity factor assumption, the variable that is the focus of this research, and the other most relevant assumption differences. The region/country where the plant is to be constructed and the year of operation start are also presented, for the reason that awareness of the spatial and temporal differences is important for the comparison of different studies.

Table 13. Comparison of research objective and assumptions for LCOE calculation.

Research	Research objective	Region and operation start	Capacity factor assumption	Other assumption differences[1]
Own research	CCGT competitiveness under increasing presence of RES.	Germany, 2020[2].	21% - 57%	-
IEA/NEA	Cost comparison across regions and technologies.	Germany[3], 2015.	85%	Results range due to the use of three discount rate values: 3%, 7% and 10%. Emission costs are 14% lower.
Fraunhofer	Cost comparison across technologies in Germany.	Germany, 2018.	27% - 46%	Emission cost is 40% to 70% lower[4]. Discount rate of 5,2%.
ENS	Social cost analysis across technologies.	Europe (focus on Denmark and Germany), 2016.	57%	4% social discount rate.
Agora	Cost comparison across technologies in Germany.	Germany, 2015.	23% - 46%	Discount rate between 6% and 12%.
EIA	Cost comparison across technologies and states in the USA.	USA, 2020.	87%	Discount rate between 3,7% and 4,5%. Fixed and variable O&M are 60% and 22% lower.
Konstantin	Cost comparison across technologies in Germany.	Germany, 2016.	55%	Lifetime of 25 years.

[1] Comparison is presented as the difference from the examined study in relation to the assumptions made in this research.
[2] LCOE are also calculated for plants entering operation in 2025 and 2030, but not used in this comparison.
[3] IEA calculates LCOE for several countries, but this research collected data for the German case only.
[4] Comparison between the lower bound values of each studies.

The study from Agora presents a range of results that is similar in extent to the one in this research: the difference between upper and lower bound is 34 EUR/MWh for the former and 37,1 EUR/MWh for the latter. IEA, Fraunhofer, and ENS also propose LCOE ranges, that are of 5,7, 21,8, and 4,6 EUR/MWh respectively. The other studies provide a single value as result. Moreover, the entire range of LCOE calculated in this research is higher than the values proposed by four of the examined studies: IEA, ENS, EIA and Konstantin.

The difference observed in the results from this research to one of the others is caused by combination of variables with particular assumptions. For instance, this research and the studies from Fraunhofer and Agora have relatively small differences on the capacity factor assumptions and, yet, the LCOE results are more divergent. So, the difference is further explained by the assumptions on discount rate and emission costs. Another example is the levelized cost proposed by EIA, which is 47% smaller than the lower bound calculated in this research. The variation is due to three variables: discount rate, fixed and variable O&M.

Despite the differences identified above, the results of this research are in line with the results of the examined studies. The range of results is larger due to a more exhaustive scrutiny of the capacity factor uncertainty. They are also higher than most LCOE values encountered in the literature due to a combination of different assumptions, especially on discount rate, emission and O&M costs. The exception is the study by EIA, which presents a levelized cost significantly smaller. Being the only study focused on the USA and the several distinct assumptions observed help to clarify this deviation. Notably, these studies` objectives are relevant in determining the set of assumptions and, hence, the LCOE results.

5.5. Energy Storage

This section presents a discussion on the collected data for ES costs. The service of energy shifting is considered, as it reflects the long-term bulk energy management. Data on energy storage costs is used in this research for comparison purposes with CCGT generation costs. This cost comparison is expected to provide insights for energy policy and choice of flexibility sources. IRENA (2017) argues that energy storage is an important drive for energy transition, as it can offer the necessary flexibility to allow high shares of RES in power systems. The ES technologies that can offer flexibility similarly as CCGT generation are CAES, PHS and VRFB, as identified in Section 2.1.8.

The calculation performed by IRENA for energy shifting uses the following set of values for all technologies: installed power capacity at 1.060 MW; energy-to-power rate at 8,02; and cycles per day at 0,8. This research modifies the interest rate to match the value used for the LCOE of CCGT, i.e. 7% in real terms. The LCOES is calculated for new units entering operation in 2016, 2020, 2025, and 2030, allowing to observe future cost development. The best, reference, and worst cases are considered, in order to observe the cost uncertainty of each source.

From Table 7, it is possible to observe that both CAES and PHS are mature technologies and that no major improvements nor costs reduction are expected for them. Another important characteristic is that both are very-site specific for depending on natural structures to be implemented, such as rivers and caverns. Uneven distribution of suitable locations across regions and environmental concerns are limiting factors (ENS, 2012; IRENA, 2017). Hence, despite being technically mature and suitable to provide system flexibility in a long-term basis, they have limited availability. Regarding their technology learning curve, Table 14 presents the expected parameters of CAES that are expected to evolve until 2030 according to IRENA (2017). There are no developments expected for the PHS.

Table 14. Current and expected values of CAES parameters expected to evolve.

	Energy installation cost [EUR/MWh]			Round-trip efficiency [%]		
Case	*Best*	*Refer.*	*Worst*	*Best*	*Refer.*	*Worst*
2016	1.855	49.148	77.894	75	60	40
2030	1.576	40.802	65.839	85	68	45
Δ	*-16%*			*13%*		

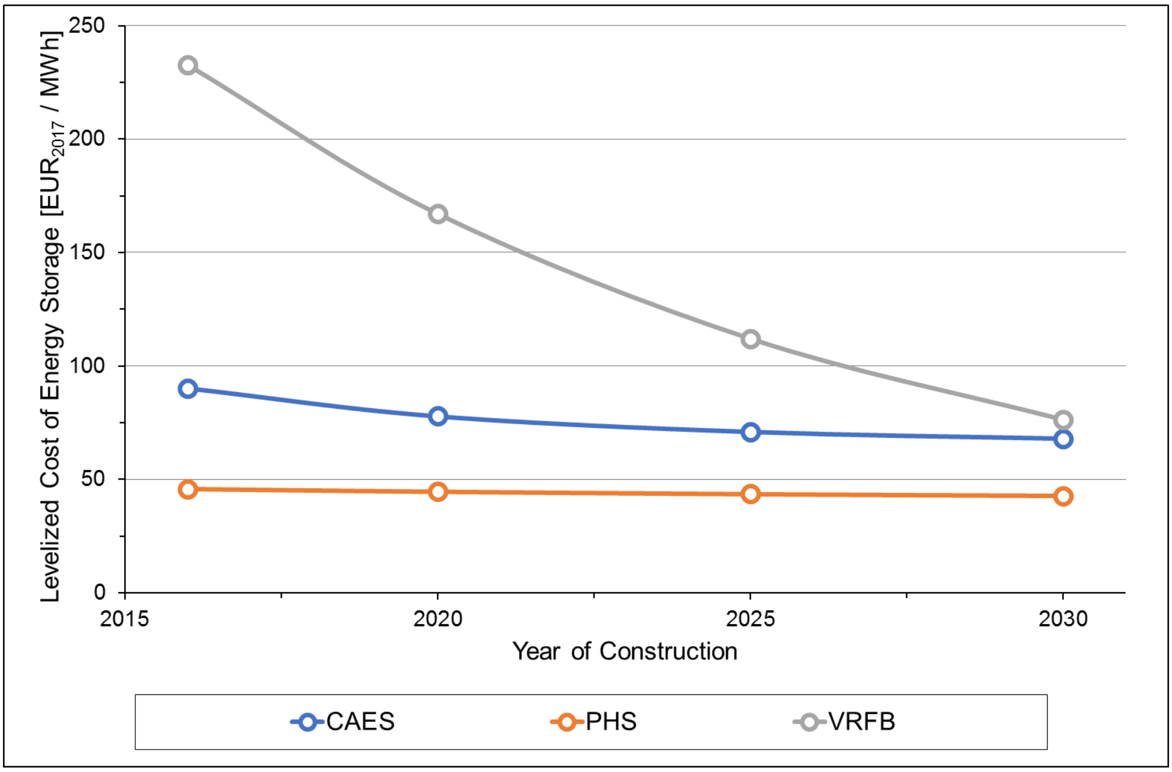
Conversely, the VRFB technology is expected to evolve significantly until 2030, leading to reduced costs. Consequently, it will become an option to provide long-term bulk energy management (ENS, 2012; IRENA, 2017). Regarding its learning curve, Table 15 presents the expected parameters of VRFB expected to evolve until 2030 according IRENA.

Table 15. Current and expected values of key VRFB parameters expected to evolve.

	Energy installation cost [thousand EUR/MWh]			Calendar life [years]			Round-trip efficiency [%]		
Case	*Best*	*Refer.*	*Worst*	*Best*	*Refer.*	*Worst*	*Best*	*Refer.*	*Worst*
2016	292,1	321,8	973,7	20	12	5	85	70	60
2030	100,1	110,4	333,8	32	19	8	95	78	67
Δ	*-66%*			*60%*			*12%*		

One relevant point for this research is that IRENA does not include the cost incurred to obtain the necessary electricity to charge the ES. In order to reflect the activity of energy shifting, this research considers that the ESS operator charges at moments of larger generation availability and/or lower demand, so to provide energy in moments of supply scarcity. So, this research adds the cost incurred to obtain electricity in the wholesale market to the LCOES proposed by IRENA. The average price of baseload hours is used as the electricity price incurred to ESS. Considering the period from 2006 until July-2018, the average baseload price is 35,40 EUR/MWh.

In summary, on one hand CAES and PHS are the ES technologies currently more competitive for the energy shifting service, however hindered by site-restrictions. As mature technologies, their costs are likely to remain stable. On the other hand, VRFB is currently less cost-competitive but, as a technology in an evolutionary state, its costs are expected to fall significantly and to become cost-competitive with the former two by 2030. One advantage of VRFB is that it is not restricted to specific sites and, so, it can be scaled to provide system flexibility. Graph 8 shows the current and expected future LCOES for the three types of ESS in their reference cases, in order to illustrate the cost comparison.



Graph 8. LCOES projection of CAES, PHS and VRFB. Reference cases in EUR_{2017}/MWh.

5.6. External Costs

This section presents the results for efficiently set external costs of CCGT generation and ESS. In order to completely incorporate externalities into the policy analysis for the power sector, the results are transformed to the same unit of electricity prices, i.e. EUR/MWh, so it can be compered and added to LCOE values. A discussion on the collected data is also presented. In this way, it is possible to answer the research sub-question III. The collected data is presented in Section 4.5.

This research considers three scenarios of climate change costs and CO_2 cost rate. The first two are the New Policy and the 450ppm scenarios, proposed by IEA, and reflect market costs of CO_2. They are used in the previous sections for LCOE calculation and do not have the intention to internalize entirely the societal costs of GHG into electricity prices. Conversely, the third scenario is the one proposed by UBA and follows a methodology that actually seeks to measure societal costs from GHG emission. It is not, however, a cost incurred to plant operators.

Therefore, the calculation of LCOE from the previous sections only partially internalizes climate change costs and establish generation costs perceived from generation firm actors. In order to account for this fact, I use the values proposed by UBA and add them to the LCOE results. The outcome is the cost of generation as perceived by society.

5.6.1. Cost Rate of CO_2 and Air Pollutants

The cost rate of CO_2 can be estimated by two methods: the damage cost and the avoidance cost. The former provides an indication of the damages caused by CO_2 emission and a monetary valuation, considering assumptions on social discount rate and equity weighting – it is also known as the social cost of carbon. The latter reflects the opportunity cost to change *status quo* so that GHG emissions fall under a socially acceptable level (ENS, 2015; UBA, 2012). In either case, the direct and indirect emissions should be considered, i.e. the emissions due to fuel combustion in the power-plant to generate electricity throughout its operational lifetime, and the emissions caused by its installation and decommissioning (UBA, 2012).

UBA explicitly uses the damage cost method and presents a discussion about the two methods to sustain its option. Although the avoidance cost method provides a good indication on expanses to adapt the infrastructure, it does not measure the effective impact climate change has on society. The agency argues that the damage cost method is therefore more appropriate.

To put the UBA method in perspective, the method used by IEA is discussed here. IEA defines values per region to reflect "the extent of policy interventions to curb growth in CO_2 emissions". Although there is no clear definition if prices follow a damage or avoidance cost method, it is possible to infer that IEA applies the latter, as it reflects the necessary policy intervention to achieve a certain target. Also, it is possible to infer it considers the direct costs only.

Regarding air pollution, the cost rates follow the premise to estimate environmental and health costs due to gas and particles pollutants. Although the impacts of pollutants are site specific due the fact that emissions closer to highly populated areas cause more damage, it is possible to define one average value for a country. The literature indicates the most relevant pollutants are sulphur dioxide (SO_2), nitrogen oxides (NO_X) and particles smaller than 25 microns ($PM_{2,5}$) (ENS, 2015; UBA, 2012).

5.6.2. Societal Cost of CCGT Generation

The collected data on the external costs of CCGT generation is presented in Table 10. It is possible to observe that the values reported by the two sources are significantly different. For climate change costs, UBA calculates the value of 40,9 EUR_{2017}/MWh, which is 122% higher than the value of 18,4 EUR_{2017}/MWh by ENS. For air pollution costs, the values calculated are 10,7 and 2,0 EUR_{2017}/MWh respectively, a difference of 434%. The total external costs are 51,5 and 20,4 EUR_{2017}/MWh.

One reason for the observed difference is the divergent cost rates of CO_2. As illustrated in Table 8, the highest cost rate considered by ENS is established by the 450ppm scenario, which is significantly lower than the main value reported by UBA. Carbon-dioxide is the main emission from natural gas combustion, as observed in Table 9, and so it composes the bulk of the external costs. Hence, the external cost parameter is highly sensitive to the CO_2 cost rate.

The values established by UBA (2014) are discussed in (UBA, 2012) and its Annex B. It is argued that the quantification of emissions considers both the direct and indirect emissions, and that the monetization of emissions uses the damage cost method. The standard discount rate adopted by the agency for cross-generational valuations is 1,5% per year in real terms, which reflects time preference of 0% (equal importance attributed for future and present generations), a elasticity of the marginal utility of consumption of 1, and an annual consumption growth rate of 1,5%. Hence, this is the rate used to discount future air pollution costs. For climate change in particular, the agency uses a different value for the discount rate due to a more conservative estimation of 1% per year for the economic growth rate of the next 100 years. So, using the same time preference of 0% and elasticity of 1, the real discount rate adopted for climate change costs is 1%[5] (Frey & Bünger, 2014). For comparison, the Stern Review uses a time preference of 0,1%, elasticity of 1, and growth rate of 1,3%, resulting a real discount rate of 1,4% per year (Stern, 2007).

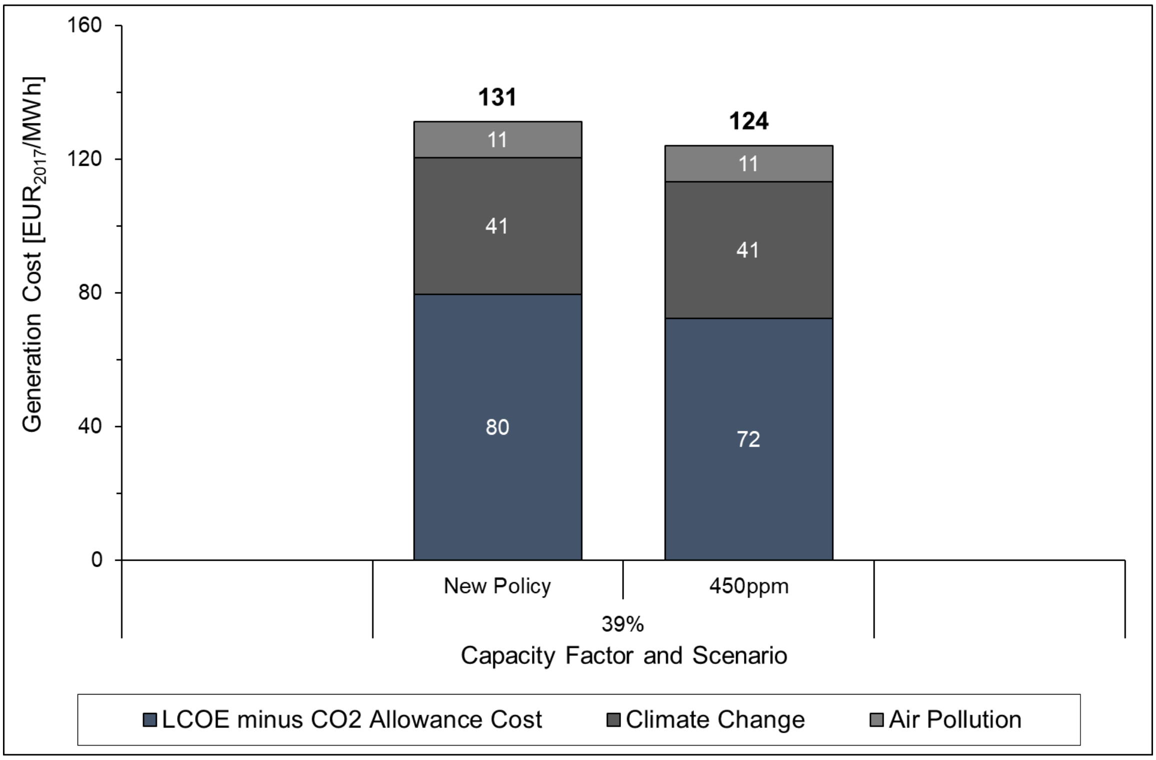
On the other hand, the scenarios by IEA do not present this discussion. It is not clear on whether indirect emissions are considered or not for quantification of emissions. Also, it is not clear if the institute adopts one of the monetization methods, as it calculates the CO_2 cost rate by region and according to the set of national policies in place. Nevertheless, it is possible to infer that it reflects the method of avoidance cost, since it uses a cost rate that promotes the necessary change to achieve a certain target.

Bringing the discussion to the objective of this section, the levelized costs of CCGT generation can now be compared to its external effects, which have been quantified and monetized. Both results are given in EUR/MWh and so they can be added to provide the total social cost per unit of generated energy. To account for the external costs, this research uses the values determined by UBA.

The analysis is made using the LCOE calculated in Sections 5.3 and 5.4. It is important to note that both the New Policy and the 450 ppm scenarios are used to account for different developments of market costs of natural gas and emission allowances, but not for the social cost of GHG. So, to avoid double counting of CO_2 costs, one prior adjustment necessary for this analysis is to subtract the emission right costs that composes the LCOE, the variable $Carbon_t$ in Equation (1).

The results of LCOE of CCGT generation at a capacity factor of 39% and the external costs determined by UBA are presented in Graph 9. For other values of capacity factor, the results are similar, as the externalities are variable costs.

[5] The discount rate is calculated as the social rate of time preference: $SRTP = \rho + (\varepsilon * c)$, where ρ is the pure rate of time preference, c is the growth rate of consumption, and ε is the elasticity of the marginal utility of consumption (Harris & Roach, 2013).



Graph 9. LCOE of CCGT generation and external costs according to (UBA, 2014), in EUR_{2017}/MWh.

As expected, the generation costs from a CCGT power-plant are higher when perceived by society. Some conclusions can be drawn from the results that help to answer sub-question III: *'Taking into account the external costs, is CCGT generation a low-cost source* of flexibility for the German power system*'*:

- The external costs of CCGT generation are significant when compared to its LCOE. While the LCOE vary between 79 and 117 EUR/MWh, for a new plant in 2020 and including the EU-ETS costs, the externalities amount to 52 EUR/MWh.
- When the externalities are added to the LCOE results, as shown in Graph 9, they represent 39% and 42% of the total costs in the New Policy and the 450ppm scenarios respectively (considering the reference case of a 39% capacity factor and excluding the EU-ETS costs to avoid double-counting).
- The effect of externalities on LCOE of CCGT is of an increase that ranges from 27% to 54% (considering all capacity factor values).
- It is possible to note that the stricter policies of the 450ppm scenario cause the societal perspective of LCOE to be lower, but only modestly. The valuation of CO_2 proposed by UBA presents a more robust discussion and uses a method that effectively reflects the costs imposed on society by climate change.
- From a societal perspective, CCGT`s externalities cause it to be even less attractive and oversupplied. The internalization of efficiently set external costs would lead to lower consumption of electricity from this source.

5.6.3. Societal Cost of Energy Storage

Energy storage system also have externalities and therefore should be considered in this research. The objective is to allow the policy analysis to examine the alternatives in a socially efficient manner. The addition of external costs to the LCOES results creates an appropriate base with which to compare the societal costs of CCGT generation calculated in Section 5.6.2.

Differently from CCGT generation, GHG emission of energy storage occurs mostly on the construction phase. Considering the fact that the three ES technologies considered in this research do not burn fossil fuel, this research assumes direct emissions to be null. Indirect emissions are mainly caused by the manufacturing process of the used equipment and material, such as turbines, concrete (Denholm & Kulcinski, 2004).

Indirect GHG emissions of ESS can be expressed in a rate of tonnes of CO_2 per MWh of installed capacity. CAES has the lowest rate among the options, estimated in 19 tonCO_2/MWh. The rates for PHS and VRFB are of 35,7 and 161 tonCO_2/MWh, respectively (Denholm & Kulcinski, 2004).

These rates are used here to calculate the external costs of the three technologies. The technical parameters defined by IRENA of installed power and storage capacity, and number of cycles per day, are considered. The calculation also uses the cost rate of CO_2 as defined by UBA, which is the same applied to calculate the social costs of CCGT generation. The results are presented in Table 16.

Table 16. External costs of ESS and impact of their LCOES, in EUR$_{2017}$/MWh

	CAES	PHS	VRFB
Levelized external cost	1,3	1,1	7,7
LCOES (new unit in 2020)	111,6	77,2	204,5
LCOES + External cost	112,9	78,2	212,1

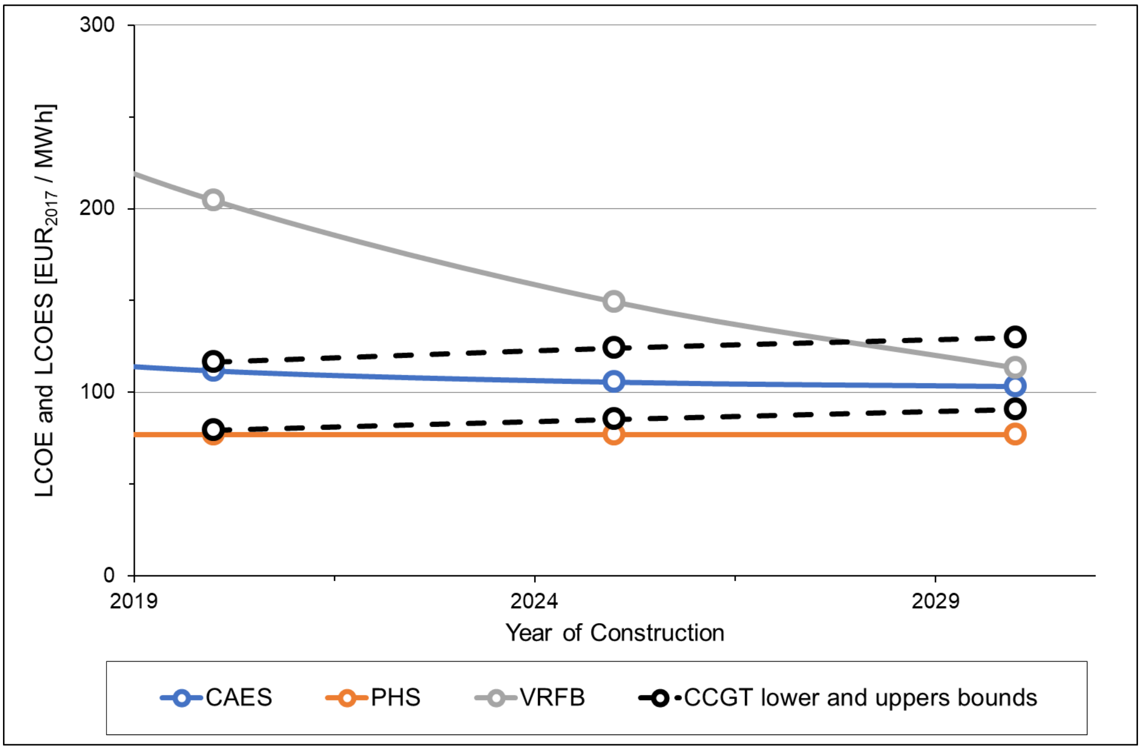
It is possible to observe that external costs of ESS are relatively low when compared to their LCOES. Externalities of CAES, PHS, and VRFB represent 1,2%, 1,4%, and 3,7% of their levelized cost of service. Moreover, ESS external costs are considerably lower than that of CCGT generation. The differences from the three considered technologies to CCGT generation are of -97%, -98%, and -85%, respectively.

5.7. Discussion on CCGT and ESS Costs and Electricity Prices

In the previous sections, CCGT generation competitiveness was examined regarding its evolution over time and how it is impacted by the expected capacity factor. This section compares the LCOE results with the three ESS selected technologies and with electricity wholesale market prices in order to obtain further insights over its competitiveness. On one hand, the comparison of results on LCOE and LCOES helps understanding how energy generation firms will perceive gas-fired generation as an attractive investment option. On the other hand, the comparison involving their external costs indicates the societal perspective on their attractiveness as policy options.

5.7.1. LCOE and LCOES Comparison without External Costs

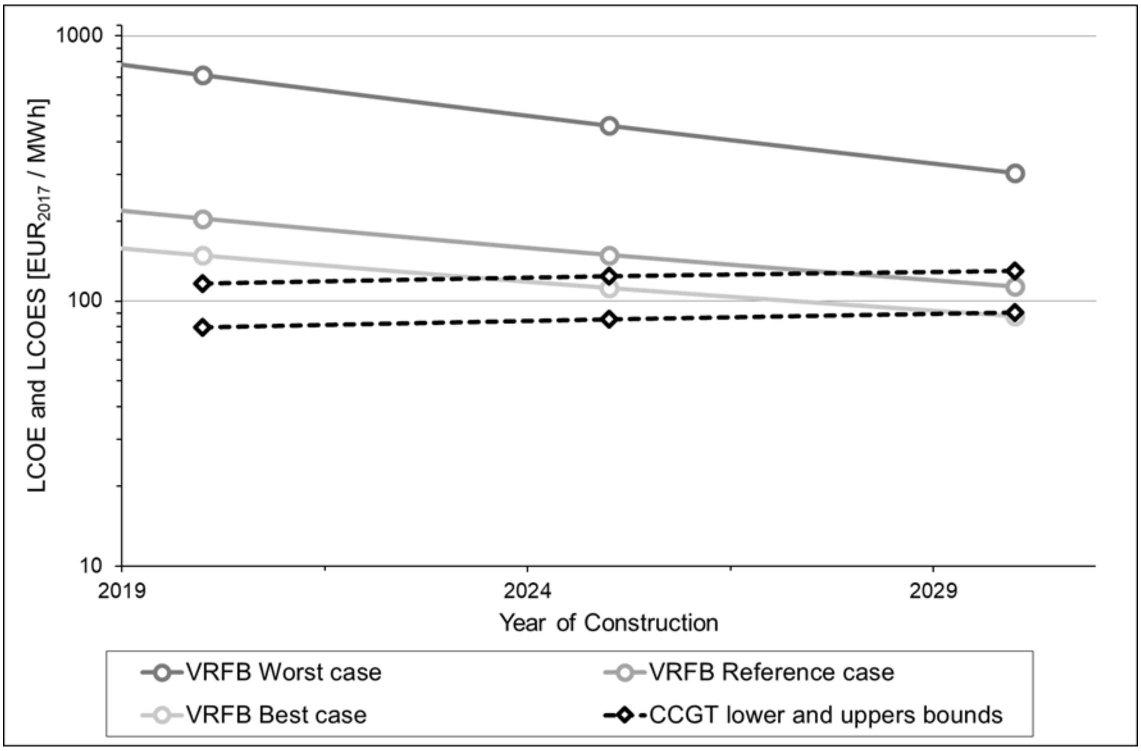
The comparison of the results for LCOE of CCGT generation and for LCOES of CAES, PHS, and VRFB is presented in Graph 10. The levelized costs are for new units entering operation in 2020, 2025 and 2030. The cost for CCGT are given as a range delimited by two curves, comprehending the lowest and highest values of each year, i.e. the highest and lowest capacity factors. For the ES technologies, the reference cases are presented.



Graph 10. LCOE and LCOES results comparison, in EUR2017/MWh.

CCGT generation have costs similar to the two ES mature technologies (CAES and PHS) for new units in 2020. For the next years, the storage costs are expected to change modestly, while CCGT costs are likely to increase, due to natural gas and emission costs. So, gas-fired generation will gradually become less competitive than CAES and PHS.

Regarding VRFB, CCGT currently has significantly lower costs. The first has a LCOE from 79 to 117 EUR/MWh, while the second has a LCOES reference case of 204 EUR/MWh. This difference is expected to decrease until 2030, as vanadium batteries technology improves. For new units to be built in 2030, the battery`s LCOES reference case falls within the LCOE range. However, it is important to note that VRFB is in an evolutionary state and, so, that its cost evolution is uncertain. The comparison is then expanded to incorporate this cost range, illustrated in Graph 11 (in log scale to facilitate the visualization).

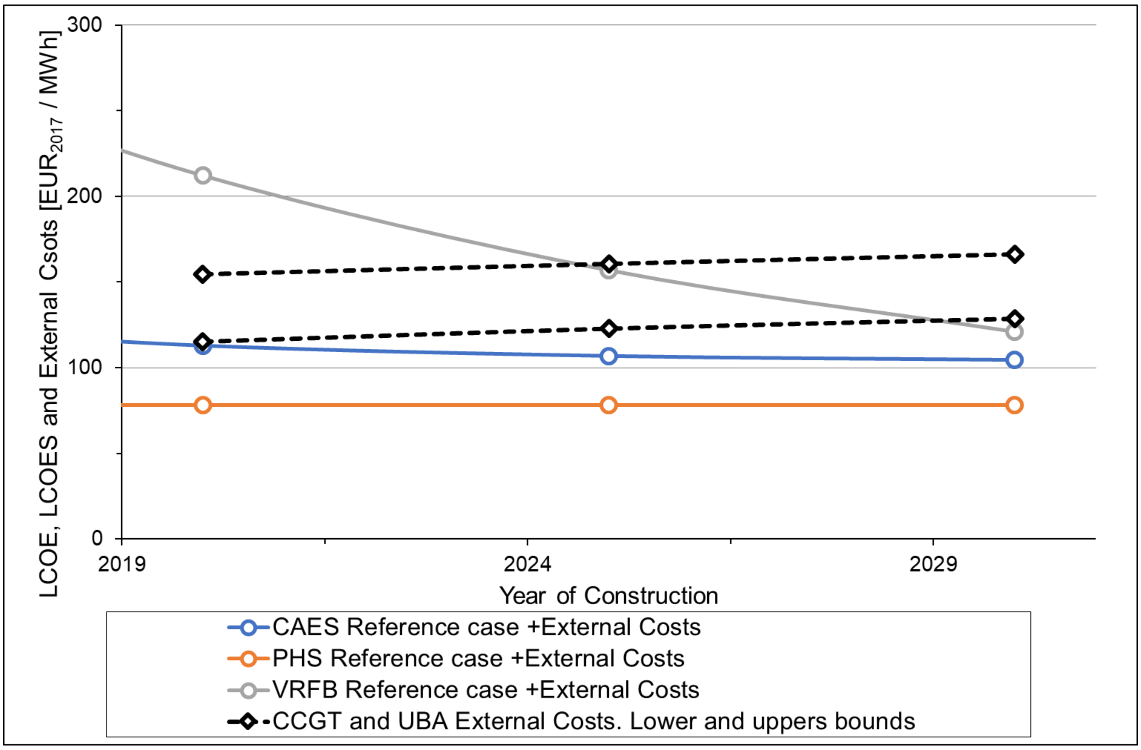


Graph 11. CCGT and VRFB cost ranges comparison, log scale in EUR2017/MWh.

The worst case proposed by IRENA for the LCOES of VRFB in 2030 is 304 EUR/MWh, 134% higher than the upper bound for CCGT LCOE. Conversely, the best-case value of 88 EUR/MWh is 4% lower than the lower bound for a gas-fired plant. So, the competitiveness evolution of CCGT against VRFB is unclear: while the reference case for the battery option is of significant potential for cost reduction and to become competitive with CCGT generation in the perception of energy generation actors, it is also possible that it remains less competitive.

5.7.2. LCOE and LCOES Comparison with External Costs

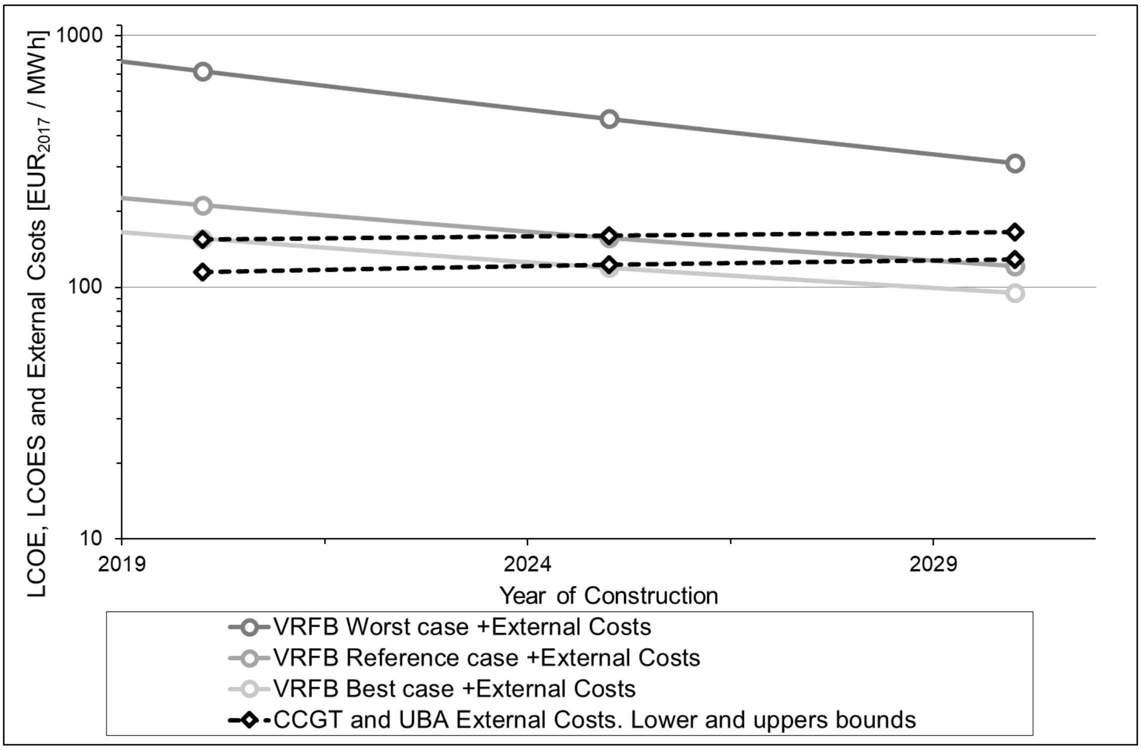
Graph 12 presents the cost-comparison of CCGT, CAES, PHS, and VRFB, including their external costs. Similar to the previous section, the levelized costs are for new units entering operation in 2020, 2025 and 2030. The cost for CCGT are given as a range and for the ES technologies, the reference cases are presented.



Graph 12. LCOE, LCOES, and external costs results comparison, in EUR2017/MWh.

The inclusion of externalities to the LCOE and LCOES results provide the perspective of society on the attractiveness of these flexibility options. Gas-fired generation has larger external costs, as it burns a fossil-fuel, and so its competitiveness is further compromised. For a new unit in 2020, CAES and PHS levelized costs are both lower than the lower bound for CCGT: 78, 112, and 115 EUR/MWh, respectively. The difference increases until 2030, when, for instance, the lower bound for CCGT is 24% higher than CAES.

The comparison of CCGT with VRFB provides results more favourable for the latter, as its external costs are also lower. For a new unit in 2020, a gas-fired plant has lower costs than the battery option, but the difference is lower than when externalities are not considered. Additionally, in 2030 the VRFB reference case becomes more competitive than the lower bound of CCGT costs, differently from the previous section. This examination is expanded by including the best and worst cases for VRFB cost, as presented in Graph 13.



Graph 13. CCGT and VRFB ranges of generation and external costs, log scale in EUR$_{2017}$/MWh.

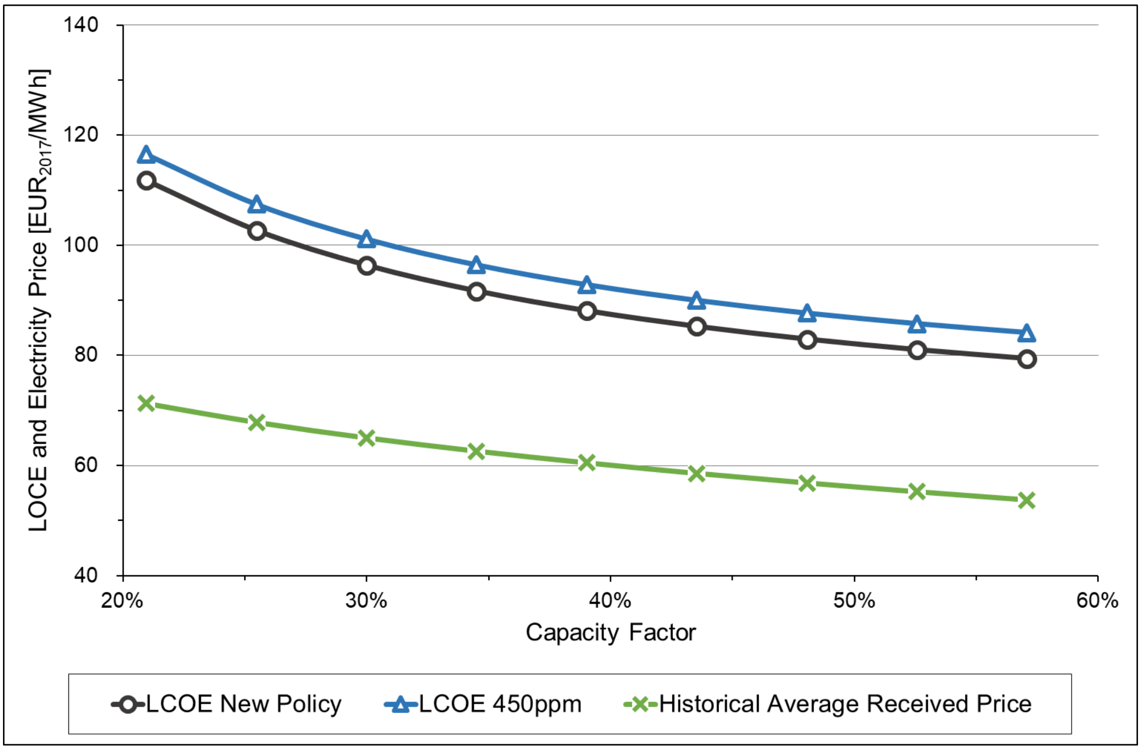
Despite the fact that higher external costs of CCGT generation changes the competitiveness perception in favour of the ESS for all scenarios, the uncertain cost development of the battery option again poses important in the comparison. The worst cost-case for VRFB for a new plant in 2030 is set as 312 EUR/MWh, 88% higher than the upper bound for a new gas-fired plant. Hence, societal perspective on the competitiveness of CCGT plants against VRFB is also unclear.

5.7.3. LCOE Comparison with Electricity Prices

The comparison of the obtained LCOE results with Germany`s wholesale electricity price on the day-ahead market provides supplementary insights on CCGT generation competitiveness. According to Borenstein (2012), the LCOE indicates the constant price of power in real terms that would equate the net present value of revenues and costs.

To perform this comparison, this research uses the LCOE of a CCGT power-plant to start operation in 2020, considering both the New Policy and the 450ppm scenarios. As in Graph 2, the levelized cost is presented for several levels of capacity factor. The electricity prices represent the average price the plant operator would obtain if it was dispatched under a certain capacity factor. It is assumed that the CCGT plant is dispatched in the moments of highest prices - as a flexibility source, it runs in moments of low supply availability, i.e. low wind and solar output. The data refers to historical prices observed in the German electricity market between January 2006 and July 2018.

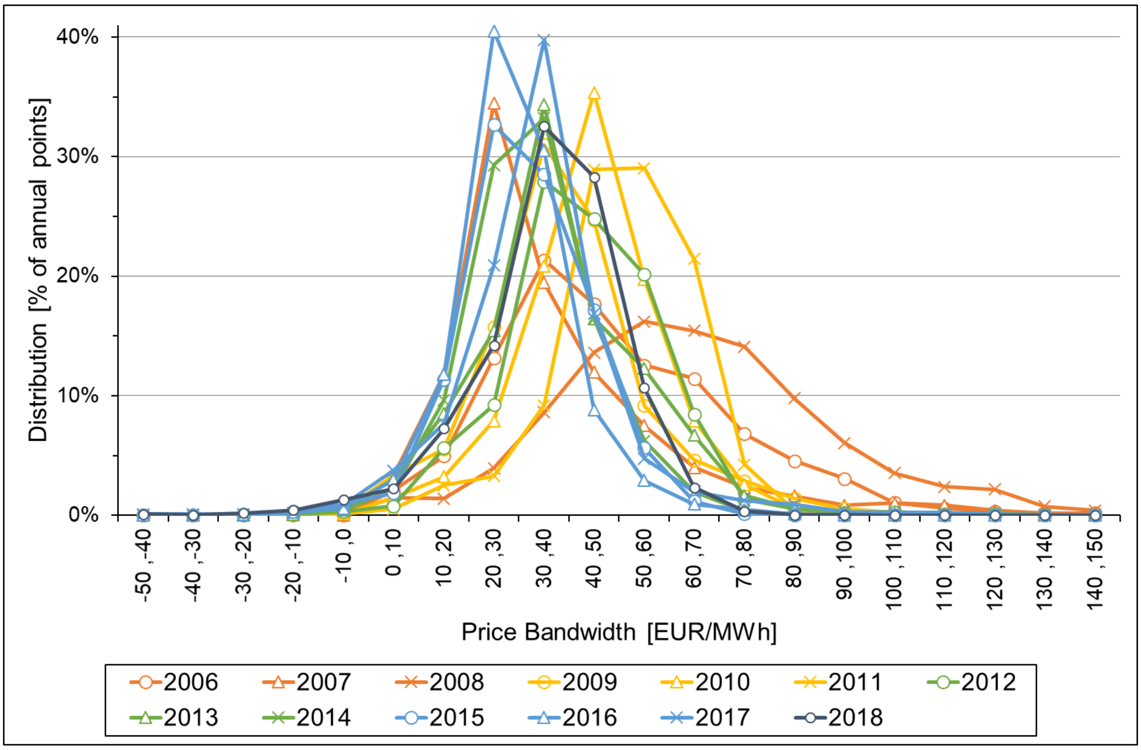
The comparison is illustrated in Graph 14. The results show that spot-prices are lower than the LCOE calculated in this research throughout the entire range of capacity factor uncertainty. The difference varies from -26 to -45 EUR/MWh, or -32% to -39%. The difference is higher for lower capacity factors and under the 450ppm scenario. The results reinforce the idea that the CCGT option is not likely to be appealing to the generation actors in Germany. If this condition is to be changed, market prices would have to increase by these differences – however, the actual cost incurred to society can only be measured together with CCGT`s external costs.



Graph 14. LCOE of CCGT generation and wholesale electricity prices, in EUR/MWh.

A closer look into the price dataset reveals interesting insights. Graph 15 presents the distribution curves of each year (the series is limited at the price range from -50 to 150 EUR/MWh, which contains at least 99% of the points of each year). The market prices present a distribution highly concentrated within the range of 20 and 50 EUR/MWh, which contains 64% of the 109.704 data points. This helps to explain the relatively small slope of the price curve in Graph 14.

When the evolution over time of the concentration patterns is analysed, it is possible to observe that prices are clustering more on the bandwidths of 20 to 40 EUR/MWh in recent years, with a more modest tail over higher prices. This indicates an overall wholesale electricity value decrease – the literature proposes that higher shares of RES cause price reduction. Hence, the price curve in Graph 14, that considers all data points between 2006 and 2018, is possible to reduce following this tendency. In this case, CCGT generation competitiveness can be further damaged.



Graph 15. Annual distribution of electricity prices.

5.8. Discussion on the System Actors` Perspective about Generation Costs

This research focuses on the implications of a large share of RES on the incentive that CCGT generation actors have to invest in new power-plants. This research also focuses on the policy challenge to the energy transition in Germany brought by the increasing requirement of flexible sources and whether the new policy framework is adequate to attract CCGT investment. Therefore, a discussion is necessary on the perception that CCGT generation firms and the Ministry of Economic Affairs and Energy have on the results obtained in this research.

For this end, the results of cost-competitiveness are put into perspective using the multi-actor analysis performed in Section 2.2. The identified interests, goals, means, and perceptions that the most relevant actors have towards the broad transformation process of the German power system, i.e. the Energiewende, are used to infer their perception on the specific case of CCGT generation as a source of flexibility. The inferred perceptions are presented in Table 17 and then discussed.

Table 17. Results perception from CCGT generation firms and the Ministry of Economic Affairs and Energy

<table>
<tr><th>Results</th><th>Perceptions from CCGT Generation Firms</th><th>Perceptions from the Ministry of Economic Affairs and Energy</th></tr>
<tr><td>The capacity factor of CCGT generation for the next decades is uncertain, and observed in this research to be between 21% and 57%. This uncertainty is passed on to its LCOE, which has a significant range: 79 to 117 EUR/MWh for a new plant entering operation in 2020.

Additionally, this entire range of LCOE is higher than electricity prices of the wholesale market.</td><td>Given the results of this research, this actor niche has a negative perception on the future market conditions. They will be less prone to invest in new plants between 2020 and 2030.</td><td rowspan="2">The results are in line with the Ministry`s intention for market forces to select the most cost-efficient flexible sources.

The tendering process for new RES plants can help the Ministry to keep the intermittency level in accordance with market developments of flexible sources.</td></tr>
<tr><td>CCGT generation is not cost-competitive against CAES and PHS. These two ESS are mature technologies and can provide flexibility similarly to CCGT plants. However, they are site-dependent and, hence, have limited potential for expand.</td><td>CCGT generation firms perceive their market share is threatened due to competition against these storage technologies, which worsens their incentive to invest. The extent of this effect depends on the expansion potential of CAES and PHS.</td></tr>
<tr><td>CCGT generation has considerable chances of becoming less cost-competitive than VRFB. Vanadium battery technology has two important characteristics: it is not site-dependent, so it can be scaled up to provide system flexibility without limitation of favourable locations; it is an evolutionary technology, so cost development is uncertain and it is possible for it not to evolve as expected until 2030.</td><td>There is a risk that CCGT generation will become less competitive than new VRFB units in 2030. Given the long-term nature of investments in the power sector, this future cost-disadvantage reduces the chances of new investments in gas-fired plants even now.</td><td>The Ministry sees in a positive way the development of new technologies to provide flexibility. It contributes with goals from the Energiewende and from the desire to be in the technology run frontier.

An early, market-driven phase-out of CCGT generation creates a situation of attention between 2020 and 2030.</td></tr>
</table>

External costs from CCGT are 52 EUR/MWh. The societal perception on CCGT generation costs is between 115 and 155 EUR/MWh, which is 27% to 54% higher than the market perception for a new power-plant in 2020. So, CCGT`s externalities cause it to be even less attractive from the social perspective. External costs of storage are considerably lower. Analysing the levelized costs from the societal perspective, i.e. including externalities, CAES and PHS are more competitive than CCGT for new units in 2020, 2025 and 2030. VRFB reference case becomes more competitive than CCGT in 2030.	Costs with CO_2 allowances will have limited impact on gas-fired generation costs and electricity price formation. Future emission prices are not forecasted to reach the level proposed by UBA, for instance.	CCGT externalities cause it to be even less attractive from the perception of the Ministry in terms of generation costs. So, it is actually oversupplied by the market. Policies to incentivize CCGT generation are economic inefficient.

The first point of discussion about the actors inferred perception on the results of this research is the uncertainty level of the capacity factor and LCOE of CCGT generation, and the comparison against electricity prices and compressed air and pumped hydro energy storage costs (lines 1 and 2 from Table 17).

According to Debor (2018); Fischer et al. (2016), CCGT generation firms acted in order for the Electricity Market 2.0 to implement a capacity mechanism. This would improve their competitive conditions, as new revenue stream would remunerate the available installed capacity and its contribution to system reliability. According to Strunz et al. (2016); Sühlsen and Hisschemöller (2014), the means to do so were lobbying, maintaining direct contact with policy-makers, and seeking to influence the public opinion, which is currently favourable to the Energiewende. Considering that the federal government opted to not implement a capacity mechanism, CCGT firms did not obtain success in their attempt and their revenue remains based on electricity sales on the wholesale market. Hence, cost-competitiveness in the energy-only market is an important investment decision criterion for their interest in maximizing profits. In light of the results of this research, CCGT generation firms will be less prone to invest in new plants between 2020 and 2030 due to uncertain LCOE and diminishing wholesale market prices.

Competition against CAES and PHS causes CCGT generation firms to perceive the current market situation to be further unfavourable. They perceive their market share is threatened due to disadvantage of cost-competition. This effect is limited to the extent that compressed air and pumped hydro can be expanded in Germany. Therefore, CCGT generation firms` goal to protect their market share from RES, as suggested by Strunz et al. (2016), can be extended to protect their share against current competitive ESS.

Conversely, the of Economic Affairs and Energy does not observe the outcomes for gas-fired plants in an isolated manner. Rather, the results are in line with the idea that market forces will select the most cost efficient flexible sources (Amelang & Appunn, 2016; BMWi, 2015). From a cost perception, generation actors will favour investment in CAES and PHS over CCGT from 2018 until 2030, at least until the exhaustion of the appropriate sites for the two sources. In the sense the federal government manages welfare among stakeholders (Strunz et al., 2016), the Energy Market 2.0 does not allocate welfare for CCGT generation actors – it favours RES generation companies by continuing the FIT programmes and reinforcing the energy transition goals. The new tendering process benefits households for limiting the EEG surcharges.

It is also interesting to note that the federal government is prudent with the short-term targets for RES share in Germany and sets the more ambitious goals for 2050 (Fischer et al., 2016). The decision for a more progressive transition alleviates the burdens of operation challenges that may arise from the insertion of energy storage sources with which the market has little experience with. Additionally, one new instrument the Ministry has to deal with eventual difficulties is the tendering process for new RES plants, which enables control over the expansion of wind and solar plants (Debor, 2018). This can help the Ministry to keep the intermittency level in accordance with market developments of flexible sources.

Another set of results from this research that requires a discussion on actors' perception is the cost-competitiveness of gas-fired generation against VRFB energy storage (line 3 from

Table 17). Vanadium battery is an evolutionary technology whose costs can drop significantly in the near future. Hence, CCGT generation firms making an investment decision in 2018 for a new power-plant to enter operation in 2020 perceive the risk that, within 10 years of operation, the plant will become less competitive than a new VRFB unit. Considering that the lifetime of gas-fired unit is of 30 years, this plant would be dispatched for fewer hours during two-thirds of its lifetime due cost-disadvantage against a ESS that can be scaled-up without the restrain of favourable sites. As a consequence, the ability of the gas-fired plant operator to recover the investment is further compromised. Considering the cost side of investment assessment, and if the CCGT generation firm is capable of foreseeing this scenario, the chances of one effectively investing in a new plant for 2020 is reduced.

For the Ministry, the result addresses two goals from the Ministry. First, VRFB contributes with the increasing flexibility requirement that enables the ambitious goal of RES generation for 2050, as suggested by Debor (2018). VRFB development also relates to the goal of technological leadership related to energy transition (Joas et al., 2016). One point of attention is that, from 2020 until 2030, both CCGT and VRFB do not seem attractive for new investments. Given the site-limitation nature of CAES and PHS, this situation might have implications for the Energiewende during this period of time.

The last point of discussion about the actors inferred perception is around the obtained results on external costs (line 4 from Table 17). For CCGT generation firms, the costs of GHG and air pollutants emission their activity causes are presently not fully imposed on them and, therefore, they impact the electricity price formation in a limited manner. Moreover, the scenarios of future fuel and emission prices do not envision CO_2 emission allowances reaching a price that effectively reflects the cost imposed on society by climate change. This CO_2 price formation through market mechanisms is in line with their neoclassical view for emissions valuation (Strunz et al., 2016). If CO_2 cost is not efficiently set, the impact of emissions on cost-competitiveness of CCGT generation is limited, as natural gas is the fossil-fuel with the lowest emission levels.

On the other hand, external costs are of great importance for the Ministry, as they are essential to promote social efficient energy policies (Goulder & Parry, 2008). Hence, the Ministry perception of CCGT generation as an instrument for system flexibility is impacted by the climate change and air pollution costs, which are not fully considered by market actors when they decide on their output level. From a societal perspective and the government's ideological interest to combat climate change (Joas et al., 2016), CCGT externalities cause it to be even less attractive in terms of generation costs and oversupplied by the market. Therefore, policies to incentivize CCGT generation will be perceived as economic inefficient by the Ministry, especially considering that eventual new CCGT plants on the next 10 years would create long-term lock-ins and that VRFB might become competitive in 2030. This would be in conflict with the government`s interest of low electricity costs for society (Joas et al., 2016).

6. Conclusions

This research examined the impacts from high shares of RES the investment incentive for CCGT power-plants in Germany using generation costs as criterion. The motivation is that the success of the energy transition depends on adequate provision of system flexibility to compensate for the intermittent nature of wind and solar units. Gas-fired plants are a well-known option, but there is a concern over its profitability due to reduced number of running hours.

The German federal government recently made the policy option to continue as an energy-only market, under the belief that market forces are capable of selecting the most economic efficient sources to provide the necessary flexibility. So, this research used the LCOE method to investigate the perception of generation firms on CCGT competitiveness and its attractiveness as an investment option. There is no prior research that applies this method to investigate generation costs of gas-fired plants in a scenario of growing shares of RES. Therefore, cost variables were scrutinized in order to compose a scenario compatible with the future of the German power market. Complementary, three energy storage technologies that can provide flexibility in the same basis as CCGT were assessed for comparison purposes, and externalities were considered to assess flexibility options from a societal perspective.

This section uses the obtained results from Sections 5.1 through 5.6 to answer the three research sub-questions. The discussion presented in Sections 5.7 and 5.8 are used to provide an answer for the main research question. The section is completed with reflections on the methods, results and future research.

6.1. Answers for the Research Sub-Questions

Sub-Question I: What is the expected capacity factor for CCGT generation in Germany during the energy transition?

The examined literature indicates that high shares of RES in power systems reduce the capacity factor of CCGT generation. The importance of the capacity factor is manifested mainly on the investor's capacity to recover fixed costs. During the initial literature review, it was found that specialists' forecasts for CCGT capacity factor are divergent, although the levelized cost of this type of plant is heavily dependent on the utilization rate. Hence, the first part of this research investigates this uncertainty and delineates the range.

The results and discussion presented in Section 5.2 confirm the initial indication that the future capacity factor for CCGT generation is uncertain. The research found that there is no consensus on the forecast of this variable for the next decades, i.e. or for the lifetime of new power-plants to be built in 2020, 2025 and 2030. Similarly, it was not found any debate about the probability distribution for the variable, the feasibility of scenarios or ranking of likelihood. This research found that the capacity factor for CCGT generation is uncertain and it then investigated the implications of an uncertainty range between 21% to 57%.

Sub-Question II: From the perspective of a single firm, how does the reduced capacity factor for CCGT generation in Germany affect its competitiveness in terms of generation costs?

The initial literature review also presented concern over the economic profitability of CCGT power-plants. Cost comparison of power generation and clear understanding of its uncertainties are key inputs for the discussion of energy policies. At the firm's level, the LCOE method expresses the investment cost-side, which allows for an investigation of the influence of the capacity factor. In other words, the LCOE indicates the constant price of power in real terms that would equate the net present value of revenues and costs.

The results and discussion presented in sections 5.3 and 5.4 confirm the concern over the economic viability of CCGT power-plants, using generation costs as a criterion. The LCOE result for a new CCGT plant to enter operation in 2020 is between 88 and 93 EUR/MWh, in the New Policy and the 450ppm scenarios respectively. The levelized cost is higher for new units in 2025 and 2030, reflecting natural gas prices and emission cost. Moreover, it was found that the uncertainty of the capacity factor variable is propagated to the LCOE – for instance, the levelized cost ranges from 79 to 117 EUR/MWh for a new plant entering operation in 2020, i.e. a difference of -10% and +27% relative to the reference case.

LCOE results are larger than wholesale market prices. The difference varies from 26 to 45 EUR/MWh for a new power-plant in 2020, which reinforces the idea that CCGT is not an attractive investment option regarding costs.

Concerning energy storage, compressed-air and pumped-hydro storage have LCOES of 112 and 77 EUR/MWh for new units in 2020, respectively. These results are similar to the CCGT generation costs. One important limitation is that these two options are site dependent and might have restricted expansion capacity. Conversely, vanadium batteries are not site-dependent but have a current levelized cost of 206 EUR/MWh. Although not competitive against gas-fired plants in 2020, technological development can reduce its costs to 113 EUR/MWh by 2030, making it a more attractive investment option.

Sub-Question III: Taking into account the external costs, is CCGT generation a low-cost source of flexibility for the German power system?

Climate change and air pollution are the main externalities from the power sector and, so, they cause the total output of fossil-based activity to be inefficient. Hence, energy policy must consider the external costs of CCGT generation to ensure social efficiency. In this manner, it is possible to obtain the perception of the federal government on whether CCGT is an attractive technology to deal with increased intermittency in terms of costs.

Among the externalities, CO_2 emission cause the most relevant cost. Current CO_2 valuation observed in the EU-ETS and future scenarios proposed by IEA reflect market conditions, but not the actual costs imposed on society due to climate change. The valuation proposed by UBA (2014) is used to fully account for this cost.

The results and discussion presented in Section 5.6 show that, from a societal perspective, externalities from CCGT generation are relevant when compared to its market value. CCGT external costs are 52 EUR/MWh, causing generation costs to increase to the range of 115 and 155 EUR/MWh (new unit in 2020). This represents a rise of 27% to 54% relative to LCOE perceived by market actors.

External costs of storage are considerably lower. For a new unit in 2020, CAES and PHS LCOES are 2% and 32% lower than the lower bound for CCGT respectively. The difference increases until 2030, reaching 19% and 39% in the same comparison. The comparison with VRFB shows that a gas-fired plant has lower costs than the battery option for a new unit in 2020, but the difference is lower than when externalities are not considered. The outcome changes for new units in 2030, when VRFB has costs 6% lower than the lower bound of CCGT. Although vanadium batteries become more competitive using its reference case, it is unclear whether it will achieve such cost development.

From a societal perspective, CCGT`s externalities cause it to be even less attractive and oversupplied. The internalization of efficiently set external costs would lead to lower consumption of electricity from this source.

6.2. Answer for the Main Research Question

The answer for the main research question is obtained analysing the obtained results against the backdrop of Germany`s energy policy framework and the multi-actor system analysis. The research question was formulated as follows:

Is CCGT generation a good alternative in terms of costs for the need of flexibility of the German power system during the energy transition, given increasing intermittency and risk to the security of supply?

In light of the results and the multi-actor analysis presented in Table 17, CCGT generation companies in Germany will not have sufficient incentive, in terms of generation costs, to invest in new power-plants between 2020 and 2030. The capacity factor for this power source is under uncertainty, which is passed on to its LCOE. CCGT generation costs are higher than electricity wholesale prices and higher than the costs from compressed-air and pumped-hydro storage. CCGT is likely to be not cost-competitive against vanadium batteries in 2030 either. Given that the new policy framework did not create a capacity mechanism, as pleaded by conventional generators, they remain dependent on energy sales alone. This future scenario of the Energiewende makes investment in CCGT plants not economically viable in term of costs.

CCGT generation is not a cost-effective option for flexibility from a societal perspective either. Its external costs are large relative to its own levelized costs and also when compared to energy storage options. So, under the societal perspective, its competitiveness is further diminished. For the Ministry of Economic Affairs and Energy, energy storage is more advantageous than CCGT between 2020 and 2030.

There are two points of attention regarding energy storage. The first is that the current competitive options, CAES and PHS, are restricted to locations that allow their construction, which can limit their expansion. The PHS potential is estimated in 45 GWh (eStorage, 2015), and CAES potential is suggested as 370 GWh[6] (Klumpp, 2015). In order to put this value into perspective, the total estimated storage requirement in Germany in 2050 is taken from Sinn (2017) and Zerrahn, Schill, and Kemfert (2018). The former argues that 2.114 GWh of storage will be needed. The latter authors argue that Sinn`s research does not consider an economic efficiency perspective, making use of only extreme cases to either store all or none of the RES surplus (corner-solutions). Therefore, they find a lower storage requirement for Germany in 2050: 462 GWh, allowing a RES curtailment of 16%. Despite the fact that both studies have considerably different results, both estimates are higher than, for instance, the PHS potential of 45 GWh.

The second point of attention regarding storage is that the VRFB technology is undergoing a learning curve, configuring a capital-intensive and high-risk investment (World Energy Council, 2016). Hence, it depends on R&D investment to effectively become cost-competitive by 2030 as projected. Mazzucato and Perez (2014) argue that the private sector might be too risk-averse for such, and that investment in innovation is often triggered by direct public investment “along the entire chain, from basic research, applied research and early-stage financing of companies”. Hence, the risk is that, if left for market forces alone, the technological progress will not be observed.

The results suggest that Germany will likely see reduced investment in CCGT, and that the national power system will have to rely on other sources of flexibility for the future. Reduced cost-competitiveness could even cause the closure of existing natural gas plants. This is in line with the principle of a competitive market and the selection of the most cost-efficient sources. Moreover, eventual policies to incentivize gas-fired generation would create long-term lock-ins that would be economic inefficient, since energy storage are steadily becoming more cost-competitive. The government`s policy decision to not implement a capacity mechanism is consistent with this thought.

Thus, the national energy security and the Energiewende depend on the materialization of other flexible electricity sources. Before 2030, vanadium batteries are unlikely to expand in significant levels, and compressed-air and pumped-hydro storage are limited to suitable locations. This creates a situation of attention for Germany. The federal government was prudent in choosing modest short-term targets for RES and more ambitious goals for 2050. However, if the market forces are not able to promote adequate investment, the government will have to use the tendering process to decelerate wind and solar expansion.

Considering that energy storage is an important drive for the energy transition (IRENA, 2017) and that vanadium batteries are not constrained by geological conditions, the German Ministry of Economics Affair and Energy can aid with this learning curve. If it comes to perceive VRFB as an opportunity to provide system flexibility, it can play the role of entrepreneur and invest in R&D in order to reduce the risk of its cost development. Alternatively, the government has the instruments of feed-in tariffs (Strunz et al., 2016), and can direct resources from this support scheme to ES firms in a similar fashion as it does for RES generation firms.

[6] There is little existing research to estimate the storage potential with CAES in Germany. The cited study presents only a brief discussion on the likelihood of his results.

7. Reflections and Future Research

This research succeeded in the investigation of the investment attractiveness on CCGT power-plants in the presence of a large share of RES using generation costs as a criterion. The perspective of both generation firms and the government were evaluated, producing insights for the German energy policy framework. The results for this country, which is a front-runner in renewable energy expansion, collaborate with the challenge that policy-makers face in promoting flexible sources in a scenario of less favourable investment conditions for conventional technologies. The conclusions can help to orient future research for Germany and other countries seeking to transition their energy matrix.

Although the research succeeds in assessing how attractive CCGT generation is for investment actors and for society, it has some limitations, which are presented in this section. Additionally, other policy alternatives that can be used to tackle the problem in hand are discussed, as well as other metrics that can complement the obtained results.

7.1. Research Limitations

One of the limitations of this research refers to the criticism on the LCOE method for not considering the value energy has in time and location, as argued by Joskow (2011). Moreover, the method is not appropriate for the complete viability assessment of a single project, what would require the consideration of all revenues as well, besides its technological and regional characteristics (EIA, 2017; Kost & Schlegl, 2018). Since the method considers only the cost-side of the investment appraisal, it cannot evaluate the value one dispatchable power-plant has for the system in moments of scarcity. To mitigate this point, LCOE results were compared to electricity peak-prices, i.e., it is assumed that CCGT generation has a greater market value and that it is dispatched in the moments of greatest scarcity.

Another limitation is the dataset of electricity prices. In face of the difficulty to collect data on price forecasts that assume a scenario similar to the one proposed in this research and are publicly available, this research opted to use historical data. Twelve years of wholesale prices from the day-ahead market were considered. Also, the evolution of the prices over each year was considered in the discussion, to account for the reduction of prices caused by a high share of RES. Nonetheless, it is not clear how future prices will relate to past prices.

The third point to be discussed is the consideration of energy storage for comparison purposes against CCGT. Gas-fired plants are largely used in Germany and several other countries for a long time. So, apart from being a mature technology, generation actors have considerable knowledge of its operation and adjacent sectors (e.g. natural gas and emission markets). The same is not true for ESS, even for CAES and PHS, which are also considered mature technologies. The fact that there is less practical experience with these technologies can hinder the scaling up of their capacity to effectively characterize it as a perfect replacement for CCGT plants.

7.2. Other Uncertainty Factors

The assessment of CCGT generation attractiveness as an investment option can be expanded by scrutinizing the implications of the uncertainty of other variables, e.g. the discount rate and emission costs. The uncertain nature of investment in power generation is considered in this research through the capacity factor variable, which reflects the consequences of RES integration. Sensitivity analysis is performed with other variables for comparison purposes, however, the scenarios they imply are not debated.

For the discount rate, the range from 4,9% to 9,1% in real terms, i.e. -30% and +30% relative from the reference value of 7%, is considered in the sensitivity analysis. The choice for the central value is based on the examined literature, in special on IEA and NEA (2015), which adopts one single value for the interest rate in order to compare several different technologies on the same basis. The report argues that the cost of capital in the power sector reflects the uncertainty of future electricity market prices, capacity factor, input costs, among others. Hence, investors demand a premium in return for the market and regulatory risks. The report presents an example to estimate the cost of capital for an electric utility using the WACC and CAPM methods. In a regulated environment, the expected WACC is 3% in real terms[7], but the agency argues that “matters change radically” in a competitive environment. However, the discussion that leads to the conclusion that a 7% interest rate is more appropriate to account for the investment risks is brief. The arguments presented are qualitative and state that “risk-averse investors demand average returns higher than the risk-free rate” and that in a competitive market “investors seek to compensate themselves for the riskiness of their investments”. The report does not detail quantitatively the adopted rate. It also suggests a rate of 10% for riskier markets (IEA, 2015, p. 141).

The discount rate is also discussed by Borenstein (2012). The author calculates the LCOE for residential solar panels with a range of discount rates: 1%, 3%, 5%, 7%, and 9%, in real terms. He argues that the first two values are more appropriate for social discount rates, while the others reflect “those interest rates that most actual buyers would face”. The range of 5% to 9% that the author suggests for the analysis from a market actor perspective is similar to the range used in this research for the sensitivity analysis.

Conversely, Kost and Schlegl (2018) proposes a level of interest rate lower than the previous authors. They calculate the WACC for RES under support schemes, i.e. under more certain revenue flows, and for CCGT. The report suggests WACC between 1,8% and 2,7% for RES (with the exception of offshore wind with a rate of 4,8%). For CCGT, the WACC is calculated at 5,2%, all in real terms. The latter value is higher due to a higher perceived risk, which in turn leads to a lower level of debt and a higher required return on

[7] The agency uses a nominal risk-free rate of 3% on a 30-year bond, a beta of 0,4, a nominal market rate of return of 8%, and equal composition of debt and equity.

equity. For RES the return on equity is proposed between 5% and 8%, for CCGT it is 10% (in nominal terms).

It is clearly not straightforward to set a discount rate for the investment assessment. IEA`s proposition is closer to the upper-bound of the range used by Borenstein and the range adopted for the sensitivity analysis in this research, while Fraunhofer ISE`s WACC calculation is at the lower-bound. Market actors adopting the highest end of the interest rate range would either be observing very risky market conditions or advocating for higher electricity prices and revenues. In turn, if investment assessment is carried out with the lower values of interest rate, it could lead to more additions to the system installed capacity, higher supply reliability and cost-efficiency for the consumers.

A similar reflection can be made for the scenarios of fuel and emission costs. The New Policy and the 450ppm scenarios from IEA consider a trade-off between the two variables: climate change policies change the emission allowance prices, which in turn cause an opposite effect to the natural gas demand and prices. However, it is relevant to consider different outcomes, in particular the scenario where both variables remain at low levels simultaneously. In this case, the LCOE could be 25% inferior[8], causing gas-fired generation to be cost-competitive with energy storage and close to the wholesale market prices.

The fact that CCGT generation would remain a viable investment option in Germany, in the perspective of generation firms, has consequences for the power sector and for society. On one hand, the integration of higher shares of RES is facilitated, as gas-fired generation is the option for flexibility that is well-known for operators and investors. Acceleration of the Energiewende is desired by the German federal government and by households. On the other hand, innovation in new, cleaner sources of flexibility is set back due to the path-dependency characteristic of power systems. This is in contradiction with society’s goal to maintain Germany as technological frontrunner and a nation of engineers. This scenario can be seen as a trade-off between short and long-term goals, for which policy-makers need to be prepared for. One option is to take advantage of a cost-competitive, mature technology in order to achieve the RES share targets in 2030 and 2050 – if the scenario effectively occurs, the German policy framework will attain its goals in the sense that market forces will select CCGT as the source for flexibility. Another option is for the long-term goal of technological development and more thorough fossil-fuels phase-out. In this case, the German energy policy is not robust and will not induce the market towards investment in new, riskier technologies such as batteries for energy storage. Therefore, the robustness of the Electricity Market 2.0 under this scenario depends on goal priority setting.

7.3. Alternative Policy Instruments and Future Research

One of the policy options not analysed in this research is the use of demand-side management (DSM) to provide system flexibility. Similarly to the addition of generation installed capacity, the reduction of demand from a consumer increases the system

[8] Prices of both fuel and emission allowances are set at the lower-bound of the sensitivity analysis range, i.e. 30% lower than the reference values.

reliability (de Vries et al., 2017). Moreover, Laloux and Rivier (2013) argue that DSM reduces the investments needs in generation and transmission, and should be sought by policy-makers. The implication for this research is that, if consumers respond to RES availability and reduce their demand in moments of scarcity, then the requirement for flexible generation sources is reduced. Additionally, Zerrahn et al. (2018) suggests that flexible demand can substitute energy storage, provided that the price volatility is passed through to consumers. They can profit from the arbitrage of shifting their load from periods of higher prices to periods of lower ones.

One of the challenges with DSM is that demand for electricity is highly inelastic. In general, consumers have imperfect information about price in a timely manner and limited alternative options for the consumption of electricity. Historically, attempts to increase price elasticity had limited impact on consumers (de Vries et al., 2017). However, this is expected to change, with increasing awareness of consumers, developments of communications technologies and advent of smart-meters (Laloux & Rivier, 2013). Another challenge of DSM is that demand reduction has the same characteristics of a public good as increase of installed capacity, and it is prone to be undersupplied (de Vries et al., 2017). Without proper compensating mechanisms, demand response is limited to consumers that see advantage in the trade-off between electricity cost and welfare.

The Electricity Market 2.0 recognizes the potential benefits of demand participation to the power system. Three of its propositions address these challenges, Measures 6, 8 and 13. Combined, they open the balancing market for new providers and revise rules that are thought to restrict the participation of consumers in them. They also promote gradual introduction of smart meters (BMWi, 2015).

One metric that can be added to problem investigation to gain further insight is the Value of Lost Load (VOLL). It refers to the average consumer surplus that is lost when there is demand curtailment. Power markets are characterized by diminishing marginal utility of consumers, and so the VOLL varies among consumers, depending on the end use of electricity, time of day and amount of the curtailment. Nonetheless, there are methods to measure it as a single value for a group of consumers, given in EUR/MWh (de Vries et al., 2017; Ventosa et al., 2013; Zweifel et al., 2017). This can be used to compare the social welfare loss from demand curtailment with the cost of flexible generation sources. Additionally, this metric is interconnected with the idea of DSM, where consumers actively reduce their demand and can be compensated for it. These two elements can be researched further in light of the goals and results of this thesis.

Another relevant future research is to assess the importance of the cost criterion for generation firms in Germany. Considering their strategic behaviour in an oligopolistic market, the investigation of their propensity to invest also requires consideration of goals and resources other than generation costs. Once the comprehension on the firm level perception is more thorough, it can be used for an agent-based model in order to examine their interdependence and resulting emergent behaviours in the German energy transition.

Finally, future research can investigate the attractiveness of CCGT generation for other countries with fast growth of wind and solar generation. Cross-country comparison can help to validate the results of this thesis.

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Appendix A. Full LCOE Data Collection

This appendix contains in all the collected data for the calculation of the LCOE of CCGT generation.

Table 18. Capacity factor for CCGT generation in Germany and other countries, according to IEA and NEA (2015).

Germany		Other Countries	
Fixed value from 2013 to 2043	Sensitivity Analysis	Lower bound	Higher bound
85%	50%	35%	93%

Table 19. Current and expected capacity factor for CCGT generation in Germany, according to Kost and Schlegl (2018).

	2018	2020	2025	2030	2035
Lower bound	22,8%	22,6%	22,0%	21,5%	21,0%
Average	40,0%	39,4%	38,1%	36,7%	35,4%
Higher bound	57,1%	56,5%	55,1%	53,7%	52,4%

Table 20. Capacity factor for CCGT generation, according to ENS (2015).

	From 2016 to 2046
Fixed capacity factor	57,1%

Table 21. Capacity factor for CCGT generation, according to Agora Energiewende (2014).

	Low utilization	High utilization
2011 - 2033 average capacity factor	22,8%	45,7%

Table 22. Capacity factor for CCGT and CT generation, according to (EIA, 2018b).

	Conventional and Advanced CCGT	Conventional and Advanced CT
Plants entering operation in 2020, 2022 and 2040	87%	30%

Table 23. Data collected regarding typical installed capacity of CCGT power-plants, in MWi.

	(IEA & NEA, 2015)	(Kost & Schlegl, 2018)	(ENS & Energinet, 2016)	(EIA, 2018a)	(Konstantin & Konstantin, 2018b)
2013	500				
2017				429 - 702	404
2018		400	600		

Table 24. Data collected of CCGT power-plants lifetime, in years.

	(IEA & NEA, 2015)	(Kost & Schlegl, 2018)	(ENS & Energinet, 2016)	(Agora Energiewende, 2014)	(EIA, 2018a)	(Konstantin & Konstantin, 2018b)
2013	30			30		
2015			30			
2017						25
2018		30				
2020					30	

Table 25. Collected data of CCGT power-plants the energy conversion efficiency, in %.

	(IEA & NEA, 2015)	(Kost & Schlegl, 2018)	(ENS & Energinet, 2016)	(Agora Energiewende, 2014)	(EIA, 2018a)	(Konstantin & Konstantin, 2018b)
2013	60%			52% - 60%		
2015			59%			
2017						60%
2018		60%				
2020		61%	59%		52%	
2030		62%	61%			

Table 26. Collected data of natural gas carbon emission factor, in tonCO₂ / MWh$_{therm}$.

	(Kost & Schlegl, 2018)	(ENS & Energinet, 2016)	(Agora Energiewende, 2014)	(EIA, 2018a)	(Konstantin & Konstantin, 2018b)
2013	0,200		0,202		
2015		0,205			
2017					0,202
2020				0,181	

Table 27. Collected data of CCGT power-plants construction time, in years.

	(IEA & NEA, 2015)	(ENS, 2015; ENS & Energinet, 2016)	(EIA, 2018a)	(Konstantin & Konstantin, 2018b)
2013	2		3	
2015		2 – 2,5		
2017				2,5

Table 28. Collected data of CCGT power-plants overnight cost, in thousand EUR_{2017} / MW_i.

	(IEA & NEA, 2015)	(Kost & Schlegl, 2018)	(ENS, 2015; ENS & Energinet, 2016)	(Agora Energiewende, 2014)	(EIA, 2018a)	(Konstantin & Konstantin, 2018b)
2013	719			788 - 647		
2015			758 – 873			
2017						833
2018		760 - 1.045				
2020			853		869	
2030			805			
2050			776			

Table 29. Collected data of CCGT power-plants fixed O&M costs, in EUR_{2017} / MW_i.

	(Kost & Schlegl, 2018)	(ENS & Energinet, 2016)	(Agora Energiewende, 2014)	(EIA, 2018a)
2013			19.607 – 27.646	
2015		30.250		
2018	22.000			
2020		29.554		11.110
2030		28.041		
2050		26.225		

Table 30. Collected data of CCGT power-plants variable O&M costs, in EUR_{2017} / MWh.

	(Kost & Schlegl, 2018)	(ENS & Energinet, 2016)	(EIA, 2018a)
2015		4,54	
2018	4,0		
2020		4,44	3,13
2030		4,24	
2050		4,03	

Table 31. Collected data of CCGT power-plant projects discount rate, in real terms percentage.

	(IEA & NEA, 2015)	(Kost & Schlegl, 2018)	(ENS, 2015)	(Agora Energiewende, 2014)	(EIA, 2018b)	(Konstantin & Konstantin, 2018b)
2013	3%*, 7%, 10%			6% - 12%		
2015			4%*			
2017						6,5%
2018		5,2%				
2020					3,7%	
2022					4,5%	
2040					4,5%	

* Denotes a social discount rate.

Table 32. Collected data of natural gas prices, in EUR_{2017}/ MWh_{therm} for each operational year.

	(IEA & NEA, 2015)*	(Kost & Schlegl, 2018)	(ENS, 2015). Scenario 1	(ENS, 2015). Scenario 2	(ENS, 2015). Scenario 3	(Agora Energiewende, 2014)
2013	28 - 33		34,7	34,7	34,7	22,2
2014			25,7	25,7	25,7	22,5
2015			25,3	24,5	25,3	22,7
2016			25,4	24,8	25,7	22,9
2017			25,0	24,6	25,7	23,4
2018		21	24,6	24,4	25,7	23,8
2019			24,4	24,4	25,9	24,2
2020		25,1	24,2	24,4	26,1	24,6
2021			23,6	24,2	26,2	25,0
2022			23,2	24,2	26,4	25,5
2025		27,1	23,2	25,3	28,3	
2030		32,2	26,7	30,8	35,5	
2035		33,8	25,9	32,5	37,3	
2040			25,2	34,1	39,1	
2045			24,5	35,7	40,9	
2050			23,7	37,3	42,7	
2075			23,7	37,3	42,7	

*Given in a single fixed value to be used for every operational year.

Table 33. Collected data of emission right prices, in EUR_{2017}/ MWh_{therm} for each operational year.

	(IEA & NEA, 2015)*	(Kost & Schlegl, 2018)	(ENS, 2015). Scenario 1	(ENS, 2015). Scenario 2	(ENS, 2015). Scenario 3	(Agora Energiewende, 2014)
2013	3,9 - 4,4		0,9	0,9	0,9	1,6
2014			1,2	1,2	1,2	1,8
2015			1,4	1,4	1,4	2,2
2016			1,8	1,8	1,7	2,6
2017			2,1	2,1	2,0	2,9
2018		1,06	2,4	2,4	2,3	3,3
2019			2,8	2,8	2,6	3,7
2020		1 - 3	3,1	3,1	2,9	4,1
2021			4,3	3,4	3,0	4,4
2022			5,4	3,6	3,1	4,8
2025		2,5 - 6,5	8,7	4,2	3,6	
2030		4 - 10	14,3	5,3	4,3	
2035		6 - 14	17,1	6,2	5,0	
2040			20,0	7,1	5,7	
2045			22,8	8,1	6,4	
2050			25,7	9,0	7,1	
2075			25,7	9,0	7,1	

*Given in a single fixed value to be used for every operational year.