Technische Universiteit Delft
Delft, Spring, 2019

Competitiveness of Renewable Energy

An empirical study examining the relative cost of energy generation to determine the competitiveness of renewable technologies within the German electricity market.

Ole R. Hvalbye

Supervisors: Enno Schröder, Erik Wold

Committee: Cees van Beers, Hadi Asghari

Master Thesis, Sustainable Energy Technology, Energy Economics & Society

TECHNISCHE UNIVERSITEIT DELFT

Abstract

This thesis examines the competitiveness of renewable energy technology compared to conventional power generation methods by examining the relative cost of solar PV, wind, and coal. The findings of this analysis seek to answer the primary hypothesis:

> The unique application of Levelized Cost of Electricity (LCOE), entailing the manipulation of CAPEX and CO_2 variables, reveals the points in time and the exact LCOE values where it becomes cost competitiveness to switch from a coal asset to a renewable asset within the context of the German electricity market.

The results illustrate that cost competitiveness between new renewables (solar PV, onshore wind, and offshore wind) and coal in the German electricity market does cross at certain points. The research seeks to determine the precise scenarios under which new renewable plants are more cost competitive than existing coal plants. The LCOE calculation has been chosen as the methodology to estimate the relative cost competitiveness of these differing power generation methods, under predefined scenarios for both CAPEX-reduction for renewables and CO_2-price increase for coal. New assets are compared to existing assets; therefore, LCOE has been chosen in order to compare operational costs (OPEX) plus the capital cost (CAPEX) of new assets, with only the operational cost (OPEX) for existing assets. i.e. the investment cost for coal-fired assets is denoted as a sunk cost. This allowed for the development of a simplified framework to analyze an electricity-producing firm involved in an investment decision, whether a new solar or wind project or the continuation of an existing coal power plant.

The analysis of the current situation/base case scenario for Germany shows that the power production sector in the country currently suffers from a high degree of carbon lock-in, undermining Germany's ability to satisfy their international and domestic agreements related to the Paris Agreement and their own Coal phase-out plans. However, within the International Energy Agency's (IEA) *current policies scenario*, which considers the low-case for forecasted CO_2-price trajectory and estimated 10% CAPEX-reduction for renewables, we see that on a cost-only basis, theoretically, coal will no longer be competitive as soon as mid-2021. In contrast to the base case scenario, this indicates that lock-in does not exist, as scrapping coal plants in favor if commercial-scale solar PV and/or onshore wind project will be the more profitable option.

Regardless of how the future of energy policy will unfold, there is no uncertainty that the CO_2-price will increase with time. Thus, the business of coal-fired generation will become weakened,

reducing carbon lock-in in Germany and opening the door for policies which favour renewable power sources.

The resulting analysis illustrates that CAPEX-reduction has a surprisingly small effect on LCOE calculations for solar PV, and onshore and offshore wind, whilst the OPEX for coal-fired assets is significantly sensitive to variations in CO_2-price. It also identifies carbon lock-out within the current policy regime and confirms the existence of a number of *points of competitiveness* where the cost competitiveness of renewables will surpass coal under specific scenarios. Within the *current policies scenario* (which considers a 10% renewable CAPEX reduction) solar PV and onshore wind both exhibit a lower LCOE than coal at 0.135 and 0.140 USD per kWh respectively in 2021. Under the same scenario, offshore wind installations are assumed to be more expensive than the continued operation of existing coal plants within the forecast period. Within the *new policies scenario* (which considers a 15% renewable CAPEX reduction) solar PV, onshore wind and offshore wind all exhibit a lower LCOE than coal. Solar PV and onshore wind exhibit an LCOE of 0.140 and 0.138 USD per kWh in 2020, and offshore wind exhibits an LCOE of 0.168 USD per kWh in 2028. Lastly, within the *sustainable development scenario* (which considers a 20% renewable CAPEX reduction) new solar PV installations would have already become more competitive than coal at 0.175 USD per kWh in 2017, while onshore wind (among the cheapest sources of energy) is already more cost competitive than coal at the present time. The more expensive alternative, offshore wind, is forecasted to exhibit a lower LCOE than coal at 0.195 USD per kWh in 2020.

From a cost-only theoretical investment decision perspective, this study emphasizes the need to take into account the impact of decreased CAPEX for new renewable installations and increased CO_2-price (dictating OPEX) for existing coal-fired plants along with the theoretical points of competitiveness.

1 Introduction

On a cloudy day in December 2015, world leaders convened in Paris to do what had never been done – set a global precedent for addressing climate change. The resulting Paris Agreement established a set of guidelines for participating nations to transition away from fossil fuels in stages, in the hopes of stemming the tide of greenhouse gas emissions. The agreement, which became official on 4 November 2016, has driven a wave of low-carbon transition in nations across the world. It hopes to reverse the trend of rising temperatures, aiming for a global temperature increase of no more than 1.5 Celsius above pre-industrial levels (UNFCCC, 2018b). In a sign of agreement, the European Commission has acknowledged the importance of mitigating emissions to address climate change. In 2011, the commission announced Europe 2020, a detailed strategy for a resource-efficient Europe in line with the Paris Agreement. The plan presents "a roadmap" to aid the EU as it transitions "to a competitive low carbon economy" by 2050 (European Commission, 2011).

With an overarching precedent established, the 24th conference of the parties to the United Nations Framework Convention on Climate Change (COP24) was then held in Katowice, Poland in December 2018. COP24 ended in success by establishing a common framework which ensures that all the member states formulate climate targets, and carry out emission reductions while measuring and reporting progress via a common methodology, allowing for verification and comparison. COP24 also considered the questions surrounding the financing of emission cuts and climate adaptation in developing countries.

An important result of the climate negotiations in Paris was the implementation of the "Talanoa-dialogue", which is an international knowledge exchange to communally discuss where the world is situated relative to international climate goals. At COP24 this dialogue was codified with the aim of sending a clear message to all involved parties, underscoring the necessity of implementing more ambitious emissions reductions by 2020 (UNFCCC, 2018a).

The aforementioned policy planks highlight that policymakers, politicians, and society as a whole have recognized climate change as a serious issue which should be dealt with urgently. The EU Roadmap and UN Paris Agreement are two examples depicting the increased political will and public focus on decarbonizing the world economy. Both point towards international readiness for emission reduction, driven by the unfortunate consequences of climate change as seen in increased social and ecological costs, such as negative health effects and environmental degradation.

Decarbonization and climate change alleviation are meant to inhibit or reduce carbon dioxide emissions. Methods for decarbonizing the power sector include: deploying renewable energy (RE) technologies, altering power intensive consumer actions, adopting more efficient carbon-based power generation methods, and implementing efficiency improvements on existing carbon-based power plants (UN Environment, 2018).

Due to high system costs, such as grid updates, balancing capacity and short-term storage capabilities, RE’s intermittent nature tends to impose additional costs for the end user in electricity markets, which are not perfectly suited for fluctuating power producing technologies. Examining the issue in closer detail, this report considers the interesting case of Germany’s energy market transition to RE. Given its sheer size and populace, Germany is a natural leader in the European Union’s industrial, economic and energy affairs. Considering the country’s vast industrial complex with substantial investments across energy-intensive manufacturing, certain implicit friction naturally opposes any political efforts in the country that may drive up energy prices – an assumed risk of implementing large-scale intermittent RE. Additionally, consumer adoption of a less carbon-intensive lifestyle tends to trend in tandem with the economic activity level.

In the context of improving energy efficiency, the principle of pricing externalities – such as carbon taxes or tradable emission permits – are demonstrably effective mechanisms. Previously, these instruments were not granted equal validity as direct political RE promotion, such as subsidies (Borenstein, 2012). However, the efficacy of pricing externalities to motivate energy efficiency was recently affirmed at COP24 (UNFCCC, 2018a). Within this renewable energy ecosystem is the complex issue of RE technology deployment, a primary driver of decarbonization. And underpinning the competitiveness of renewables, and energy technologies, in general, is the precept that the market will be dictated by the relative cost of power production.

In the past, large-scale implementation of unsubsidized RE has consequentially imposed significant costs on investors and consumers, whilst heavily subsidized RE has inflicted large costs upon states and governments. Thus, RE implementation often succumbed to the criticism of being economically expensive, which largely disincentivized the decarbonization of the energy mix. Thankfully, the last decade has changed this, as new technologies and greater efficiency has brought about a turning-point for RE cost competitiveness, and therefore investment.

In 2016 RE passed an important inflection point, when for the first time RE dominated global installed capacity, overtaking 55.3% of the energy market (excluding large hydro projects of < 50MW). Solar gigawatts accounted for 26% (75 GW) of new installed capacity, more than any other energy technology, followed by coal and onshore wind with 24% and 18% respectively (FS, 2017). Yet, curiously, investments in RE decreased by 23% compared to the previous year.

These developments can be understood as the result of a number of factors. It is clear that RE quickly became cost competitive through the rapid reduction of costs associated with green power production. In fact, in some favourably situated areas, solar power projects have been proven more affordable than incumbent carbon power generation. This shift has not always received a positive response, sometimes leading to protective policy measures around the coal and gas industries, therefore causing regional slowing of RE diffusion (FS, 2017).

It should be noted here that energy systems are, by definition, socio-technical systems. Dominant socio-technical systems must be deemed favourable by participants due to more than just technological and economic competitive advantages. Through the socio-technical lens, we see why established energy systems retain dominant positions, even though low-carbon and higher efficiency technologies are available. As a result, preliminary technological choices have created social, technological and institutional path-dependency. This dependency, termed carbon lock-in, has chained industrial economies to existing fossil fuel-based technology (Unruh, 2000).

In the German electricity market, carbon-based and renewable technologies are compared using a standardized metric, the LCOE. LCOE measures the cost of a power generating plant per MWh of electricity, produced over the lifetime of the generating asset. The LCOE has been widely acknowledged as a suitable methodology for comparing the cost of different power generation technologies. In this project, LCOE will be used as a tool for comparison due to its key advantages and overarching concepts (DOE, 2016). LCOE measures lifetime cost divided by energy production, calculates the present value of the total cost of building and operating a power plant over an assumed lifetime, and allows for the comparison of different technologies (for example solar, wind and coal) of dissimilar lifespans, project size, capital investment, operational cost, risk, return, and capacities.

An essential step to overcoming carbon lock-in is the decrease in renewable LCOE. The lower the LCOE, the more cost and market competitive RE generation will become. And with increased market incentivization, the RE diffusion rate will rise. RE diffusion is directly related to overcoming the carbon lock-in effect in an electricity market, and therefore it is clear that decreasing renewable LCOE is an essential step in any green transition.

Preliminarily LCOE analysis conducted in tandem with Rystad Energy verifies that unsubsidized renewable energy technology, such as large-scale solar and wind projects, are on average cheaper than coal projects in Germany, paving way for renewables to become the natural choice for future investments in power generation (Husebye, 2018). However, directly reducing the cost of deploying and producing power from RE technologies is not enough to overcome the lock-in effect of cheap, established conventional power producing technologies, such as coal-fired power plants. The high cost of shifting from established infrastructure (system cost), combined with political uncertainty, as well as coal's dominant position in the electricity market are all factors which inhibit the deployment of new energy technologies.

Given the additional costs and political uncertainty surrounding RE deployment in Germany, this report will focus on comparing operative/existing coal-fired power plants with new solar and wind projects in the country. This comparison will be possible by quantifying and comparing LCOE in order to forecast a variety of possible outcomes by manipulating key variables. Utilizing this methodology will provide a deeper understanding of the timeline and conditions necessary for RE projects to become cheaper than existing coal plants.

Analysing the scenarios in which new renewable plants become more cost competitive than existing coal plants provides the key to determining when renewables will be able to overcome the carbon lock-in of existing fossil fuel systems. The RE diffusion rate can be estimated by comparing the operational cost (OPEX) plus capital cost (CAPEX) of new investments using only the operational cost (OPEX) of existing energy technology. This comparison underlines the presence of a knowledge gap in the existing literature. Hence, further research is needed in order to formulate a significant cost comparison between new investments within wind and solar, and existing coal-fired power plants with high levels of operational expenses (OPEX), but sunk investment cost (CAPEX).

The LCOE comparison between solar, wind and coal is performed by computing a sensitivity analysis, which means manipulating predefined sets of variables within the LCOE equation. The sensitivity analysis in this report examines the sensitivity of the economic variables CAPEX and CO_2 price. CAPEX for new solar and wind installations is acknowledged as a major part of the cost of implementation, and thus dictates the competitiveness of emerging technologies. Conversely, the CO_2 price is recognized as an important factor in the total operational cost of a coal power plant. The sensitivity analysis in this paper includes CAPEX reduction scenarios for solar and wind, and CO_2 price increases for coal in order to determine the level of CAPEX decrease and CO_2 price increase required for new wind and solar installations to reach cost competitiveness compared to old coal-fired power plants within the German electricity system.

The background and literature review section presents historical statistics from Rystad Energy's database and additional research, dating back to the early 70s. This era established the foundation of what has now become Germany's Energiewende and the anti-nuclear movement. In order to deeply understand the development of the German electricity market, cumulative installed capacity from all energy sources within the country from 1970 to 2018 are illustrated. Significant findings will discuss the results from the levelized cost analysis. This includes examining data from the early 2000s to the present, the current base case for the year 2018, and the IEA's Policies Scenarios which dictate CO_2-price estimates for the year 2020, 2030 and 2040. Therefore, the project includes data sets from Rystad Energy's databases from 2000 to 2040. The data includes data points per asset, which correspond with the variables in the LCOE equation, namely expected asset lifetime, and production and economic variables such as capital cost (CAPEX), operational cost (OPEX) and discount rate.

Additionally, the literature study in chapter 2.2.1 has demonstrated that carbon lock-in is a well-known concept and a widespread issue in today's energy systems. This is an issue Germany knows well, as its dependency on fossil-fuel generated electricity has presented tremendous difficulties in transitioning to green energy, even as the country is considered a global leader in terms of both recently deployed RE technology and energy policies.

Lastly, the reporting framework is developed on the basis of Carbon Lock-in and Path Dependence in energy systems, and as mentioned, the data is extracted and analysed from Rystad Energy's plant-level data for the global upstream power market (PowerCube). The methodology includes computation and modelling of LCOE estimates for different power producing technologies, including solar, wind and coal.

The main research question asks, what points in time and what are the exact LCOE values where it becomes cost competitive to switch from a coal asset to a renewable asset within the context of the German electricity market?

This question will be examined through the manipulation of CAPEX and CO_2 variables within the LCOE equation by answering the following sub-questions:

- How sensitive is the LCOE of renewable assets to a decrease in CAPEX, and how will this affect the cost competitiveness of the technology?
- How sensitive is the LCOE of coal assets to an increase in CO_2 price, and how will this affect the cost competitiveness of the technology?

Section 2 of this report describes the policy, environmental and market background of both renewable and coal-fired capacity. Furthermore, it reviews recent publications that have sought to demonstrate and quantify carbon lock-in and LCOE values of electricity generation respectively. Section 3 presents essential data and describes the approach used to provide an assessment of the LCOE comparison. Section 4 presents the results of the LCOE calculations and resulting comparisons and discusses key findings as well as shortcomings. Section 5 summarizes concluding points, while sections 6 and 7 offer the bibliography and the appendix.

2 Background & Literature Review

The existing literature which expounds upon the energy situation in Germany has described the present situation in terms of "carbon lock-in". Unruh (2000) defines carbon lock-in as systematic processes which have developed a path dependence in energy systems, through the creation of technological lock-in of carbon-based energy, thus undermining alternative carbon-saving technologies, especially renewable energy. Germany is a particularly poignant example of a country suffering from carbon lock-in, as they have a long history of carbon dependency dating back to the industrial revolution. Out of this carbon lock-in environment, Energiewende emerged as an alternative pathway for powering Germany's future. Energiewende seeks to overcome the problem of carbon lock in by replacing fossil and nuclear power generation with less CO_2 intensive and renewable sources. Consequently, aiming to become carbon neutral by the year 2050.

2.1 Background

European Commission (2011), "A roadmap for moving to a competitive low carbon economy in 2050", emphasizes the need for renewable energy (RE) technological innovations and actions for strengthening lucrative investments in new energy solutions. Additionally, it expresses the need for an increased focus on energy efficiency policies (Energy Efficiency Plan). In order to restrict the temperature-increase to below 2 degrees Celsius, and successfully transform the EU into a competitive low carbon economy - the roadmap represents an objective of reducing the 1990 emission levels of greenhouse gas by 80%, by 2050, within all sectors.

More than a quarter of global emissions originate from the burning of coal, natural gas, and oil for electricity production. This represents the largest single source of global greenhouse gas emissions (EPA, 2014). Due to this, electricity production is recognised as playing a key role in decarbonizing the economy. The roadmap, European Commission (2011), estimates that the power sector will eliminate nearly all carbon dioxide (CO_2) emissions (93-99%) by 2050. Additionally, electricity usage is rapidly becoming an alternative to fossil fuels in both the transport and heating sectors. This underlines the future growth potential of the power generation sector and the vast decarbonising opportunities within transport and heating. European Commission (2011) concludes that the 2050 target for the power sector would be feasible given the implementation of sufficient carbon price signals, long-term predictability, energy taxation, and technological support mechanisms.

However, there is not only a common engagement between stakeholders and a political motive striving for decarbonization. Presently, the carbon-based economical system already has a substantial positive industrial and economical repercussion upon society, especially beneficial to the working class. Even though ruinous environmental fallout is widely known by decision makers, the fear of harmful economic outcomes is strengthening the effect of carbon lock-in. Hence, rooted opinions, political calculations, habits, and cultural values demonstrate an influential role in the formation of energy policy (IPC, 2018).

2.1.1 CO_2 price and the push towards renewables

Globally, renewable energy investment is dominated by solar and wind. It is predicted that these two sectors will govern future new investments in renewable energy within Germany (FS, 2017). In 2017, wind and solar energy accounted for a third of the electricity generated in the country, while the largest share (40%) of electricity generation was from coal. Moreover, a large share of the coal power plants is fired with the most polluting type of coal, namely lignite (brown coal). When viewed in relation to the projected rise of CO_2 prices in Europe, this has increased the awareness amongst the public, investors, and politicians. Newly conducted research by the Carbon Tracker Initiative demonstrates that the price of CO_2, which is traded under the European Emissions Trading System's (EU ETS) cap-and-trade scheme, could average to €35-45 per tonne CO_2 between 2019 and 2023. As of May 2019, the carbon price stands at **€25 per** tonne **CO_2**, already demonstrating a clear effect upon the German electricity market. The price range of €35-45 per tonne CO_2 could result in replacements of coal-fired plants into gas-fired plants, emitting less CO_2 per kWh. Consequently, this will contribute to Germany's Energiewende policy, replacing fossil and nuclear power generation with less CO_2 intensive and renewable sources (CT, 2018). On the other hand, Germany's medium-term dependence on coal has increased in the wake of the decision to shut down all nuclear power plants by 2022. This is a necessity for maintaining the security of supply in a period of nuclear decommissioning (Bloomberg, 2017).

Power production from gas is considered to be a bridge technology and an important aspect in the future for Germany pursuing a low carbon economy. However, in the short-term, it is unlikely that gas-fired power plants will substitute coal-fired power plants. Therefore, examining the current energy situation, which includes: nuclear phase-out; abundantly available cheap coal; and moderate CO_2 prices, a cost comparison of wind, solar and coal demonstrate to be a natural choice considering Germany's existing energy mix. Still, it is worth mentioning the potential of discussing whether or not solar and wind are suitable technologies for substituting coal plants, given their intermittent nature and different operating characteristics. Chapter 3, section 3.2.2.9.1 will discuss this further.

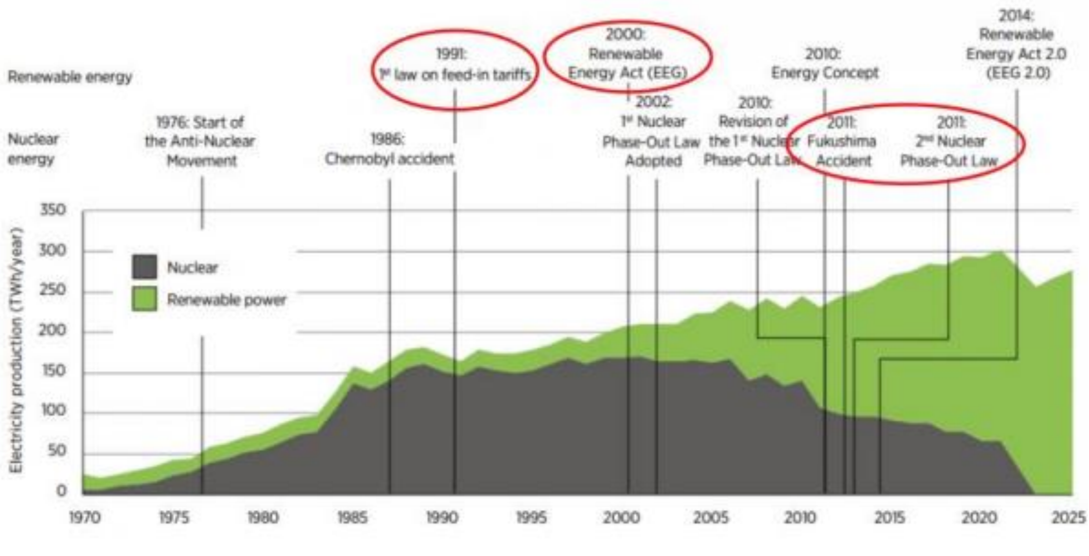
2.1.2 Energiewende

Energiewende (energy transition) is Germany's approach in order to cope with damaging CO_2 emissions from the power generation sector. The strategy does not include emission-free nuclear power, which is to be shut down by the year 2022, due to political motivations (Rystad, 2017).

The decision to revolutionize the energy system has been motivated by public interests, political support and through the commitment to the Paris Climate Agreement in 2016. Germany is Europe's most populated country, which is aiming to become carbon neutral by the year 2050. The development is closely monitored by nations worldwide, due to the country's origin and the present high dependence upon fossil-fuel generated electricity.

2.1.2.1 History and milestones

Figure 2.1: Important policies and historical events of Energiewende



Source: (Kuittinen and Vetle, 2018)

Figure 2.1, illustrates the most significant policies and historical events which have shaped the Energiewende (Kuittinen and Velte, 2018). An anti-nuclear movement and related politics grew increasingly strong in the period between 1973 and 2011. The term "Energiewende" was first used in conjunction with the introduction of the German Green Party, founded in 1979, and their key aspirations to shut down nuclear plants and the promotion of renewable energy. The

Chernobyl disaster in 1986, significantly strengthened the movement. In 1990 the *Nuclear phase-out #0* was initiated, this caused the shutting down of East Germany's (GDR) only two reactors with the reunion of Germany. The same year, the Federal Cabinet introduced the first emission reduction target, which included 25-30% less CO_2 emissions by 2005, relative to 1987 levels. The following year, in 1991, new legislation introduced feed-in-tariffs for RE promotion, for the first time. Further political motivation was triggered by the *Kyoto Protocol* between 1997 and 2015, dictating Germany – the world's sixth largest emitter at the time – to cut CO_2 emissions. In the year 2000, fixed feed-in tariffs and grid priority for RE was introduced through the *Renewable Energy Act*, as well as the initiation of the *Nuclear phase-out #1*, which introduced a phase-out plan for around 2022. EU set the 2020 climate target in 2007, this included: 20% electricity generation from RE; 20% reduction in greenhouse gases; and 20% efficiency improvements. In 2010, the nuclear phase-out came to a hold, when the conservative party, CDU, decided to cancel the plans. Additionally, the government introduces the *Energy concept*, this set out fixed climate and RE targets for 2020 and 2050. However, 2011 marked an important year for the anti-nuclear movement, in response to the Fukushima disaster, the *Nuclear phase-out #2* was set into action when Angela Merkel announced the new nuclear phase-out by the year 2022. This statement was heavily supported by the majority in the parliament (CEW, 2017a).

Prior to 2011, the focus was shifted towards RE promotions. In 2014, the German Renewable Energy Act (EEG), reduced the feed-in tariff, and initiated an auction system for solar PV capacity, as well as introducing a detailed plan on how to achieve the 2020 climate targets. Germany's ambitious energy transition goals were questioned in 2015 when BMWI (Federal Ministry for Economic Affairs and Energy) presented the "Energiewende monitoring report", FMEAE (2015). This stated that even though lucrative support mechanisms were firmly in place, the 2020 emission reduction goal was likely to be significantly off target. In 2016, commercial, profit maximising companies were seeing opportunities within utility spin-offs. Hence, utilities E.ON and RWE were separating the RE portfolio from conventional fossil fuel operations. This, in turn, demonstrated the importance of their RE investments and future opportunities in this market. Meanwhile, the Federal government initiated its *Climate Action Plan 2050*, a framework for decarbonizing the German economy, in order to reach the 2050 climate goals. The framework presented details for sector-specific greenhouse gas emission reduction (CEW, 2017a).

2.1.2.2 Drivers and challenges

The shift from fixed feed-in tariffs to auctions for renewables entered into force in 2017. Policymakers decided that the RE sector is mature enough to reduce the highly lucrative support mechanisms and promote free competition. EEG aimed to expose RE generation to market forces, thus reducing the cost for consumers. 2017/2018 policy and newer legislation aimed to limit the amount of new renewable capacity that can be built each year. However, the legislation was highly debatable. Industry and energy companies saw this as a good approach, which would promote the energy transition at a more realistic and economically optimal pace for the involved stakeholders. The RE lobby, experts and Green Party participants expressed their concern, by stating that it would result in Germany missing its climate targets, thus deceiving the collective essence of the Energiewende in an effort to support business and industry. This offset between all involved parties was recognised as constituting a major future challenge. This challenge was composed of deciding what kind of strategy to adopt in order to satisfy the stakeholders, whilst simultaneously taking care of value creation, national and international agreements and public interest (Amelang, 2016).

In January 2018, the Directorate-General for Research and Innovation in the European Commission developed an in-depth case study, evaluating the Energiewende. The following table summarizes the most significant drivers and challenges (Kuittinen and Velte, 2018).

Table 2.1: Drivers and challenges related to the Energiewende

	Drivers	Challenges
Political	• Strong public and political agreement on Energiewende goals. • International climate change mitigation plan.	• Multi-level governance might lead to ineffective decision-making processes.
Economic	• Requirement for energy imports. • Scarcity and price development of conventional energy sources. • Creation of new domestic industry. • Decentralized ownership of the energy system (prosumers)	• The overall cost of the energy transition. • A rapid increase in electricity prices due to the EEG surcharge for renewable energies. • Nuclear and coal phase-out has also destroyed jobs in the conventional energy sector.
Societal	• Anti-nuclear movement since 1970s. • Fear of Climate change.	• Elevation of electricity prices may in the long-run erode public support.

	• Strong public support regarding energy transition goals.	
Technological	• Technological leadership and pioneering work in renewable energy technologies.	• Grid infrastructure capacity and digitalisation of energy transmission. • Energy storage technologies.
Legal	• Nuclear phase-out law. • European directives and regulation related to climate and energy.	

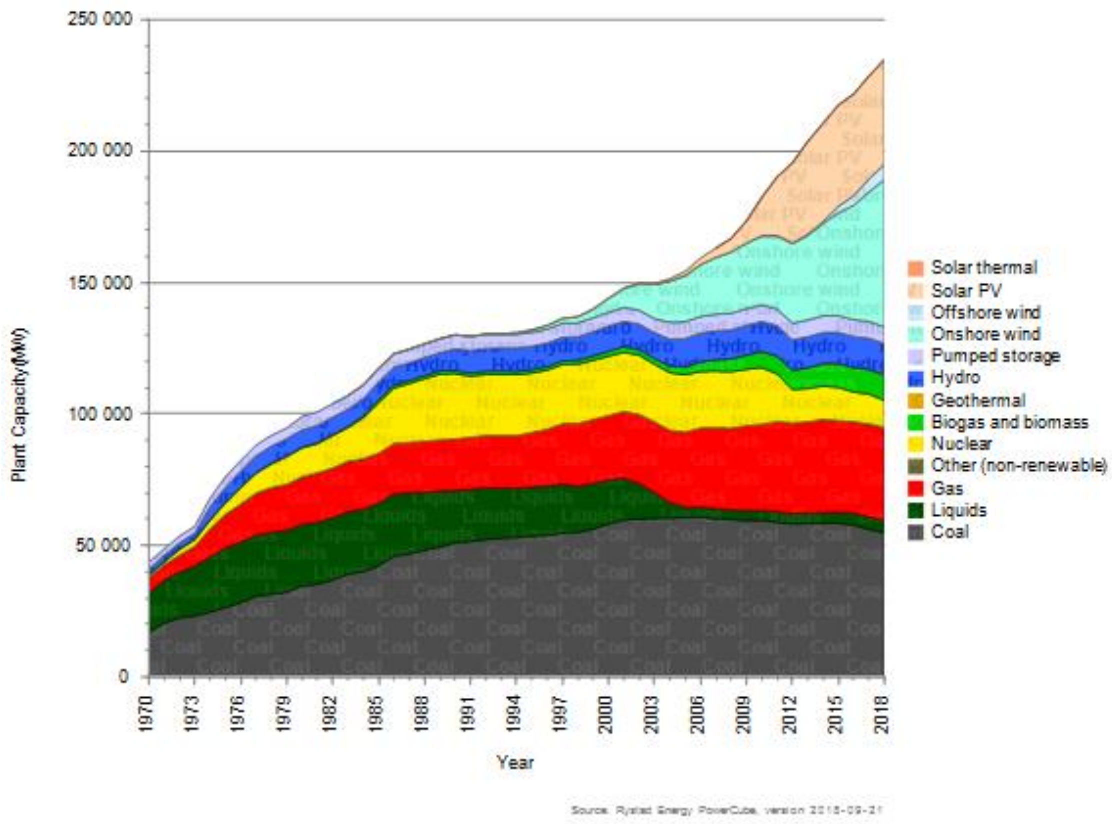
Source: (Kuittinen and Vetle, 2018)

The most significant challenges of any modern energy system include ensuring a reliable, economical and environmentally friendly energy output. These barriers also constitute the foundation of the Energiewende. "The energy concept" from BMWI (2010), states the following: "a central political goal for our energy system of the future: Germany should be one of the most energy-efficient and environmentally friendly economies in the world, with competitive energy prices and a high level of prosperity". This statement underlines the key goals of the Energiewende, namely: environmental sustainability, energy imports reduction, technological development, and economic growth.

2.1.2.3 Outlook

The majority of the opportunity in terms of emission-reduction is contained within the power sector. Today, almost half of the electricity produced in Germany originates from RE technologies, where most are generated by solar and wind, due to their generous governmental financial support (Fraunhofer, 2018). Additionally, since the implementation of the Renewable Energy Act 2.0 (EEG 2.0 – 2014) the installed capacity has been dominated by renewable sources since 2015.

Figure 2.2: Cumulative installed capacity in the German electricity market



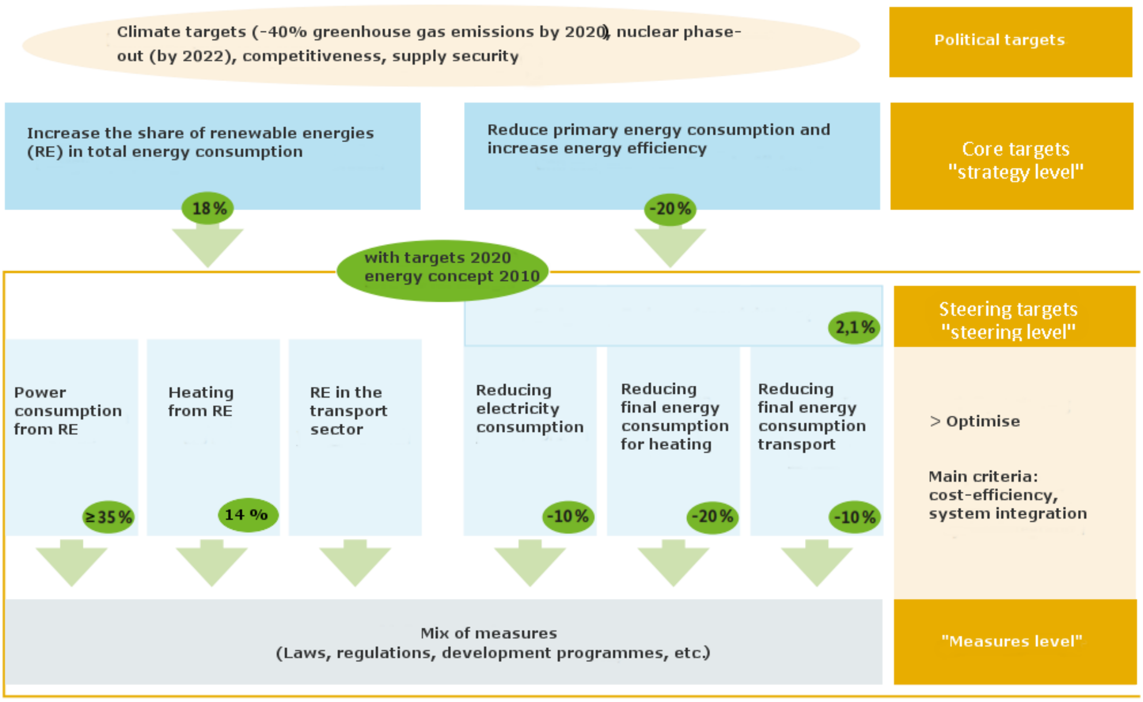
Source: (Rystad, 2018)

Figure 2.2 is an excerpt from Rystad Energy's upstream power-market database (PowerCube). The figure illustrates that the net installed power generation capacity in 2018 was led by onshore wind (56.1 GW), followed by coal (54.9 GW) and solar (39.8 GW). In the same year, a decline in the installed capacity of anthracite (hard coal) power plants, drove a 1.2 GW reduction in coal capacity, since 2017. Germany is currently the biggest producer of lignite (brown coal) in the world but has decided to close the last anthracite mine (Prosper-Haniel) in December 2018 (DW, 2017b).

In order to meet an increase in demand whilst maintaining the security of supply from non-variable sources, the balance in 2018 was performed through maintaining a high capacity of natural gas (35.2 GW). Even though natural gas is a more expensive resource to burn (increasing the cost for consumers), it demonstrates significantly reduced CO_2 emissions compared to coal. Natural gas has a CO_2 emission factor (kg/GJ fuel) of 57, compared to 94 for coal (DEA, 2015). The detailed information regarding CO_2 emission factors and a specific energy for different coal feedstocks is discussed in chapter 3, section 3.2.2.1.

2.1.2.4 Status

Figure 2.3: Germany's Energiewende targets



Source: (BMWI, 2016)

The chart in figure 2.3, illustrates Germany's RE and emission targets, published in the latest Energiewende Monitoring Report, BMWI (2016) from the federal environment ministry. The illustration demonstrates the structure of the individual goals of the Energiewende, differentiating between target levels including political targets; core targets (strategy level); steering targets (steering level); and measures level. The core objectives describe the central strategies of the Energy concept, aimed at advancing the energy transition (Energiewende). These objectives include expansion of RE; reduction of primary energy consumption; and increasing energy efficiency.

However, despite large ambitions and actions, Germany is facing challenges in realising its short-term emission targets (steering targets). This is mainly due to the medium-term dependence on lignite and anthracite, caused by decommissioning the country's large share of nuclear power. Consequently, this underlines the current existing carbon lock-in effect in the German electricity market (CEW, 2017b). On the other hand, the long-term situation looks different. In January 2019, Energiewende took a significant step towards becoming a reality when Germany's coal exit commission announced its benchmark for phasing out coal-fired power stations by 2038. Thus, opposing the fear of an economic downfall for the mining industry.

2.2 Literature Review

In this section, the major concepts, points, and outcomes of carbon lock-in and LCOE are discussed within the existing literature. The concept of path dependence in energy systems, namely carbon lock-in, is presented and its effect on RE technology is examined. Subsequently, the cost characteristics of three different electricity generation technologies will be illustrated through the application of the LCOE methodology.

2.2.1 Carbon Lock-in

2.2.1.1 Reason for lock-in

The global energy supply, transformation, distribution, and consumption system is the biggest existing infrastructural network, reflecting tens of trillions of dollars of investments and two centuries of technological development. These energy systems are also supported by a similar complexity of co-developed institutions, policies and consumer preferences (Smil, 2010). As much as 82% of the worldwide energy supply originates from fossil fuel sources, emitting damaging CO_2 emissions (IEA, 2017).

The immense scale of investments and physical assets within energy systems, as well as associated economic, cultural and political effects are limiting the diffusion of new technologies, new institutional mindsets and changing consumer behaviour. Consequently, this steers global economies into a path-dependence track, known as the lock-in effect. i.e. preliminary conditions, good economic returns for existing assets, and social and individual behaviour constrain the innovation and competitiveness of low-carbon alternatives (Seto *et al.*, 2016).

2.2.1.2 Carbon lock-in literature

For the first time in the year 2000, Unruh (2000) introduced the term *carbon lock-in*. Unruh's paper primarily presents systematic processes which have developed a path dependence in energy systems, through the creation of technological lock-in of carbon-based energy, thus undermining alternative carbon-saving technologies, mainly RE. Unruh (2000) demonstrates that despite the existence of low-carbon and highly-efficient technologies with economic advantages, established energy systems still retain a dominant position. Thus, creating a social, technological and institutional path-dependence. This dependency, termed carbon lock-in, has tied down industrial economies into fossil fuel-based technologies, especially within the electricity and heat production sectors - accounting for more than a quarter of global greenhouse gas emissions (IPCC, 2014).

Unruh (2000) demonstrates that the dependency, hence the barriers of RE diffusion, are underpinned by a “Techno-Institutional Complex” (TIC). The TIC notation is establishing a theory, giving both technological systems and governing institutions the blame for the carbon lock-in effect.

The same TIC aspect presented by Unruh is considered in Schmalensee (2012). ”Energy Decisions, Markets, and Policies” by Richard Schmalensee include three main aspects of how former energy decisions shape future decisions, thus emphasizing the importance of historical decisions.

First, the *cost of durable capital* (infrastructure) is highly relevant in most conventional energy technologies and systems. Meaning, energy infrastructure, and technology is vastly capital intensive and lasts for a long time. To some extent, RE technology retains similar characteristics. i.e. also, being highly capital intensive. Replacing conventional technologies with new energy technologies means that there is usually a replacement of assets that is capital intensive, with other assets that are also capital intensive. This fact alone makes it difficult to perform a change, thus abating the diffusion rate of new energy solutions, knowing that the new investment will also require a significant upfront cost.

The second aspect concerns how *political uncertainties* are factors which inhibit the deployment of new energy technology. Considerable changes in policy regimes tend to have a very disruptive outcome. Therefore, introducing substantial policy changes in political systems is not a simple process. Once a policy is implemented in a political system, it demonstrates a tendency of policies becoming locked-in. Schmalensee demonstrates an example founded upon the Clean Air Act (CAA). CAA is a federal law passed by EPA in 1970, devoted to the regulation of air emissions, in order to protect public health and welfare (EPA, 2018). The U.S. Governments Environmental Protective Agency (EPA) is responsible for setting standards for new electricity generation plants. In 1970 the ‘New Course Performance Standard’ was set in place by the CAA. Since 1970, it has been experiencing vast technological efficiency improvements within power generation, as well as increased availability of low-carbon technology, with low-cost characteristics (IRENA, 2017). Moreover, the unfortunate consequences of air emissions have been granted with more focus, both from a scientific, and a socially based perspective. These developments and problems have been known since the passing of the act, causing the discussion of changes and proposal of remedies. Despite this, the architecture of the CAA has remained unchanged since the 1970s. This is mainly a result of the established bureaucracy, states being related to the known, and the uncertainty on how alternatives would work (Schmalensee, 2012).

The third aspect includes the concept of *influenced interactions*. This states that path dependency could be triggered by arbitrarily made choices, which guide the user onto a path involving positive interactions, thus keeping the user on the same path. An example of this would be, chain events resulting in a specific path due to the occurrence of positive repercussions: A conventional energy system has a workforce and a technology associated with it. Thus, related institutions, taxation codes, and benefit systems are created around the employers or the implemented technology. As a result, neglecting the risk associated with performing policy changes (second aspect), would render it highly difficult for the rest of the system to change given the existing positive interactions (Unruh, 2000).

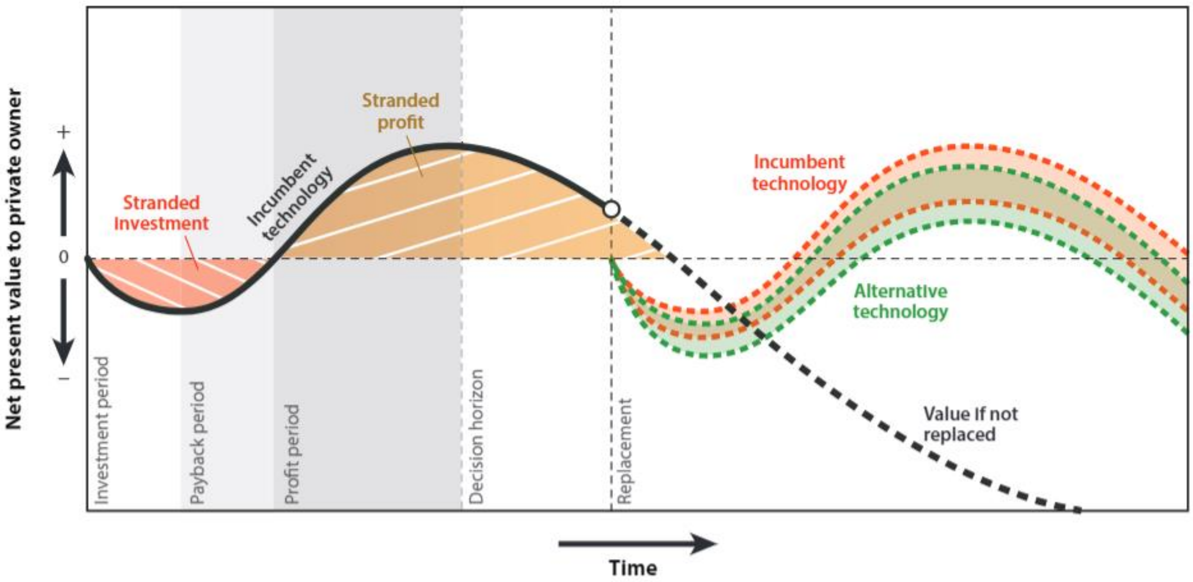
Similarly, as with Schmalensee (2012), most of the existing literature concerning carbon lock-in is based on the preliminary findings by Unruh (2000). A more extensive report, involving Unruh as a co-author, is Seto et al. (2016). "Carbon Lock-in: Types, Causes, and Policy Implications" conceptualize three major types of carbon lock-in, which demonstrate similar characteristics to the Schmalensee (2012) framework:

1) *Infrastructure and technological* lock-in, which directly influences the choice of deployed technology;
2) *Institutional* lock-in, concerning politics, which is related to governance and decision making, influencing both the power production and consumption pattern in an electricity system;
3) *Behaviour* lock-in, which is associated with the end-user consumption behaviour, i.e. consumers' social and individual habits and norms related to consumption.

Seto et al. (2016) also emphasize that it is important to consider how the three main types of carbon lock-in collectively strengthen the effect of carbon dependency. Their collective inertia is demonstrated, hence, changes in one type influence the development in the other types, resulting in either positive or negative repercussions.

The section concerning i*nfrastructure and technological* lock-in demonstrates key points in order to lock-out from either infrastructural or technological lock-in, this is worthy of particular consideration. Breaking out of the lock-in effect depends upon the following: assets and systems durability, estimated economic and technological viability, the cost associated with replacing assets and systems, and existing alternatives (Seto *et al.*, 2016).

Figure 2.4: The net present value of an energy asset



Source: (Seto *et al.*, 2016)

Figure 2.4, illustrates the lifetime value of a theoretical energy asset, a typical asset demonstrates a long lead time. Hence, a high up-front investment, followed by later-stage payoffs, which offsets a significant sunk cost. The net present value (NPV) is represented by the black curve. The NPV is negative and decreasing before the *profit period*, illustrated in dark grey, thus, paying back the initial investment. After this, the O&M cost incurs a depreciation of the generating profits. This period is denoted as the decision horizon, thus being the time-period within which the asset's future prospect is considered. At this time, the owner needs to decide whether to replace or modify the existing technology. The decision is taken based upon the background of expected future costs, policies and other risk factors which could strengthen the lock-in effect. The dashed black line demonstrates the development of the NPV given neither replacement nor modification, resulting in significant running expenses. However, a too early replacement generates lost value. The lost value could include the *stranded investment* (unpaid capital cost) and/or *stranded profits* (expected operating profits), depending on how early the asset is replaced. In conclusion, figure 2.4 indicates the importance of cost and profits relative to the lifetime of the asset, thus having a large influence on decisions, in turn affecting carbon lock-in (Seto *et al.*, 2016).

Another aspect worth mentioning is how the existing global carbon-intensive infrastructure affects the climate going forward. Davis et al. (2010) have developed a comprehensive study which is estimating future CO_2 emissions and climate change from existing energy infrastructure. As disused in Schmalensee (2012), energy and transportation infrastructure last for a long time, Davis et al. (2010) argue that the current operational long living technologies can be expected to contribute substantial CO_2 emissions over the next 50 years. It is mentioned that an early decommissioning of existing infrastructure or an extensive installation of Carbon Capture and Storage (CCS) technologies is necessary to overcome the carbon-intensive infrastructural inertia. Davis et al. (2010) quantify and presents scenarios reflecting direct emissions from existing energy and transportation infrastructure, while also presenting climate models of the warming commitment of the emissions. i.e. if all existing CO_2-emitting technologies lived out their lifetime, while no new CO_2-emitting technologies where built - what CO_2 levels and global mean temperatures would we then experience? Cumulative future emissions are calculated to be 496 gigatonnes of CO_2 from the combustion of fossil fuels from 2010 to 2060, resulting in mean global warming of 1.3 Celsius above pre-industrial levels. The author concludes that “these conditions would likely avoid many key impacts of climate change” and therefore “the most threatening emissions have yet to be built. However, CO_2-emitting infrastructure will expand unless extraordinary efforts are undertaken to develop alternatives” (Davis et al, 2010).

Lehmann et al. (2012) emphasize that the implementation of renewables is key for climate change mitigation, while also forming an important area of the European climate strategy going forward. As underlined in Schmalensee (2012), Lehmann et al. (2012) also stress how technological, economic and institutional patterns of energy systems favour the use of carbon-intensive sources, while hampering the implementation of renewable energy technologies. Consequently, questioning whether or not existing renewable energy promoting policies have been designed to properly promote carbon lock-out. The author highlights the existence of several shortcomings: while there is a wide range of policies targeting power generation, the EU lack addressing barriers associated with electricity grids, storage capabilities, and electricity demand. Additionally, implementation of policies has been disintegrated among the European countries. Taken this into consideration, Lehmann et al. (2012) conclude that “national policies should be embedded into integrated EU-wide planning of renewable energy systems with overarching energy scenarios and partially harmonized policy rules” (Lehmann *et al.*, 2012).

Erickson et al. (2015) have developed an approach to assess, “The speed, strength, and scale of carbon lock-in” for carbon-intensive assets in the power production, building, industry, and transportation sectors. The paper emphasizes that carbon lock-in is globally greatest for the following technologies in descending order: coal power plants, gas power plants, and fossil-fuelled vehicles. This underlines the importance to evaluate coal-fired generation and its costs going forward. The author concludes that assessing carbon lock-in “may be of particular relevance to policymakers interested in enhancing flexibility in their jurisdictions for deeper emission cuts in the future”, and therefore “limiting the future costs associated with stranded assets” (Erickson *et al.*, 2015).

IPC (2018) has developed a comparative perspective of the low-carbon transition with Germany and Poland. This report is cited in order to evaluate how carbon lock-in affects RE deployment. A carbon-based economic system has substantial positive industrial and economical repercussion upon society, which is beneficial for the working class. Even though ruinous environmental fallout is widely known by decision makers, the fear of harmful economic outcomes due to technological phase-out strengthens the effect of carbon lock-in. Hence, rooted opinions, political calculations, habits, and cultural values demonstrate an influential role within the formation of energy policy, affecting the deployment of new energy solutions by reducing free competition (IPC, 2018).

Furthermore, IPC (2018) also demonstrates that the most debated reason for slow RE deployment in a traditional energy system is caused by existing capital-intensive assets. Due to the significant amount of upfront capital expenditure, the physical infrastructure related to electricity production, transmission and distribution are constructed with the main purpose of operating over a long period. Investments in conventional power generating assets are characterized by the assets long lifetime and capital-intensive cost structure (see figure 3.3). The main goal of investors is to operate an asset for as long as economically possible - because the returns from the asset will pay off the capital expenditure. The profits generated from operation typically exceed the operational expenditures. This results in a situation in which investors, owners, and other stakeholders will stretch the lifetime of a conventional asset, consequently, pursuing a carbon-based economy, and slowing down the deployment of renewable energy.

However, a more frequent replacement of energy systems and associated infrastructure may also play out differently. A political push for wind and solar versus coal could result in replacing assets before the end of their physical lifetime, resulting in stranded assets or sunk investments. A stranded asset can take place in the *profit period* (figure 2.4). Hence, this may occur while generating profit, or even before the unit has refunded the capital expenditure, resulting in *stranded investment* and/or *stranded profits* (IPC, 2018).

2.2.2 Estimates of Levelized Cost of Electricity

LCOE is the best approach to estimate and compare the cost characteristics of wind-, solar- and coal power generating assets. All LCOE calculations, independent of literature and source, are to some extent computed by the same methodology as illustrated in chapter 3.1.1 (equation 3.1). The central idea is to calculate annualized average costs of constructing and operating the plant and comparing this with the average yearly energy yield. However, it is worth mentioning that different LCOE computations by different actors and sources may operate with different assumptions, this will be explained for each source.

2.2.2.1 VGB Powertech (2015)

In 2015, the international technical association for generation and storage of power and heat, VGB Powertech (2015) released their LCOE estimate “LCOE 2015”. This estimate compared power plants with different power generation and cost structures. The calculations include two case situations of LCOE for coal-fired generation, a Real Case, and an Ideal Case.

In order to simplify both calculations, base-load generation is assumed in stable market conditions only focusing on the European market. However, as the European base-load market only partially consists of coal, such as anthracite, and lignite the Ideal and the Real Case have been developed in order to include both the current and base-load markets respectively.

The *real case* displayed in figure 2.5 reflects the existing scouted operation hours in the electricity market. This represents the actual number of operation hours coal contributes to the current base-load market.

The *ideal case*, illustrated in figure 2.6 indicates the general optimum range for coal-fired generation, this avoids discriminating the coal generation by including more operating hours. i.e. a higher value of energy yield. These calculations include a maximum range of full-load hours for coal. Also, the Ideal Case treats all generation types equally, thus developing a more reasonable comparison.

The report focuses merely and compares the technical system cost. Even though all technologies are affected by system costs, RE technologies (solar and wind) usually obtain higher cost associated with backing up the intermittent generation and strengthening power grids. However, a subsequent aspect that is beneficial for the RE technologies, is ignoring the *imbalance cost*. This refers to the increased cost (incremental cost) of maintaining system balance, caused by intermittent (non-dispatchable) renewable energy generation (PowerTech, 2015).

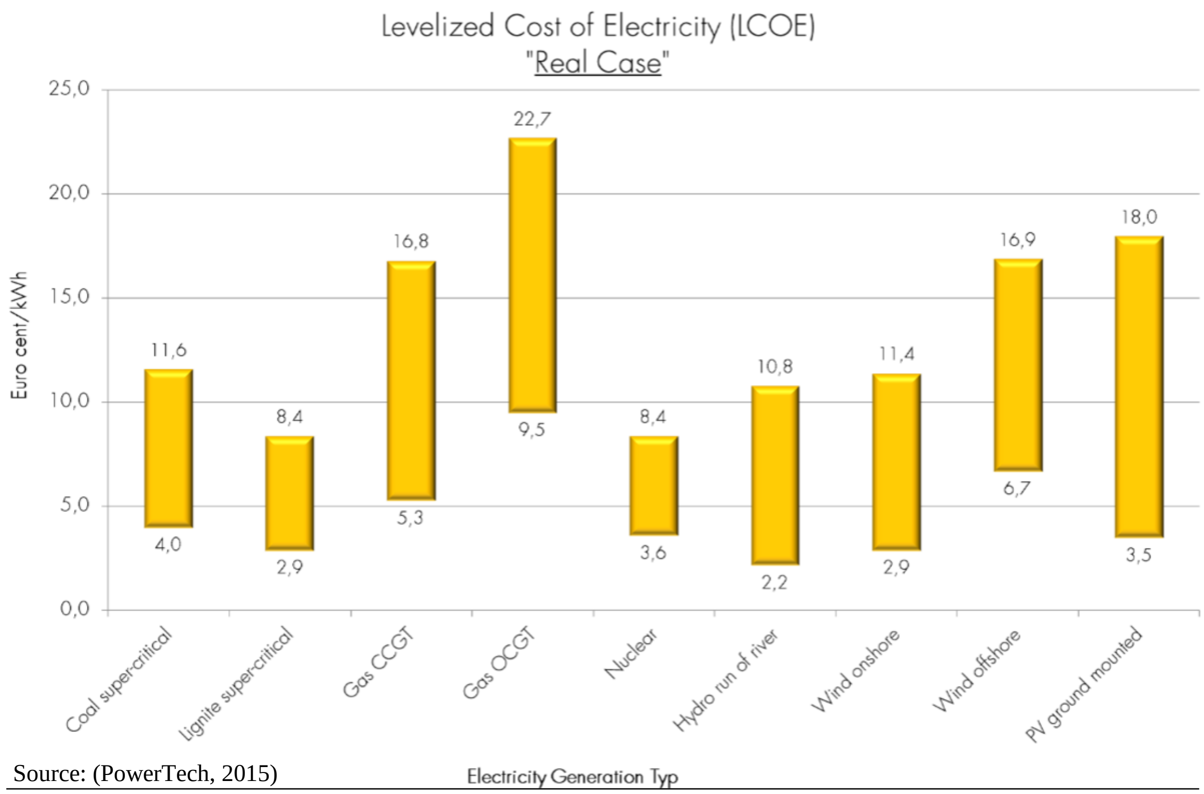
The most significant cost components of VGB Powertech LCOE calculations are represented in table 2.2 (PowerTech, 2015).

Table 2.2: Most significant cost components

Cost Components (Variables)	
Discount rate	A minimum of 4% and a maximum of 7% is set for all technologies.
Plant lifetime	Coal power plants (anthracite and lignite) have a lifetime of 40 years. While wind and solar (photovoltaic) plants are set to have a lifetime of 25 years.
Fuel cost	Due to price developments, different fuel qualities, and various sources VGB has set a spread of approximately ± 20%. The price of anthracite = € 9/MWh (average price 2014). And, the price of Lignite = € 5/MWh (delivered at the place, finished processed).
Carbon price	Is set to be € 7.5/ton CO_2 (average auction price on the EXX Leipzig for EU Emission Allowance (EUA) in the period 2005 - 2015).
Carbon factor	Anthracite = 339 kg CO_2 /MWh. Lignite = 404 kg CO_2 /MWh.

Source: (PowerTech, 2015)

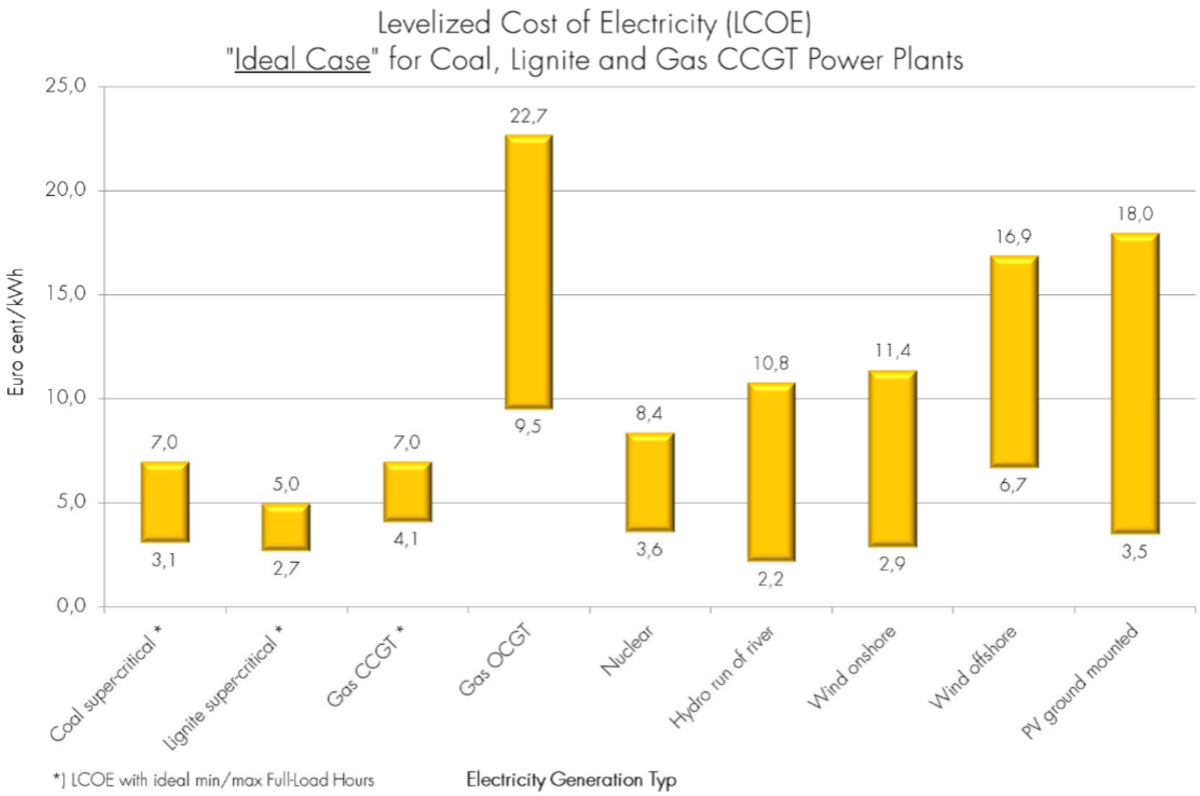
Figure 2.5: Levelized Cost of Electricity. 'Real Case'. In euro cent/kWh



Source: (PowerTech, 2015)

Figure 2.5, illustrates the LCOE of different power generating technologies, focusing on coal (coal supercritical and lignite supercritical), wind (wind onshore and wind offshore) and solar (PV ground mounted). The notation supercritical signifies a state-of-the-art coal plant design. Supercritical plants form the standard for new coal plants, demonstrating the efficiency of around 44%, compared to older technology yielding approximately 33%. Note that the 'Real Case' discriminates power generation from coal.

Figure 2.6: Levelized Cost of Electricity. 'Ideal Case'. In euro cent/kWh



Source: (PowerTech, 2015)

From figure 2.5 and 2.6, it is clearly noticeable that in both cases (real and ideal), both coal technologies (anthracite and lignite) are demonstrating a significantly lower range of minimum and maximum LCOE. For example, lignite yields a minimum of 2.7, and a maximum of 5 cents/kWh in the ideal case. This can be compared to wind onshore having 2.9 and 11.4 cents/kWh within the same range. This trend is also visible for wind offshore and PV, which is principally caused by the estimation of full load hours for each technology in the ideal case, where the maximum full-load hours are estimated to be: Lignite - 8000 h, onshore wind - 3200 h, offshore wind - 4200 h, and PV - 2000 h.

However, based upon the evaluation of the ‘Real Case’ from figure 2.5, it is noticeable that onshore wind, that has a minimum and maximum LCOE range of 2.9 - 11.4 cents/kWh, is competitive with lignite’s minimum value (2.9 cents/kWh) and the cost range of anthracite, 4 - 11.6 cents/kWh. Again, this is primarily caused by the full load hours in the base-load electricity market, within which maximum full-load hours are estimated to be: anthracite - 4500 h, lignite - 7000 h, while the RE technologies remain the same: onshore wind - 3200 h, offshore wind - 4200 h, and PV - 2000 h.

These findings demonstrate how significant the operating hours (Full-Load Hours), i.e. the energy yield, are for the LCOE calculations.

2.2.2.2 International Renewable Energy Agency (2018)

Technologies associated with power generation using coal as fuel are known to be mature. Thus, the cost of electricity generation will, to some extent, fail to demonstrate any significant cost-reduction developments in the years to come. However, renewable energy technologies are predicted to improve substantially within the next couple of years. In order to provide further insight into the cost of RE generation, IRENA (2018), International Renewable Energy Agency has developed the “Renewable Power Generation Costs in 2017”.

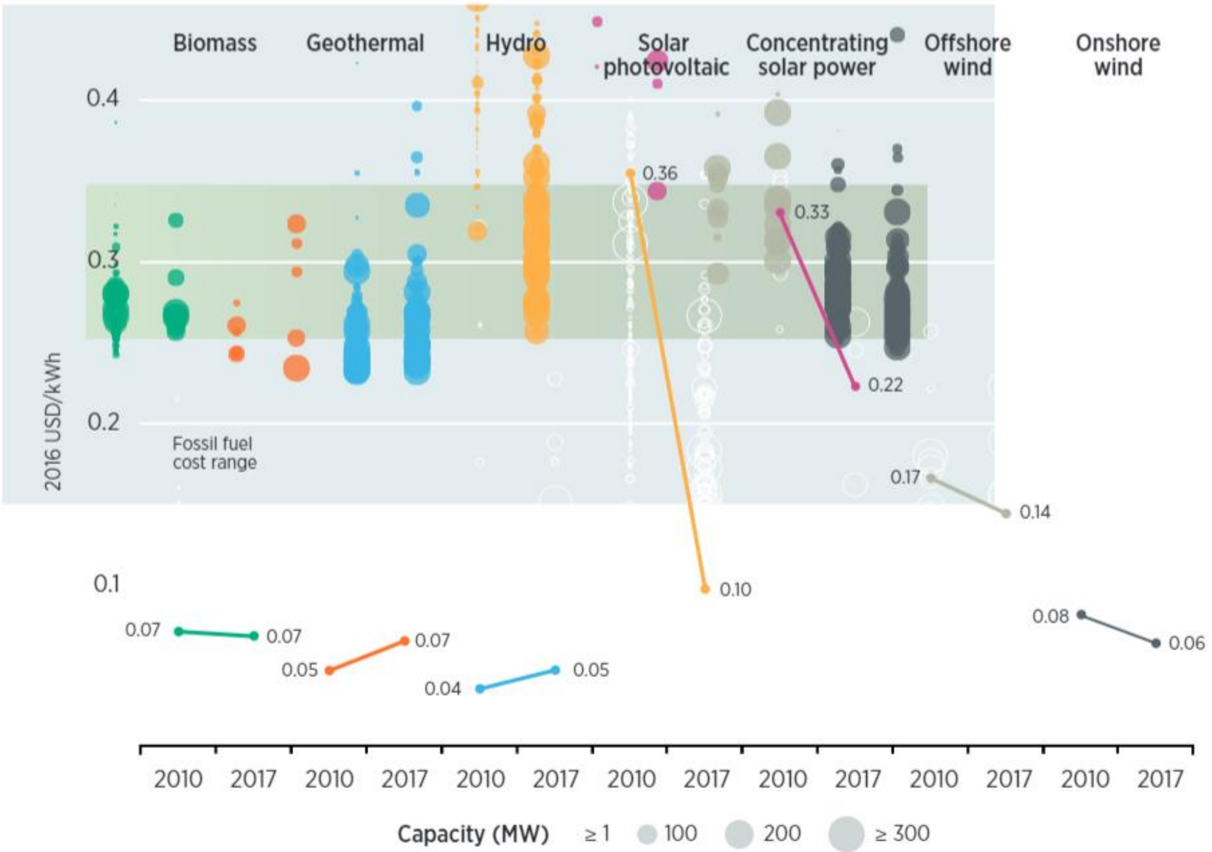
IRENA has established three main cost reduction drivers for RE:

1. Technology improvements;
2. Competitive procurement;
3. A large base of experienced, internationally active project developers.

These drivers have had a significant effect upon the cost of electricity generation from RE technology in 2017, thus, emphasizing the role of RE as an increasingly competitive method to meet new generation needs. The most significant cost reduction is demonstrated by utility-scale solar PV projects, within which the LCOE was 0.10 USD/kWh (€8.4 cent) in 2017 and has decreased by 73% since 2010. Additionally, there is also the existence of examples of PV projects in South America (Mexico, Peru, and Chile) and in the Middle East (Dubai, Abu Dhabi and Saudi Arabia) which have been obtaining record low auction prices, validating that the LCOE can be as low as 0.03 USD/kWh from 2018 onward (IRENA, 2018).

IRENA (2018) validates a similar trend to VGB Powertech (2015), demonstrating that presently, onshore wind is the most competitive technology of new energy capacity. The LCOE estimates have shown to be as low as 0.03 USD/kWh from current auctions in Germany, Brazil, and other well-suited locations. Furthermore, the IRENA 2020 outlook is estimating the lowest cost yet for solar and wind. It provides global average electricity costs of 0.05 USD/kWh for onshore wind and 0.06 USD/kWh for solar PV, thus competing on a similar cost range as power generation from fossil fuels.

Figure 2.7: Global levelized cost of electricity from utility-scale renewable power generation technologies, 2010 – 2017



Source: (IRENA, 2018)

Figure 2.7 illustrates the development of LCOE of different renewable power generating technologies, from 2010 to 2017. The size of the circles represents the capacity, in megawatt (MW), of the project associated with each technology, where the centre denotes the cost on the Y-axis. The coloured lines for the different technologies illustrate the global weighted average LCOE and its development throughout the time-period. IRENA (2018) has set the average cost of capital (discount rate) to 7.5% for OECD countries and China, and 10% for the remaining countries. The light-grey band covering a range from 0.15 to 0.45 USD/kWh illustrates the *fossil fuel cost range*.

The LCOE development of offshore wind has also demonstrated a significant cost-reduction, beginning at levels comparable to standard electricity generation from fossil fuels (0.17 USD/kWh), to 0.14 USD/kWh, the cost in 2017. The cost reduction of offshore wind illustrates a similar declining characteristic as conventional wind and solar PV, and it is expected to fall to as low as of 0.10 USD/kWh in 2020. This is mainly a result of more specialised experience and technologies suitable for the offshore environments, which increases the full-load hours, consequently, reducing the LCOE (IRENA, 2018).

2.2.2.3 Danish Energy Agency (2015)

Finally, DEA (2015), the Danish Energy Agency developed the Danish Levelized Cost of Energy Calculator. Similarly, to VGB (2015) and IRENA (2018), DEA (2015) compares the LCOE of different power generation technologies. Furthermore, the LCOE calculator also includes a social externality cost, in addition to the technological cost. Hence, it not only concerns project specific costs (CAPEX, O&M, fuel, etc.) but also the costs of systems and the added cost to society. Thus, the cost elements comprising the LCOE involve investment cost (CAPEX), fuel cost (variable OPEX), O&M costs (fixed OPEX), environmental externalities and system costs. The prices of fuel and CO_2 are obtained from “World Energy Outlook 2015”, developed by International Energy Agency (IEA). Environmental externalities costs are based upon European estimates, and system integration costs are collected from industry experience from both Germany and Denmark (DEA, 2015).

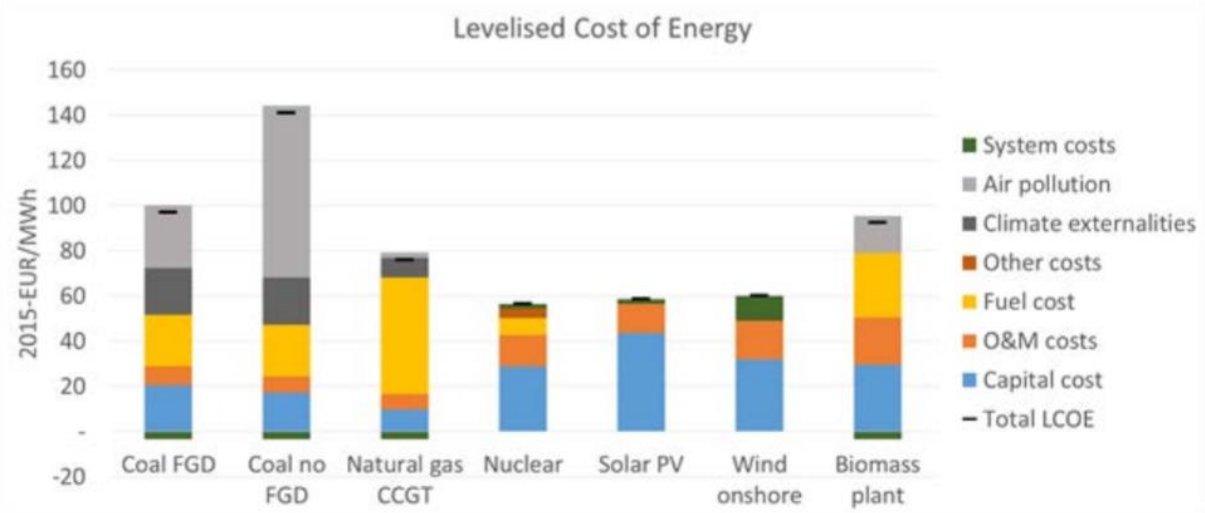
Similar to VGB (2015) and IRENA (2018), DEA (2015) operates with standard assumptions in order to compute the results illustrated in figure 2.8. The most significant assumptions are presented in table 2.3:

Table 2.3: Most significant standard assumptions

Standard Assumptions (Variables)	
Discount rate	A discount rate of 4% is set for all technologies.
Plant lifetime	Coal power plants have a lifetime of 40 years. While wind and solar (photovoltaic) plants are set to have a lifetime of 25 years.
Load hours	Includes base-load technologies, where yearly fuel-load hours for coal, wind onshore and solar PV are 5000, 3000 and 1700 respectively.
FDG	is short for ‘flue gas desulphurisation, a methodology to reduce emissions by removing acidic gases, mainly sulphur dioxide (SO_2) and hydrogen chloride (HCl).
Technological and Economic data	The technological and economic data, such as carbon price, carbon factor and fuel cost are primarily attained from ‘Projected cost of generating electricity 2015’ (IEA, 2015a).

Source: (DEA, 2015)

Figure 2.8: LCOE results for DEA's seven key technologies in 2015. In euro/MWh



Source: (DEA, 2015)

Evaluating the relevant power generation technologies, figure 2.8, shows that solar PV (€60 per MWh), and onshore wind (€62 per MWh) demonstrate lower LCOE compared to coal (100-€143 per MWh), including environmental (air pollution and climate externalities) and system costs. It is important to emphasise that system cost is highly dependent upon the added RE capacity, and the electricity systems flexibility. Hence, new RE instalments in Denmark or Germany will demonstrate a lower LCOE than other countries, given their modern high share RE and flexible electricity grids. Comparing coal power with (€100 per MWh) and without (€143 per MWh) FGD illustrates how sensitive the LCOE is to increased air pollution, which is significantly higher than the investment cost (CAPEX) of installing an FGD system.

Even though it is not included in the LCOE calculations, DEA (2015) underlines the importance of technological development. RE technology (solar and wind) is estimated to be at an early stage of the technological cost development in comparison with the conventional fossil-fuelled generation. Technological improvements, together with economies of scale are predicted to further reduce costs for years to come (DEA, 2015).

2.2.2.4 Summary LCOE

The following table (table 2.4) summarizes the most important LCOE values from the different sources: VGB (2015); IRENA (2018); DEA (2015):

Table 2.4: Summary and comparison of LCOE values. *) LCOE with ideal min/max Full-Load Hours

LCOE Summary			
Source (Year)	**Technology**	**Type**	**Value [Euro cent/kWh] (USD/kWh)**
VGB Powertech (2015)	Solar	PV (average from range)	**10.75** **(0.12)**
	Wind	Onshore wind: (average from range)	**7.15** **(0.08)**
		Offshore wind: (average from range)	**11.8** **(0.13)**
	Coal	Super-critical: (average from range)	**10.3** (real case) **(0.12)** **5.05** (ideal case*) **(0.06)**
		Lignite super-critical: (average from range)	**5.65** (real case) **(0.065)** **3.85** (ideal case*) **(0.045)**
IRENA (2017)	Solar	PV	**8.4** **(0.095)**
	Wind	Onshore wind:	**5.0** **(0.06)**
		Offshore wind:	**11.8** **(0.13)**
	Coal	All (average. Lower fossil fuel cost range)	**10.0** **(0.11)**
DEA (2015)	Solar	PV (including: CAPEX, OPEX and System cost)	**6.0** **(0.07)**
	Wind	Onshore wind: (including standard costs and system cost)	**6.0** **(0.07)**
		Offshore Wind: (DEA estimates. Including standard costs and system cost)	**8.5** **(0.096)**
	Coal	FGD: (including standard costs, system cost, fuel cost, climate externalities, and air pollution)	**10.0** **(0.11)**

		Without FGD: (including standard costs, system cost, fuel cost, climate externalities, and air pollution)	**14.25 (0.16)**

It is noticeable in table 2.4, that the LCOE values demonstrate, to some extent, a similar cost range per technology. The reason for the dissimilarities is the different assumptions each source has taken into account for their calculations. The most significant parameters that are affecting the values are the discount rate, load hours, either including or neglecting the system costs and externalities. Therefore, table 2.4 is more suitable as a summary illustration rather than a comparison between sources. However, evaluating the LCOE values per source and technology demonstrates relevant findings.

DEA (2015) shows how significant climate externalities and air pollution costs are for fossil fuel generation, as well as providing evidence for how efficient flue gas desulphurisation (FGD), namely SO_2 and HCl removal, is in terms of cost reduction. Even though solar PV and onshore wind include systems costs, they both obtain €6 cent per kWh, thus outcompeting the thermal sources. IRENA (2018) also shows a competitive range for both solar PV and onshore wind, having €8.5 and €5.0 cent per kWh respectively. €10 cent per kWh is an average estimate for coal generation taken from the lower cost range for fossil fuel power generation in IRENA (2018) – "Renewable Power Generation Cost". Coal plants are considered to be the cheapest power generation units among fossil fuels. VGB (2015) validates what are considered to be the most realistic values, given its comprehensive assumption presented in table 2.2 (cost components). The values in table 2.4 are average values from the min/max range in the report. Both the ideal and real cases make it clear that coal plants are very cost competitive, having an LCOE as low as €5.65 (real case) and €3.85 (ideal case) cent per kWh for super-critical lignite plants. This is the most widespread technology, having the cheapest operational expenditures. Other super-critical plants are assumed to operate with anthracite as feedstock, consequently operating with more expensive fuel, thus obtaining €10.3 (real case) and €5.05 (ideal case) cent per kWh. The LCOE for lignite plants represent the most relevant values for Germany, especially due to their national decommissioning plans for anthracite mines and reducing their dependency on imports. Furthermore, onshore wind provides a very competitive LCOE of €7.15 cent per kWh, while solar PV retains a value of €10.75 cent per kWh. These values are based upon the European Electricity Market, marking a suitable benchmark for the German Electricity Market.

2.2.3 Estimates of Stranded Coal Assets

Coal-fired power production is vulnerable in all electricity markets having ambitious initiatives to reduce carbon emissions. i.e. coal assets (power plants) has a risk of being stranded. Stranded assets refer to assets that have suffered from premature write-downs. Various factors could result in assets becoming stranded, such as changes in government regulations, limiting the usage of fossil fuels for power generation. E.g. introducing carbon pricing; new legal actions; or most relevant, a change in demand. E.g. a shift towards RE due to lower costs.

In order to evaluate an approximation of stranded coal assets in Germany, it is necessary to study a report from the Institute for Energy Economics and Financial Analysis. IEEFA (2016) include an estimate for three new coal power plants in the Netherlands, which were put into service in 2015. The report assesses the impact of national pressures on the value of Eemshaven (1600 MW, RWE), Maasvlakte (1070 MW, Uniper) and Rotterdam (800 MW, Engie).

Similarly, to Germany, the coal industry in the Netherlands faces an uncertain future. Political pressure creates difficulties and uncertainties for coal-fired power while promoting competing RE implementation. In the report, IEEFA (2016), stated that RWE, Uniper, and Engie have taken unannounced losses on the new plants only after one year of operation, collectively worth billions of euros, consequently indicating a weak investment situation for new coal assets in Europe. Eemshaven, Maasvlakte and, Rotterdam had an approximate original total CAPEX of €3 billion, €1.95 billion and €1.55 billion respectively. After one year of operation, the utility balance sheets have dropped to approximately €1 billion for each plant.

IEEFA (2016) concludes that the coal power plants provide insufficient economic results in terms of meeting their original valuation and investment return targets, consequently putting further financial deterioration on RWE, Uniper, and Engie. These three power plants are recognised as good examples for any new-build coal power plants in western Europe, thus underlining future complications for existing coal-fired power generation in the German electricity market.

The uneconomical trend is recognised from a wide range of possible policy or market scenarios. The reason for investing in the assets in 2015, was assumed to be out-of-date, only one year later, given the lack of existing government subsidies such as capacity-market support. In line with a common European agreement for backup options in electricity markets, gas-fired power plants are identified as having increased flexibility, whilst also emitting less carbon. At the same time, renewable energy is a more cost competitive alternative. Additionally, an increased political focus on other functional alternatives exists, this includes increased interconnector capacity (cross-border capacity), more demand response and electricity storage.

The report states that early retirement may be the most cost-competitive alternative, given an uncertain political atmosphere with more sustainable climate policies. This would result in the assets being stranded and decommissioned while still generating positive cash flows. Thus, raising an additional high-cost aspect, namely the question regarding compensation for utility-owners.

A coal-fired power plant is estimated to operate for up to 45 years. A utility-owner would maximise the revenue for an investment given that the asset generates profit. Given today's unpredictable and highly dynamic policy regimes, it is difficult and risky to estimate future investments in coal-fired generation. Between planning and the production of the first megawatt-hour, it takes roughly 5 to 7 years to build a large coal-fired power plant such as Eemshaven, Maasvlakte and Rotterdam (Schlissel, Smith and Wilson, 2008). This indicates that the investment decision by RWE, Uniper, and Engie was taken around 2008/10, demonstrating a period with a different focus on energy policy. The years after the financial crisis in 2007/08 were more focused on securing stable jobs than promoting expensive and low carbon solutions.

The three brand-new power plants are at risk of already becoming stranded assets due to the following main aspects. Firstly, the investment decision for the three assets was based upon expectations of significant growth in power demand, which did not come through as expected. Additionally, the increased capacity of solar and wind in neighbouring Germany was highly underestimated, resulting in a significant cross-border capacity of surplus near-zero marginal cost sources, dictating electricity prices and negatively affecting the full load hours of thermal plants. Lastly, the focus on international agreements for carbon-emission reductions, as well as an increased focus on national coal-exit policy weakening the business case for a coal-fired power plant in the Dutch electricity market.

These examples and aspects can be easily leveraged in terms of evaluating future prospects for coal-fired power plants in the German electricity market. Independent of country or market (especially western Europe) stranded asset risk arises due to highly competitive RE, new market trends and stricter climate change policies, and more focus/investments in energy efficiency (IEEFA, 2016).

3 Methods & Data

The existing literature regarding LCOE establishes a common metric for the direct comparison of different power producing technologies. This is useful when comparing the cost of utility-scale renewable energies, such as solar PV and wind. Zweifel et al. (2017) define LCOE as the average production cost which primarily depends on the operational cost (fuel etc.) as well as on the annualized investment expenditure in combination with the rate of capacity utilization. Solar PV and wind are poignant examples of immature technologies which are continuing to develop, as they are young technologies. Within the context on Energiewende, this creates a problem as policymakers and business leader alike need a way to compare dissimilar energy producing assets, both in terms of differing renewable technologies and when comparing renewables to coal. Thus, LCOE emerged as a method for quantifying and comparing the cost-based competitiveness of different power producing technologies. LCOE calculations overcome the problem of comparing the cost of different power producing technologies, allowing for the comparison of different technologies (e.g. solar, wind and coal) of dissimilar lifespans, project size, capital investment and operational cost, risk, return, and capacities.

3.1 Methods

3.1.1 Levelized Cost of Electricity

The methodology will include computation and analysis of LCOE estimates from Rystad Energy's databases, Renewables, and PowerCube. In order to perform these analyses, a key part of this project also includes expanding the database through the insertion of new variables for new kind of calculations and analysis, which is explained in detail in section 3.2.2.

An asset, in this case, is referred to as a single power producing resource, either a steam turbine (for coal), wind turbine or a solar PV panel. The PowerCube includes a list of costs for each asset, per year. The LCOE computation is developed by calculating the yearly cost, and the yearly power production output per asset:

LCOE (or average production cost) primarily depends on the cost of fuel as well as on the annualized investment expenditure in combination with the rate of capacity utilization. Eq. (3.1) demonstrates the electricity price P_E, is the *break-even* price needed to offset investment expenditure Inv_0 and unit variable cost c_{var} (Zweifel et al, 2017). This is the interpretation of levelized cost of electricity, also known as unit production cost from Zweifel et al. (2017). LCOE is usually taken as a proxy for the average power price that the asset must receive in a market to break even over its lifetime. In the context of electricity production, the break-even price is the price of the electricity a power generation asset must obtain in order to cover the cost of acquiring, owning and operating the asset. As LCOE is forward-looking and take the assets lifetime into consideration, a discount rate of 7% is applied in Rystad's models. A standard discount method, discounts future values too much, therefore, a mid-year discounting is used to assume that all costs and production output occur halfway through the year to average it out. LCOE is calculated for each individual asset. If a bundle of similar technology assets is analysed together, the resulting value will be the weighted average of the different LCOEs per asset.

Eq. (3.1) can be simplified and expressed as Eq. (3.2), where the present value (PV) for the cost and the energy output from the base year is calculated. In general, aggregate terms, the LCOE equation used in Rystad Energy's databases is illustrated in Eq. (3.2) (Rystad Energy, 2018). The formula is the same regardless of the underlying technology, whilst the values of the variables differ by technology. Separate LCOE formulas for renewable technology (solar and wind) and for coal technology are presented in Eq. (3.3) and Eq. (3.4) respectively. A further break down of the aggregates (variables) is denoted in the data section (chapter 3.2.1).

In order to do modelling and analysis of LCOE calculations, which is explained in this section, database construction has been necessary and a significant part of this project. This has included developing and inserting new equations, allowing new variables to work together with the existing data in the PowerCube. This is explained further in section 3.2.3, database construction.

$$P_E = \frac{Inv_0}{Q \times PVF_{i,T}} + c_{var} \quad (3.1)$$

P_E = Price of energy

Inv_0 = Investment expenditure (incl. financing cost, CAPEX)

c_{var} = Total variable cost (incl. fuel cost, OPEX)

Q = Total output (quantity)

$PVF_{i,T}$ = Present value factor in the year t

$$LCOE = \frac{Present\ Value\ of\ Cost}{Present\ Value\ of\ Energy\ output} \quad (3.2)$$

$$LCOE = \frac{\sum_{t=0}^{T} \frac{cost_t}{(1+r)^t}}{\sum_{t=0}^{T} \frac{production_t}{(1+r)^t}}$$

$$LCOE = \frac{\sum_{t=0}^{T} \frac{[I_t + M_t + F_t]}{(1+0.07)^{(t+0.5)}}}{\sum_{t=0}^{T} \frac{[E_t]}{(1+0.07)^{(t+0.5)}}}$$

I_t= CAPEX in the year t

M_t= O&M costs in the year t

F_t = Fuel price expenditure in the year t

E_t = Net electricity production in the year t

r = Discount rate

T = Life of the system

t = year (t + 0.5 is mid-year discounting)

$$LCOE_{renewable} = \frac{\sum_{t=0}^{T} \frac{[I_t + M_{t-fix} + M_{t-var}]}{(1+0.07)^{(t+0.5)}}}{\sum_{t=0}^{T} \frac{[E_t]}{(1+0.07)^{(t+0.5)}}} \quad (3.3)$$

$$FLCOE_{coal} = \frac{\sum_{t=0}^{T} \frac{[M_{t-fix} + M_{t-var}]}{(1+0.07)^{(t+0.5)}}}{\sum_{t=0}^{T} \frac{[E_t]}{(1+0.07)^{(t+0.5)}}} \quad (3.4)$$

M_{t-fix}= fixed O&M costs in the year t

M_{t-var}= variable O&M costs in the year t

Note:

Fuel cost (F_t) (eq. 3.1) is a substantial cost parameter within the variable OPEX (M_{t-var}) for coal

Eq. (3.3) and Eq. (3.4) illustrate separate LCOE formulas for renewable-plants and coal-plants respectively. The equations show which items are included or excluded for different technologies. Eq. (3.3) represents the LCOE for solar and wind. Solar and wind do not rely on fuel to generate electricity, therefore the LCOE formula excluding the fuel price expenditure item (F_t) within the variable O&M costs. Eq. (3.4) represents the LCOE for coal, and is named *forward-looking levelized cost* (FLCOE). The CAPEX item (I_t) in the FLCOE formula is excluded for coal. i.e. it is denoted as a sunk investment cost. More specific information and detailed tables, explaining the variables are presented in the data section (chapter 3.2.1).

3.1.1.1 Sunk Cost

In this report, the coal CAPEX can be regarded as a sunk cost. The break-even price is forward-looking, meaning that if at a certain production point, a coal asset has a finalized facility CAPEX, this asset is only evaluating future (forward-looking) operational performance based on future cost (FLCOE) of operating the asset. This is caused by the facility CAPEX being denoted as a sunk cost, hence, a cost which has already been incurred and cannot be recovered. The apparent trade-off between CAPEX and OPEX, usually makes the comparison of the overall costs of different power generating technologies a challenging issue. LCOE calculations simplify this issue.

The decision of either investing in a new solar or wind project, compared to continuing the operation of an existing coal power plant is a topic that will be examined further in this report. An investment decision within new power generating assets needs to be considered based upon the background of the competitive assets operating in the same market. Compared to a wind or solar plant, an operational coal power plant has a substantially fixed and variable OPEX (see cost structures, section 3.2.3.2). Therefore, wind and solar assets are more cost competitive based on daily operation. However, substituting the coal asset would require the decision maker to also evaluate the substantial upfront CAPEX of a new RE project. Continuing the operation of the coal plant would in the short term require a lower break-even price than that of new wind or solar asset when accounting for CAPEX. E.g. the decision of either continue operating a coal plant or invest in a new solar plant taken at one point in time, should preferably be based on the levelized cost/break-even price of both technologies. LCOE calculations include both decommissioning cost for the coal plant, and the facility CAPEX for the solar plant. i.e. the replacement cost can be estimated from the levelized cost.

3.1.2 Sensitivity Analysis

In order to examine what values particular variables have to assume in order for new renewables to be cheaper than existing coal plants, this project will conduct a sensitivity analysis of the LCOE computations.

Typical *economic variables* which can be changed to adjust the levelized cost output include the carbon tax, emission permit price, interest rates, subsidies, and commodities prices. These are variables which directly affect costs such as CAPEX, fuel cost (OPEX) and discount rate, and thus the competitive nature of a power generating asset.

A sensitivity analysis could also include changing *technological variables* within the LCOE equation, such as variable OPEX (efficiency), downtime, capacity factor, and abandonment costs. These variables are linked to the operational aspect and can be used to vary and examine the energy yield (net electricity output), and how this affects the overall costs throughout the lifetime of the asset.

Having considered the aforementioned variables, the sensitivity analysis performed in this project is examining and adjusting the two main economic variables:

1. The *capital expenditure (CAPEX)* for renewable plants (solar PV, onshore and offshore wind).
2. The *price of carbon* (CO_2 price), which is directly related to the OPEX and net electricity cost of thermal sources (coal).

CAPEX for new solar and wind installations are acknowledged to be a major part of the cost, and thus dictate the competitiveness of the technologies. This is explained in detail in section 3.2.3.2 and in figures 3.2, and 3.3. Given the scope of this project, which is restricted to evaluating existing coal plants with sunk investment cost, the CAPEX for coal plants is not relevant. However, the CO_2 price is recognised to play an important role for the total operational costs for a coal power plant, this is exemplified further in chapter 2.2 (Literature Review), under section 2.2.2 (Estimates of Levelized Cost of Electricity) and figure 2.8.

Table 3.1 illustrates the scenarios for both renewable CAPEX-development (Renewable Energy Scenario) and CO_2-price for coal plants (Thermal Energy Scenario). The CAPEX-development for renewables is separated into two parts: the base case and the CAPEX-development scenarios of 10%, 15%, and 20% CAPEX reduction, namely *renewable current policies scenario* (RCPS), *renewable new policies scenario* (RNPS), and *renewable sustainable development scenario* (RSDS).

The base case is based on existing estimated developments analysed using CAPEX Year Factors (appendix: table A9), which is estimated developments in costs for onshore wind, offshore wind, and solar PV. This will be further explained in detail in section 3.2.1 (variable definitions).

The CAPEX-development scenarios are based on more aggressive scenarios from the already implemented CAPEX Year Factors. Even though the scenario-naming are the same as for the scenarios in the World Energy Outlook by International Energy Agency (IEA), the 10, 15, and 20% reduction are based on Rystad Energy research and analysis low, medium, and a high case for CAPEX reduction. The IEA names for CAPEX reduction are used in the analysis for simplicity, thus linking them up to the CO_2-price scenarios, which are directly based on IEA's outlook, this is further explained below.

The CO_2-price scenarios are also presented in two parts. The base case demonstrates the current CO_2-price situation. Germany adopts the EU CO_2-price from the European Emission Allowances (EUA), which is priced as a commodity under the EU Emissions Trading System (EU ETS). At the time of writing the EUA CO_2-price is currently around $28 per tonne CO_2. $16 per tonne is the nominal price on April 1, 2018, which is used in Goyal et al. (2018), "The State and Trends of Carbon Pricing 2018" by the World Bank Group (Goyal *et al.*, 2018). This value also demonstrates to be a suitable level, as it is an approximated average value of the EUA in 2018, therefore it is applied as the CO_2-price in the Base Case Scenario for all years before 2018. The second part includes the three IEA CO_2-price scenarios for the European Union from the World Energy Outlook 2016. *Current policies scenario* (CPS) consist of a CO_2-price of $18, $30 and $40 per tonne CO_2 for the year 2020, 2030 and 2040 respectively, whilst, *new policies scenario* (NPS), has a CO_2-price of $20, $37 and $50 per tonne CO_2, and *sustainable development scenario* (SDS), includes a CO_2-price of $20, $100 and $140 per tonne CO_2 for the same time period. CPS includes only the effect of the current policies, whilst NPS also concern the likely effects from communicated policies. i.e. including the implementation of announced, new policy targets, in relation to the consideration of the impact of these policies and measures that are firmly in place within the legislation as of mid-2017. The SDS includes the policies which are necessary to put the world on track to meet goals related to climate change and universal access to clean air (IEA, 2015b). Even though the EUA CO_2-price is currently above IEA's 2020 estimate of $20 per tonne CO_2, Rystad Energy research and analysis has acknowledged the scenario to be a likely outcome. The development of the CO_2-price is further explained in the data section (CO_2-price, section 3.2.3.6).

Table 3.1: Sensitivity Analysis Scenarios. * the base case concerns the bau scenario implemented in the PowerCube

Sensitivity Analysis				
Thermal Energy Scenario	Renewable Energy Scenario	Year	CO2-Price (USD/tonne CO_2)	Capex Reduction (%)
Base case*	Base case*	All years	16	-
CPS	RCPS	2020	18	10
		2030	30	
		2040	40	
NPS	RNPS	2020	20	15
		2030	37	
		2040	50	
SDS	RSDS	2020	20	20
		2030	100	
		2040	140	

The CAPEX-development scenarios will be directly applied in Eq. (3.3) ($LCOE_{renewable}$) by varying the CAPEX variable (I_t). The implementation of the CO_2-price is included in Eq. (3.4) ($FLCOE_{coal}$), by directly adjusting the O&M costs variable (M_t). The reason for implementing the CO_2-price ($/tonne) within the M_t variable is that an emission tax has the same characteristics as variable operational costs, hence scaling with net electricity output, dictating tonnes of CO_2 emissions.

3.1.2.1 Cost competitive condition

The condition in which new renewable plants are equally or more cost competitive than existing coal plants could be derived from Eq. (3.5). On the theoretical level and the assumption made in this report, fulfilling this condition will demonstrate an important point of inflection within which utility-owners/investors will scrap the existing coal plant. However, in reality, the exact future costs are not known, consequently making the decision whether or not to scrap an existing coal plant less clear.

$$LCOE_{renewable} \leq FLCOE_{coal} \qquad (3.5)$$

$$\frac{\sum_{t=0}^{T} \frac{[I_t + M_t]}{(1+0.07)^{(t+0.5)}}}{\sum_{t=0}^{T} \frac{[E_t]}{(1+0.07)^{(t+0.5)}}} \leq \frac{\sum_{t=0}^{T} \frac{[M_t + F_t]}{(1+0.07)^{(t+0.5)}}}{\sum_{t=0}^{T} \frac{[E_t]}{(1+0.07)^{(t+0.5)}}}$$

3.2 Data

It exists different cost components, Rystad Energy research and analysis has developed assumptions for each cost component. These assumptions differ not only by technology but within each technology by type. So, for each cost component, Rystad Energy develops technology-type specific assumptions based on scouted values and market research. This section concerns an introduction to the data, the explanation of the variables and the demonstration of the assumptions which are needed in order to produce the plant-level data.

All tables, illustrations, and calculations in the data-section of chapter 3 and the analytical results chapter 4 of this report are unless otherwise stated, based on the output of the software database Renewables and PowerCube (Cube Browser) of Rystad Energy, containing in-depth information on the global upstream power market. Rystad Energy is an energy business intelligence firm, that offers consultancy and data services. The Renewables and PowerCube databases contain plant-level data collected by internal Master Data Services (MDS), as well as washed, harmonized and calibrated data from renowned sources, such as IRENA, IEA, EIA, and UNECE.

The increasingly strong public and political motivation, as well as international climate change mitigation plans, such as the Paris Agreement, have developed a robust global framework for promoting market data transparency of deployed low-carbon solutions and underlying support mechanisms. This is developed with the aim of assessing collective progress and realizing the purpose of national and international mitigation plans, as well as sharing information to all participants. The available market information is also meant to strengthen individual actions by letting more technological participants consult less technologically developed participants (UNFCCC, 2018b).

The high level of market transparency has also improved the general assessment of RE technologies, including their performance, deployment, installed capacity and economics. This results in an abundant amount of available data and information, which emphasises the realistic picture that can be drawn from the Renewables and PowerCube databases.

3.2.1 Variable Definitions

A further break down of the aggregates (variables) building up the LCOE formulas are denoted in table 3.2. The table illustrates which items are included or excluded for different technologies. Most importantly, is the difference in CAPEX (I_t), O&M costs (M_t), and fuel cost (F_t). Table 3.2 also specifies the location of a detailed explanation for each variable.

Table 3.2: LCOE variable definitions per technology. Explanation and location, or value

Variables	Technology	Included/excluded & explanation/value	Appendix location
CAPEX (I_t)	Solar	Included: CAPEX Solar PV	Table A1
	Wind	Included: CAPEX Offshore Wind & CAPEX Onshore Wind	Table A2 TableA4
	Coal	Excluded: Sunk Cost	-
O&M costs (M_t)	Solar	Included: Fixed OPEX	Table A6
	Wind	Included: Fixed & Variable OPEX	Table A5 & A6
	Coal	Included: Fixed & variable OPEX	Table A7 & A8
Fuel cost (F_t)	Solar	Excluded: Renewable	-
	Wind	Excluded: Renewable	-
	Coal	Included: Included in Variable OPEX	Table A7
Production (E_t)	Solar	Included: Scouted Installed Capacity, Capacity Factor & Scenarios	Table 3.8
	Wind		
	Coal		
Discount rate (r)	Solar	**7%**	-
	Wind		
	Coal		
Lifetime (T)	Solar	**25**	-
	Wind	**25**	
	Coal	**45**	

In order to provide an in-depth explanation of the LCOE equations and calculations, a further break down of the variables is explained in the following sub-sections. The appendix in chapter 7, includes a cost-type specific detailed illustration on how the LCOE variables are developed and calculated. The sub-sections also include illustrations of small excerpts for the variables. Additionally, chapter 3.2.2.2, demonstrates typical cost characteristics for different technologies, illustrated through cost structures. The following sub-chapters include detailed descriptions of the assumptions per variable.

3.2.1.1 CAPEX

The most relevant capital expenditure for power production is the facility CAPEX. Facility CAPEX refers to a company's spending on a physical facility asset, in this case, the power plant. CAPEX is a major part of a power producing company's investment. In the power generating industry physical assets are essential for the production of electricity.

This report excludes the CAPEX for coal-fired power plants. This is due to the facility CAPEX being denoted as a sunk cost for existing/operating coal plants. Hence, a cost which has already been incurred and cannot be recovered. However, the CAPEX is highly relevant for new solar PV, offshore and onshore wind plants. Below, the LCOE variables and calculation methodology will be explained for each technology.

3.2.1.1.1 Solar PV

The CAPEX for solar PV concerns different CAPEX types, namely, *fabrication of inverter*, *fabrication of solar PV module*, and *transportation & installation*. The CAPEX is measured in USD per kW power produced and the types have different CAPEX levels depending on the size-range, denoted in megawatts. The larger the range, the smaller the cost (USD per kW). Each type has also been specified with a start-up year, hence at what time on the timeline the CAPEX arises, as well as a number of estimated CAPEX years, which demonstrates for how many years the cost is estimated to run. Both year factors also scale with the size-range of the CAPEX type (appendix: table A1).

Rystad Energy research and analysis estimates that each CAPEX type obtains a certain percentage of the total cost: fabrication of the inverter is set to be 10% of the total cost; fabrication of the solar PV module is set to be 45% of the total cost, and equally is the transportation and installation set to be 45% of the total cost. Table 3.3 illustrates a brief excerpt from the detailed CAPEX Solar PV table in the appendix (appendix: table A1).

Table 3.3: Brief LCOE variable definitions for CAPEX Solar PV

CAPEX Solar PV				
CAPEX type (range MW)	CAPEX USD per kW	Start-up year (no. of capex years)	Comment	Source
Fabrication Inverter (75-150)	150	1 (2)	10% of total cost of 1500 USD/kW	(Rystad, 2017)
Fabrication Solar PV module (75-150)	675	1 (2)	45% of total cost of 1500 USD/kW	(Rystad, 2017)
Transportation and installation (75-150)	675	1 (2)	45% of total cost of 5600 USD/kW	(Rystad, 2017)

3.2.1.1.2 Offshore Wind

Offshore wind is known to be a more complex technology in terms of the installation procedure, therefore obtaining more CAPEX types, such as *fabrication of turbine*, *installation of turbine*, *fabrication of array cable*, *installation of array cable*… etc. Even though the granularity is less than for solar PV, the CAPEX types are also classified in terms of a size-range, as well as specifying what the CAPEX type is determined by (capacity in kW/MW, length in km, etc.). The cost parameters are either in USD per kW for power produced or USD per km for costs associated with cables.

The variables are calculated through different methods, such as the fabrication cost of turbines above 7 MW is calculated by a cost reduction iteration, comparing turbine fabrication of 6 MW turbines and 4 MW turbines. The installation cost of turbines above 7 MW (8 MW) is calculated to have a 45% cost reduction compared to a 4 MW turbine. Additionally, fabrication and installation of the foundation are calculated to be 19% and 7% of total CAPEX respectively. Also, fabrication and installation project management costs are set to be 7.5% and 2.5% of total CAPEX. See table A2 in the appendix for more details regarding variable calculations. Table 3.4 illustrates a short extract.

Table 3.4: Brief LCOE variable definitions for CAPEX Offshore Wind

CAPEX Offshore Wind				
CAPEX type (range kW)	Determined by	Cost Parameter (unit)	Comment	Source
Fabrication Turbine (5000-7000)	Turbine Capacity kW	1630 (USD/kW)	Calc. cost reduction for turbine fabric for 6MW compared to 4MW turbine	(TCE, 2017)
Installation Turbine (5000-7000)	Turbine Capacity kW	120 (USD/kW)	30% cost reduct. for turbine install. for 6 MW compared to 4MW turbine	(TCE, 2017)
Fabrication Foundation	Plant Capacity MW	850 (USD/kW)	19% of average CAPEX of 4471 USD/kW	(IRENA, 2012)

The CAPEX for offshore wind does also specify both, converter station and substation requirements (appendix: table A3). Based on scouted market values, Rystad Energy research and analysis has calculated that the need for converter station and substation occurs when: the minimum distance to the shore is 30 km for converter station and 1 km for a substation, the minimum plant capacity is 400 MW for converter station and 45 MW for a substation, and the capacity limit for one station is 1200 MW and 500 MW respectively.

In addition to the variable definitions (appendix: table A2) and the converter/substation requirements (appendix: table A3) for CAPEX offshore wind, a *CAPEX offshore wind country factor* is applied in the PowerCube database. The country factor denotes a country-specific number between 0.8 and 1.2 which demonstrates whether or not a country is estimated to be in the lower (0.8) or higher (1.2) cost range for the development, installation, and implementation of offshore wind systems. Germany has been given a country factor of **1.07** which is in the upper medium range.

3.2.1.1.3 Onshore Wind

Onshore wind demonstrates similar characteristics as offshore wind. However, the onshore technology is much more mature, thus demonstrating a wide range of cost parameters determined by size-range in kW and different hub heights in meter. Onshore wind includes CAPEX types such as *fabrication of turbine*, *fabrication of foundation*, *installation project management cost... etc.* The CAPEX for onshore wind is acknowledged to be a cheaper technology given the less complex installation procedure. Additionally, an onshore installation requires cheaper fabrication and installation of cables, as well as less expensive system costs, such as export cables, substations, and converter stations, which is demonstrated to be a significant cost parameter.

The CAPEX for different types is determined by different assumptions. Most importantly, it is assumed that 90% of the total turbine price is the fabrication costs, and the remaining, 10% are set to be installation costs. Additionally, cost reductions occur for lower hub heights and higher turbine capacities for both fabrication and installation. See table A4 in the appendix for more details regarding onshore wind variable calculations. Table 3.5 illustrates a short extract.

Table 3.5: Brief LCOE variable definitions for CAPEX Onshore Wind

CAPEX Onshore Wind					
CAPEX type (range kW)	Determined by	Second Determined By (lower limit m)	Cost Parameter (unit)	Comment	Source
Fabrication Turbine (< 3000)	Turbine Capacity kW	Hub height m (120-140)	1410 (USD/kW)	*	(VDMA, 2017)
Installation Turbine (< 3000)	Turbine Capacity kW	Hub height m (120-140)	157 (USD/kW)	**	(VDMA, 2017)
Fabrication Foundation	Plant Capacity MW	-	288 (USD/kW)	18% of average CAPEX of 1600 USD/kW	(WEC, 2016)

* Assuming 90% of the total turbine price is the fabrication costs. Cost reductions for lower Hub Heights and higher Turbine Capacities ** Assuming 10% of the total turbine price is the installation costs. Cost reductions for lower Hub Heights and higher Turbine Capacities

As for the offshore wind CAPEX, a *CAPEX onshore wind country factor* was developed. This demonstrates a lower (0.8) and higher (1.2) range signifying the cost of the development, installation, and implementation of onshore wind systems. The onshore country factor in Germany is set to be **0.95** which is based on developed European countries with offshore industry knowledge (WEC, 2016).

3.2.1.2 OPEX

Solar, wind and, coal also demonstrate different methods in order to break down the operational and maintenance (O&M) costs. These costs are denoted as fixed and variable operational expenditures. Fixed OPEX stays the same irrespective of the level of output, whilst variable OPEX scale with the production.

Fixed OPEX is the constant general expenses which the asset needs to spend in order to remain operational. For a power producing company, the OPEX is related to O&M costs, such as salaries, taxations, and regular maintenance.

Variable OPEX is the changing general expenses which the asset needs to spend in order to remain operational. The majority of variable OPEX is a fuel cost and cost of the variable labour force.

3.2.1.2.1 Renewables

Variable OPEX for solar and wind demonstrates different characteristics. For onshore and offshore wind, a variable OPEX of 3 and 18 USD, is included per MWh respectively. Both estimates are developed on the background of the tear and wear of equipment. Offshore wind is set to obtain a variable OPEX, six times bigger compared to onshore. This difference is mainly caused by the complexity of offshore operations and maintenance procedures. Both ground-mounted and floating solar PV are assumed to obtain *no* variable OPEX in the database (appendix: table A5).

Fixed OPEX is a more weighted area of interest for renewables. Onshore wind demonstrates a fixed OPEX of 35 USD per MWh, while for offshore wind, 110 USD per MWh. Additionally, all types of solar PV plants have a fixed OPEX of 20 USD per MWh (appendix: table A6).

3.2.1.2.2 Coal

The operational expenditures of thermal power plants, such as a coal plant provide on average a higher level of both variables, and fixed costs, and more varying costs due to a large amount of different power plant types. The database contains OPEX estimates for as many as 16 different types of coal plants. In descending order, the most implemented coal technologies in the German electricity market are subcritical, supercritical and ultra-supercritical. All three types involve different subcategory technologies.

Subcritical coal plants are among the oldest coal plants in Germany and, on average, have a variable OPEX of 37 USD per MWh, which is slightly higher than supercritical and ultra-supercritical having 35 and 31 USD per MWh respectively. The notation *supercritical* signifies a state-of-the-art coal plant design. Supercritical plants are the standard for newer coal plants, having an efficiency of around 40%, as compared to older technologies such as subcritical yielding approximately 34%, this is further demonstrated in section 3.2.27. Energy efficiency is an important parameter when comparing variable OPEX. Lower efficiency results in the use of more fuel to produce a planned amount of megawatt hours, consequently, increasing the variable cost. See table A7 in the appendix for more details regarding variable OPEX for thermal plants. Table 3.6 illustrates a short extract.

Table 3.6: Brief LCOE variable definitions for OPEX Variable Thermal

Thermal OPEX Variable (coal)			
Power plant detail	Variable OPEX USD per MWh	Comment	Source
Subcritical coal	37	35 set as a start value	(EIA, 2018b)
Supercritical coal	35	35 set as a start value	(EIA, 2018b)
Ultra-supercritical coal	31	35 set as a start value	(EIA, 2018b)

For fixed OPEX, the outcome is different. The constant expenses for operating the more modern technologies demonstrate a higher cost-level. The fixed OPEX for subcritical, supercritical and ultra-super critical are 28, 38 and 45 USD per MWh respectively (table 3.7).

Table 3.7: Brief LCOE variable definitions for OPEX Fixed Thermal. * Source used as guideline

Thermal OPEX Fixed (coal)			
Power plant detail	Fixed OPEX USD per MWh	Comment	Source
Subcritical coal	28	*	(WECC, 2017)
Supercritical coal	38	*	(WECC, 2017)
Ultra-supercritical coal	45	*	(WECC, 2017)

3.2.1.3 Fuel Cost

OPEX for a coal power plant includes fuel, labour and maintenance costs. Unlike capital cost which is fixed, a plant's OPEX depends on how much electricity the plant produces. The fuel cost is included as a dominating cost parameter within the variable OPEX for coal (appendix: table A7). The differences within variable costs for the different coal technologies, presented in the appendix under table A7 (power plant detail), is mainly caused by different energy efficiencies. Lower efficiency technologies consume more fuel during production, consequently resulting in higher variable costs.

3.2.1.4 Production

The production item in the PowerCube includes estimates of past, present, and future values. Most of the historical production is based on scouted values per country. The scouted values per country look at a country's total yearly installed capacity and then distribute this value among the assets installed capacity and estimated capacity factor (table 3.8), which is based on the annual operating hours. The difference (if any) between total estimated production and total actual production stated by renowned sources, such as IRENA, is presented as plugs. The plugs are used to calibrate the installed capacity, i.e. as a capacity benchmark to estimate what is missing bottom-up by adding plugs to compensate for the missing data. Future production is estimated by a similar methodology. However, the installed capacity for the future is predicted based on different production scenarios.

The capacity factors illustrated in table 3.8, are unit-less ratios between actual electricity output over a given period of time and the maximum electricity output (installed capacity) over the same period. The capacity factors used in the PowerCube are based upon country and technology basis. Hence, obtaining an average capacity factor for any type of renewable installations at different geographical locations.

Table 3.8: Capacity Factor for Renewable Sources in Germany

Germany Capacity Factors			
Energy Source Description	Capacity Factor	Year	Source
Onshore Wind	0.191	2012	(AGEB, 2012)
Offshore Wind	0.414	2018	(EN, 2018)
Solar PV	0.115	2012	(AGEB, 2012)

3.2.1.5 Cost Development

In order to estimate how the different costs, develop over time, *CAPEX year factors* are established in the PowerCube for renewable energy sources. These factors are used to estimate the annual decrease in cost for different CAPEX types. Most importantly, a cost development estimate from 2017 to 2100 for onshore wind and solar PV is established. For onshore wind, all CAPEX types are assumed to decrease by 0.5% annually. As solar PV is a less mature technology, the cost development is estimated to progress more intensely. The fabrication cost of solar PV modules is assumed to decrease by 2% annually, while the fabrication cost of inverters, and transport & installation costs are assumed to decrease by 1.5% annually. Offshore wind has shown a steady decrease in the cost since 1989, and future estimates are developed on the background of these values. 2013 is set to be the original year of cost, and the development from pre-2017 is estimated to be as follows: the fabrication and installation costs of the foundation are assumed to decrease by 1% annually, while the turbine fabrication cost is expected to decrease by 0.5% annually. The CAPEX annual factors are presented in detail in the appendix under table A9.

3.2.2 Database Construction

In order to perform the sensitivity analysis for the LCOE calculations, which is explained in the methods section 3.1, a substantial part of this project consists of expanding the database through the insertion of new variables for new kind of calculations and analysis in the MDS.

The PowerCube is currently a non-commercialised product in the testing phase. So far, the cube has shown very promising detailed data concerning plant-level capacities, production, and economics. However, in order to compute the sensitivity analysis scenario concerning CO_2-price for thermal sources (coal), the databases' MDS was required to be updated.

The emissions factors are plant specific. i.e. different coal assets with different feedstock and technology emit differently. The price of carbon (CO_2-price) influences the LCOE of coal, and the emission factor determines how much the LCOE is influenced. So the database is updated in order to improve the precision of the calculations.

3.2.2.1 CO_2 emissions

The ThermalCube (figure 3.7) contains detailed information on global thermal assets for power production, such as coal plants in the German electricity market. The CO_2-price scenarios include the current CO_2-price and IEA's CPS, NPS, and SDS explained in section 3.1.2 (Sensitivity Analysis). The unit of CO_2 price is $ per tonne of CO_2 emitted into the atmosphere during power production.

In order to compute the CO_2-price scenarios, CO_2 emissions per thermal asset have been calculated and included in the MDS. To estimate and calculate the emissions per asset, the feedstock first needs to be quantified. i.e. the amount of fuel-input for combustion. The following equation, Eq. (3.6) is used in order to calculate the feedstock:

$$Feedstock\ [Mt] = \frac{Power\ production\ [MWh]}{Plant\ efficiency\ [\%] \times Burn\ value\ \left[\frac{MWh}{tonnes}\right]} \qquad (3.6)$$

A feedstock is quantified in Megatonnes [Mt] and is estimated based on production [MWh], asset/technology efficiency [%] and burn value in energy per mass [MWh/tonnes]. The PowerCube and ThermalCube contain detailed power production data for the German electricity market. But, efficiency and burn value have been included in order to calculate the feedstock. Table 3.9 and 3.10 illustrate technological efficiency for different coal-fired technologies and burn value for different feedstocks respectively.

Table 3.9: Technological efficiency for coal-fired power production

Technological Efficiency (coal)			
Power plant detail	Technological efficiency (%)	Year	Source
Subcritical coal	34.3	2007	(Deutch, 2007)
Supercritical coal	38.5	2007	(Deutch, 2007)
Ultra-supercritical coal	43.3	2007	(Deutch, 2007)

Source: (Deutch, 2007)

Subcritical, supercritical and ultra-supercritical illustrated in table 3.9 comprises the majority of coal-fired technologies in Germany. Supercritical and ultra-supercritical applies to modern technology, which is usually put into service after 1990.

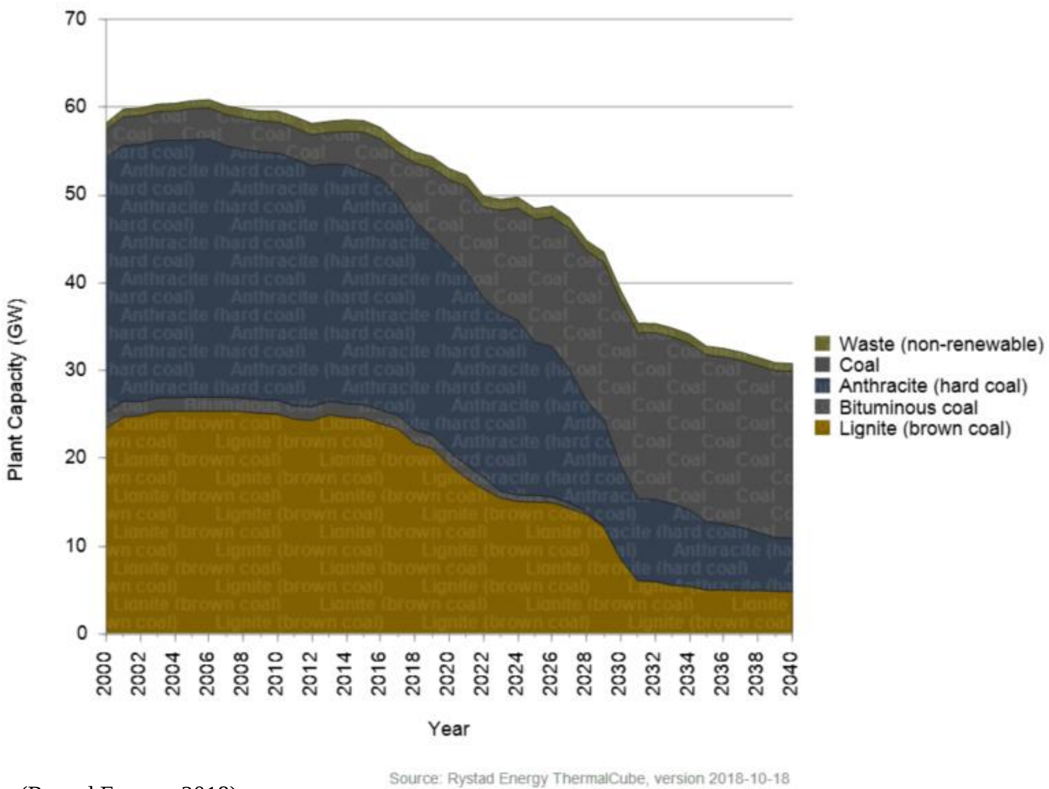
Table 3.10: Burn value for coal feedstocks

Burn Value			
Feedstock name	Feedstock type	Burn value (MWh/tonnes)	Source
Anthracite	Hard coal	8.743	(ASTM, 2018)
Bitumnious	Black coal	8.215	(ASTM, 2018)
Waste coal	Coal	7.950	(ASTM, 2018)
Subbituminous	Black/brown coal	5.756	(ASTM, 2018)
Lignite	Brown coal	4.735	(ASTM, 2018)

Source: (ASTM, 2018)

Table 3.10, presents the burn value for the most typical coal feedstock in Germany, whilst figure 3.1 illustrate the most standard fuel for coal-fired power production in descending order: anthracite, lignite, coal, bitumnious and waste coal with 23.7, 21.7, 6.7, 1,6 and 1.3 GW respectively for the year 2018 (figure 3.1). The feedstock named coal is estimated to be an average value of the other feedstocks. The majority of the coal capacity from 2018 and onwards is denoted as plugs, i.e. a Rystad Energy research and analysis estimate for the installed capacity until the year 2040

Figure 3.1: Cumulative installed capacity of coal-fired power production in the German electricity market 2000-2040



Source: (Rystad Energy, 2018)

Figure 3.1, is an excerpt from the ThermalCube, illustrating the net installed power generation capacity (GW) of coal-fired power production in Germany from 2000 until 2040. Forecasted values after 2018 are estimations based on installed capacity per feedstock. However, it is worth mentioning that the 26th of January, Germany's coal exit commission announced a complete coal-phase out before 2038. This is not presented in the forecast in this report.

When feedstock per asset is known and inserted into the database, the asset-based CO_2 emissions can be calculated through Eq. (3.7).

$$CO_2\ emissions\ [Mt] = Feedstock\ [Mt]\ \times\ CO_2\ emission\ factor\ \left[\frac{tonnes\ CO_2}{tonnes\ feedstock}\right] \qquad (3.7)$$

Different fuels (feedstock) emit different amounts of CO_2 relative to the energy they produce during combustion. In order to analyse CO_2 emissions across feedstocks, the amount of CO_2 emitted per unit of energy output is included in the calculations, this is known as the *CO_2 emission factor* (Eq. (3.7)). The amount of CO_2 produced when a fuel is burned is a function of the carbon content of the fuel. The higher the carbon content, the higher the CO_2 emission factor (King, 2018). The CO_2 emission factor are based upon the U.S. Energy Information Administration estimates, EIA (2016).

Table 3.11: CO_2 emission factor for different coal feedstocks

CO_2 emission factors				
Feedstock	Type	Carbon content (%)	Emission factor (tonnes CO_2/tonnes feedstock)	Source carbon content (c.c) emission factor (e.f)
Anthracite	Hard coal	87	2.340	c.c (King, 2018) e.f (EIA, 2016)
Bitumnious	Black coal	77-87	2.030	c.c (King, 2018) e.f (EIA, 2016)
Waste coal	Coal	77 (average value)	1.906	c.c (King, 2018) e.f (EIA, 2016)
Subbituminous	Black/brown coal	71-77	1.530	c.c (King, 2018) e.f (EIA, 2016)
Lignite	Brown coal	60-70	1.149	c.c (King, 2018) e.f (EIA, 2016)

Table 3.11 illustrates the emission factor for the different fuel feedstocks used for coal-fired power production in the German power generation industry. These variables are applied to the ThermalCube in order to include the CO_2 price in the calculated scenarios (table 3.1).

3.2.3 Overview and Summary Statistics

3.2.3.1 Variables Summary

In order to compute the LCOE and to perform a sensitivity analysis, a few definitions are explained and summarized in the table below.

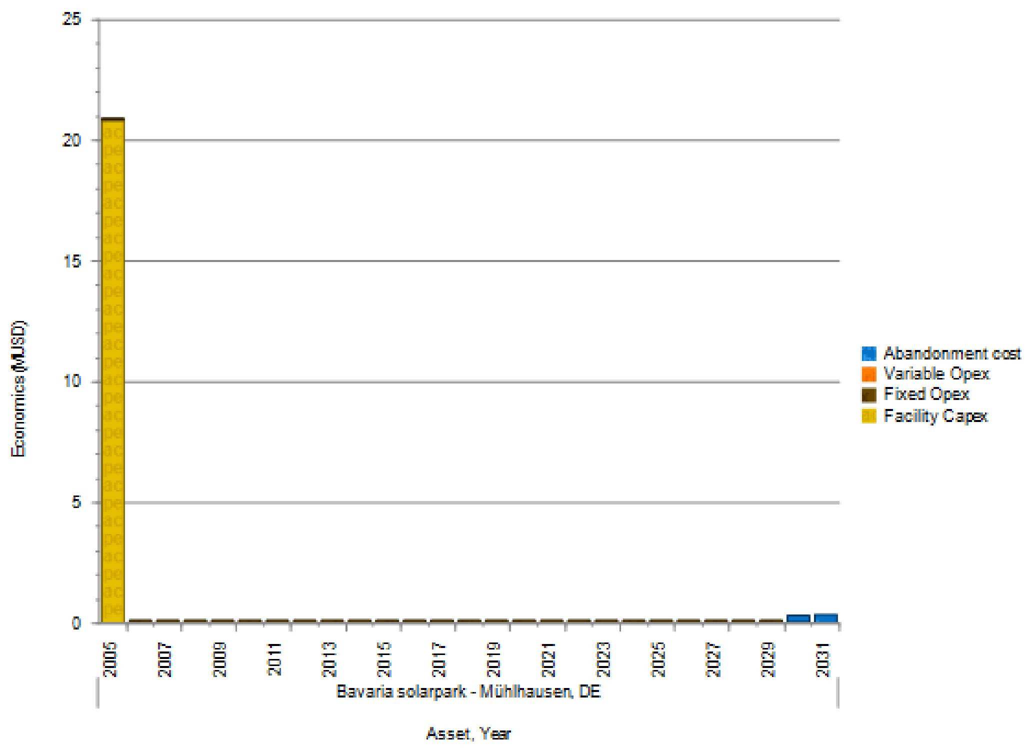
Table 3.12: Summary of variables

Variables explanation summary	
Facility CAPEX	Facility CAPEX refers to a company's spending on a physical facility asset, in this case, the power plant. CAPEX is a major part of a power producing company's investment spending and cash flow. I the power generating industry physical assets are essential for the production of electricity.
Fixed OPEX	Fixed OPEX, operational expenditure, is the 'constant' general expenses which the asset need to spend in order to stay in operation. The fixed OPEX does generally stay the same depending on the level of output. For a power producing company, these expenses are often related to operational and maintenance (O&M) costs, such as salaries, taxations, and regular maintenance.
Variable OPEX	Variable OPEX is the 'changing' general expenses which the asset need to spend in order to stay in operation. The variable OPEX increases with output and is often referred to as fuel cost and cost of the variable labour force, given changing output.
Abandonment cost	Abandonment cost is the cost associated with the abandonment of a power producing asset. Hence, removal of equipment, infrastructure, facilities, or any necessary environmental clean-up.
Interest rate	Interest rate is the cost of borrowing money expressed as a percentage of the loan amount. Interest rates are the primary tool for measuring how much return lender will get.
Production	Production is the annualized amount of electricity produced. Production is expressed in the predefined unit of energy, which includes kWh, MWh, GWh, and TWh.
Capacity	Capacity is referred to as plant capacity and is the maximum gross production capacity of the power plant year by year over the plant's lifetime. Plant capacity is time-dependent and can be expressed as a function of year and month. Capacity is expressed in predefined units of power which include KW, MW, GW, and TW.
Capacity factor	Capacity factor is the ratio between actual production for a time period and the maximum capacity over the same period of time. The capacity factor is a unitless integer, which is often referred to as fuel efficiency for conventional power generation, and amount of wind and/or solar resources for RE power generation.
Net Present Value (NPV)	NPV is the value of a specific stream of future cash flows presented in today's dollars. NPV can be calculated by comparing an initial cost of a project, to the total value of future revenue a specific project creates. Hence, evaluating whether a project is worth doing.

3.2.3.2 Cost Structures

Rystad Energy's PowerCube is the software which contains the data for comparing the levelized cost of the different energy sources. The data does not include wholesale electricity prices but is primarily focused upon the cost aspect. Levelized cost of renewables, such as solar and wind assets, demonstrate different cost structures compared to the levelized cost of a typical thermal plant, such as a coal asset. The following cost structure examples are extracted from the PowerCube in order to illustrate the cost distribution per technology of three mainstream power plants in the German electricity market. This is conducted with the aim of presenting the overall cost of plants that have the most common installed capacity and economic values.

Figure 3.2: Cost structure of Bavaria Solarpark - Mühlhausen

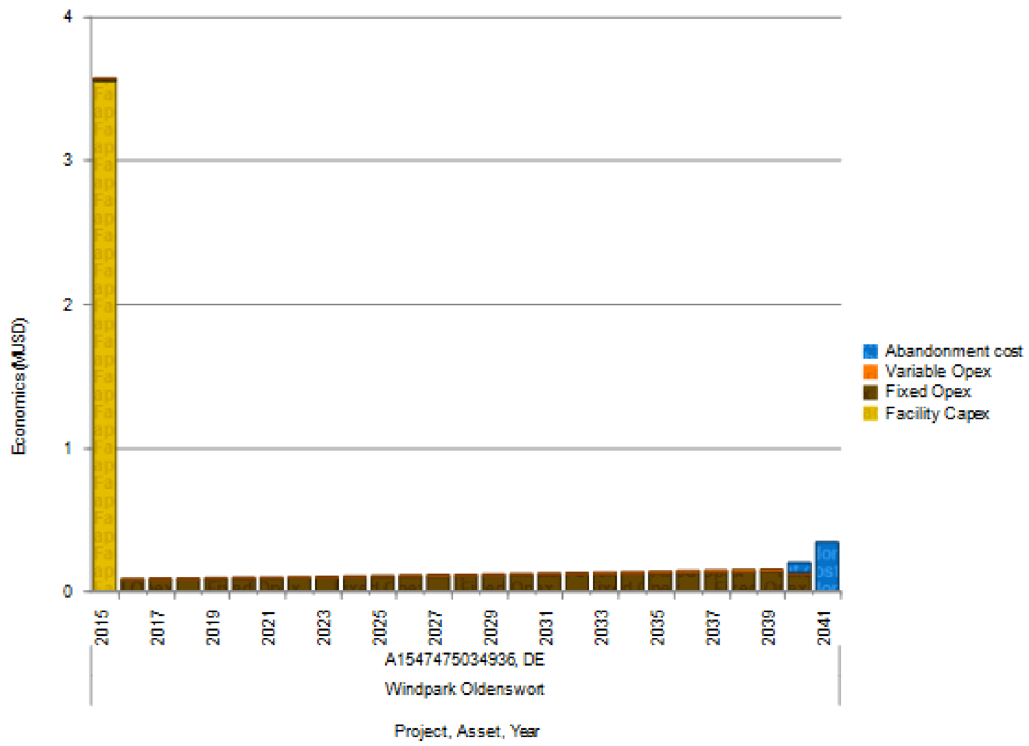


Source: (Rystad Energy, 2018)

Figure 3.2 illustrates an example of a typical cost structure for an average/medium-scale solar PV plant in Germany. This plant, Bavaria Solarpark (6.3 MW) was the largest PV power station in the world, at the time of its construction in 2005, in Mühlhausen Germany. The cost structure of a solar asset is typically illustrated through a large amount of capital expenditure (CAPEX) in the start phase (2005), such as facility costs and capital cost, and relatively constant and low OPEX throughout the lifetime (2006-2029). This is followed by an abandonment cost for decommissioning (2030-2031) the plant which is usually estimated to be roughly 20% of the facility cost for all renewable plants. The OPEX for solar plants is dominated by fixed OPEX, which is on-going O&M expenses such as module cleaning, manpower, etc. Bavaria Solarpark is no exception, as can be seen through the illustration of a typical cost structure. Connection to the electricity grid was performed by the regional German utility E.ON, with a 20-year power purchase agreement (PPA) under the German Renewable Energy Law (EEG).

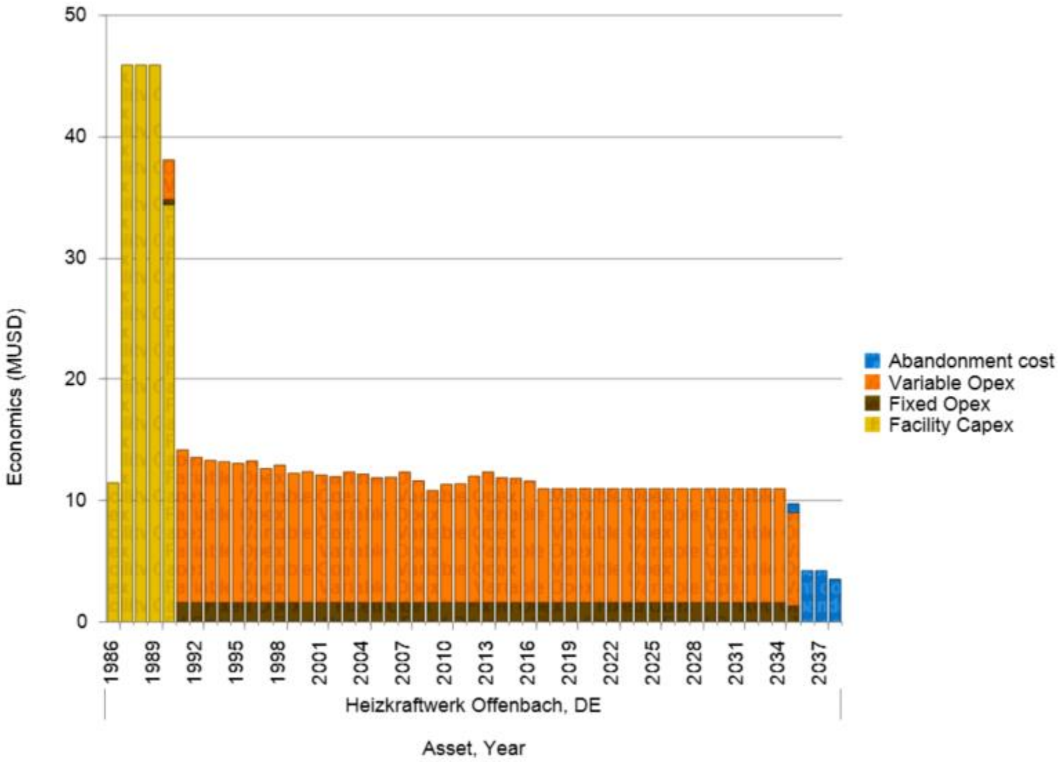
The cost structure for a typical wind asset provides a similar structure as for a solar plant. Figure 3.3, illustrates the cost structure for one (2 MW) out of six turbines comprising Oldenswort wind farm with an installed capacity of 12 MW, signifying an average/medium-scale wind farm in Germany. Similarly, there is a significant amount of CAPEX (facility and capital cost) in the start phase (2015), followed by a slowly increasing OPEX (2016-2040) until the initiation of an approximate 20% abandonment cost (2040-2041). The OPEX for a typical wind farm is slightly different than for a solar plant. First of all, the OPEX gradually scales in line with the age of the plant, consequently, estimating increased O&M expenses throughout the lifetime of the assets. Additionally, a wind farm typically includes a small amount of variable OPEX, which also increases with the age of the power plant.

Figure 3.3: Cost structure of Oldenswort Wind farm - Schleswig-Holstein



Source: (Rystad Energy, 2018)

Figure 3.4: Cost structure of Hkw Offenbach Power Station - Hessen

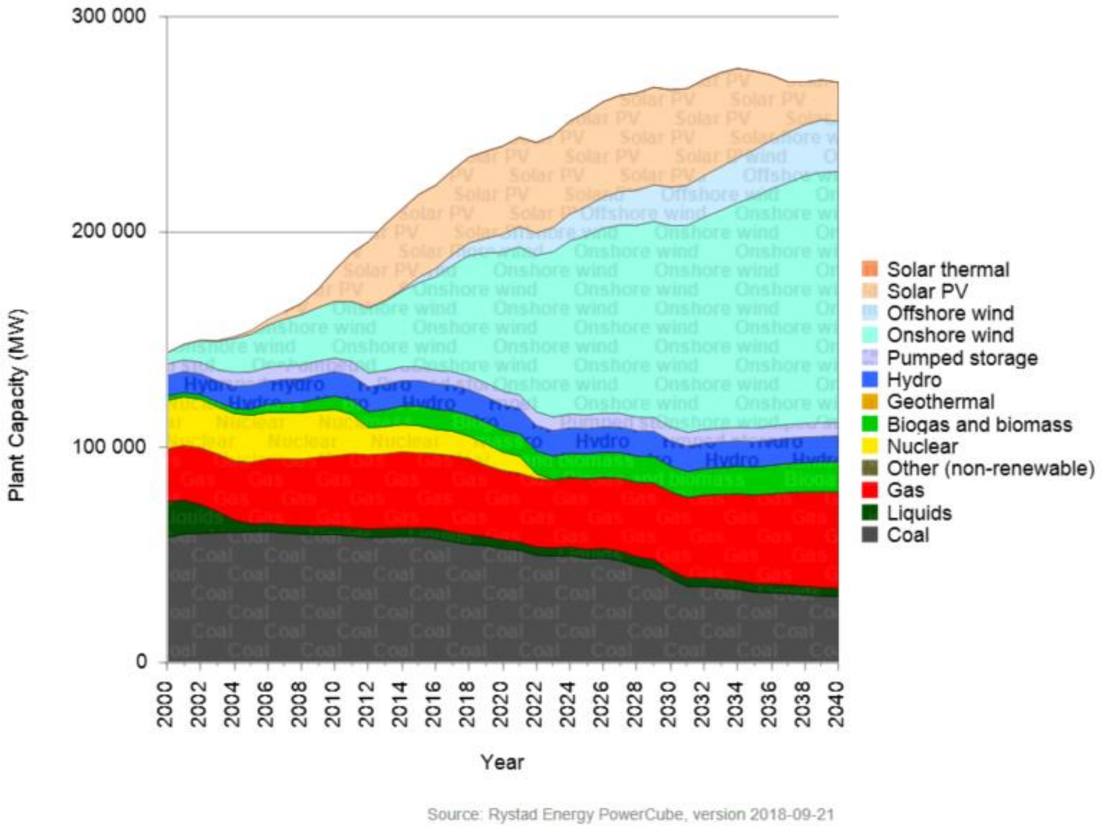


Source: (Rystad Energy, 2018)

The cost structure of a typical coal asset is different, figure 3.4, illustrates a cost structure for a coal plant. Offenbach Power Station is a bituminous-fired combined heat and power plant (CHP - heizkraftwerk), having an installed capacity of 64 MW, thus exemplifying a typical lower medium-scale thermal plant in Germany. The start phase includes a significant share of CAPEX, which is dominated by facility costs (1986-1990). The fixed OPEX are relatively easy to estimate, while the variable OPEX is a major part of the cost and is rather complex to evaluate. Fixed OPEX is relatively low costs such as capital cost, obtaining sitting permits, environmental approvals, etc. The variable OPEX are significant and are dominated by operating costs, such as fuel (cost of coal), human capital (labor) and maintenance (O&M) cost. Furthermore, the abandonment cost for large-scale industrial thermal plants is considered to be a substantial part of the total cost. From figure 3.4, it is noticeable that the annual variable OPEX is calculated since 1990 until 2016, and from 2017 to 2035 the values are presented as fixed estimates which are updated yearly, given sufficient basis for detailed calculations.

3.2.3.3 Installed Capacity

Figure 3.5: Cumulative installed capacity in the German electricity market 2000-2040



Source: (Rystad Energy, 2018)

Figure 3.5, is an excerpt from the PowerCube, illustrating the net installed power generation capacity (GW) in Germany from 2000 until 2018. The values from 2018 until 2040 are estimations of installed capacity per energy source. Hence, in the short-term, the values which are included within the next 5-10 years are based upon assets which are *in application*, *approved* or *under construction*. Thus, this includes assets which are known to be a part of the German electricity generation portfolio for the coming years. All power generation assets have an estimated lifetime, this is also taken into consideration as decommissioned plants need to be replaced in order to deliver the anticipated load in the market. The same goes for long-term estimations, however, the long-term analysis does also include future energy policy and the long-term approximations of developments in national demand, interconnector capacity and international power trade.

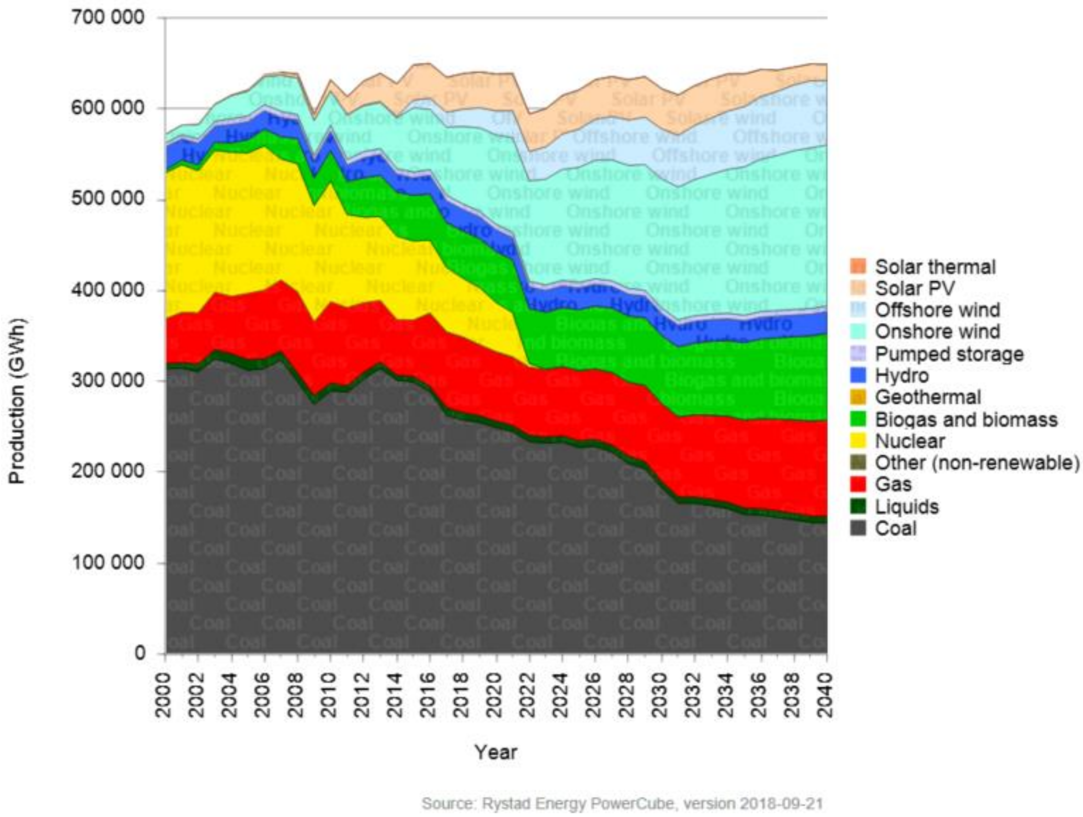
Figure 3.5 illustrates that, for the first time in 2018, the installed capacity of onshore wind was the single largest source of capacity, having 56.1 GW out of total 234.8 GW, consequently contributing 23.9% of the German power mix. In addition, Onshore wind capacity is estimated to obtain as much as 43.2% of the market in 2040 (116.4 out of 269.6 GW), followed by coal – 20.4% (54.9 GW) and gas – 13% (35.2 GW). Note that these numbers do not include Germany's coal exit commission's recent (January 2019) decision to phase-out all coal-fired power stations by 2038. This is further explained in section 3.2.3.4.1 below.

Another aspect worth commenting on is the total decommissioning of nuclear plants by 2022. Presently, it seems quite likely that *Nuclear phase-out #2* initiated in 2011 will be carried out according to the plan and on time. Today, only 7 operational nuclear reactors exist in Germany, out of a total of 36 reactors which have been decommissioned in the last 10 or more years. These reactors are all having a date of final shutdown in either 2020, 2021 or 2022.

There has also been a public and political push to phase-out coal-fired power generation. However, due to the coal plants important role in delivering cheap and flexible base-load electricity, the decisions have not been taken before January 2019. The future of the coal industry has been a more complex topic. The German lignite mining industry alone employs as many as 20,000 people. Compared to the 340,000 employed directly in the renewables industry (2018), this is a small number. Nevertheless, coal workers have traditionally been well organized in labor unions with close connections to political parties (DW, 2017a). Therefore, it was estimated that coal would continue to be an important participant within the German electricity mix going forward. Excluding the planned coal phase-out in 2038, Rystad Energy research and analysis estimates that the installed capacity will be reduced from 54.9 GW in 2018 to 30.8 GW in 2040. i.e. a reduction from 23.4% to 11.4% market share for 2018 and 2040 respectively.

3.2.3.4 Production

Figure 3.6: Annual production in the German electricity market 2000-2040 per energy source



Source: (Rystad Energy, 2018)

In order to produce an extensive overview of the market and the database, it is equally important to look further into the annual development within power production, as well as yearly estimates for the same time horizon (2000-2040). The power production data provide an actual picture of how much each energy source contributes to the energy mix based upon an estimate of how many full-load hours each technology has per year.

Figure 3.6, is also modelled in the PowerCube, illustrating the annual production (GWh) per energy source. Analysing a power production point of view provides a different perspective upon the situation. Onshore wind was the largest source of installed capacity in 2018, in addition to demonstrating to be the source with the most significant growth factor (before solar PV) for the next 22 years. However, in 2018 onshore wind accounted for only 13.3% of the electricity production with 85.2 GWh versus a national total of 640 GWh. Simultaneously, coal-fired electricity production included as much as 257.4 GWh, demonstrating 37% of the total production, which is 32.6 GWh more than all the renewable energy sources combined (224.8

GWh), including solar thermal, solar PV, offshore wind, onshore wind, pumped storage and hydro. Towards 2040, the picture is predicted to be quite different. The downscaling of coal-fired generation is estimated to be replaced by an increased share of gas-fired and biomass (biogas) generation for the dispatchable units. Furthermore, a significant increase in production from non-dispatchable energy sources such as solar PV, offshore and onshore wind is foreseen. However, figure 3.6, indicates that coal-fired generation is estimated to be the single most important source of power production until the year 2035, which is denoted as the first-year onshore wind bypasses coal with 163.1 GWh versus 153.6 GWh. Similarly, as with installed capacity, the coal phase-out in 2038 is not included in figure 3.6.

3.2.3.4.1 Coal Phase-out

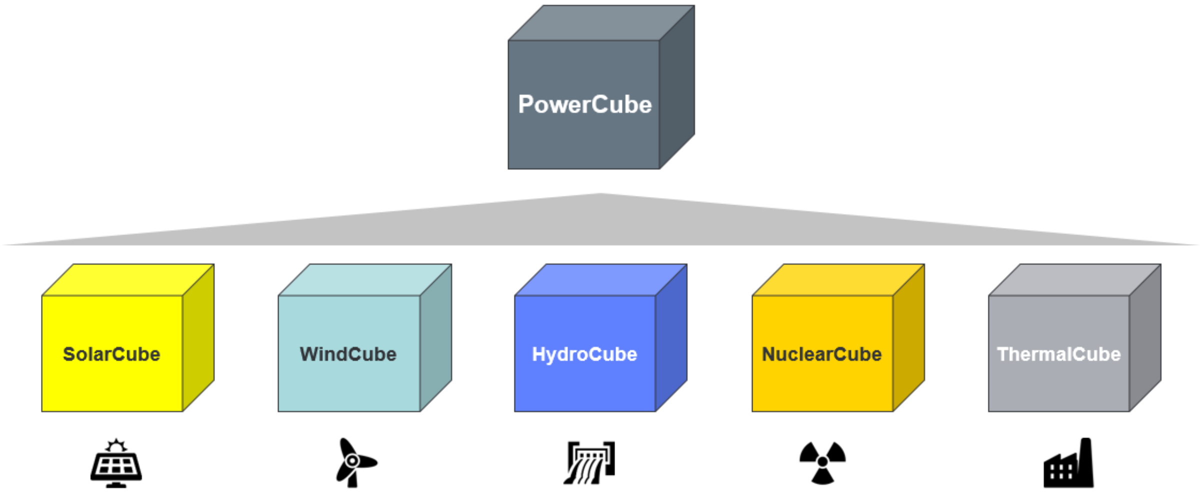
In January 2019 Germany's coal exit commission ruled in favour of phasing out all coal-fired power stations by 2038. However, Germany's sluggish progress towards its renewable energy goal remains overshadowed by smog from its long history of coal reliance. About a quarter of the country's ~640 TWh of electricity generation was supplied by solar and wind in 2018, while over 37% was supplied by coal - specifically, lignite coal, the dirtiest and most pollutant variety. And the shift to renewables will be slow. Germany plans to transition away from coal power in measured steps, to preserve the security of supply.

By moving away from coal in phases, it hopes to maintain affordable consumer power prices and insulate mining regions from the economic shock of a sudden market shift. Germany currently has an installed utility-scale coal-fired capacity of 40.8 GW, 12.5 GW of which will be decommissioned before 2022, and an additional 12.5 GW before 2030. Germany hopes to decommission the remaining 15.8 GW before 2035, and certainly by 2038 at the latest (Hvalbye, 2019). However, it is important to emphasise that the coal phase-out and its measured steps are not included in this report but is an important aspect to consider for further research.

3.2.3.5 PowerCube

The renewables (hydro cube, wind cube, and solar cube), nuclear and thermal cube comprise the PowerCube database (figure 3.7). The PowerCube is plant-level data collected by internal Master Data Services (MDS). Figure 3.7 illustrates the workings of the PowerCube. In each topical cube, assets are named plants. These cubes are used for deep dives for the specific energy types. E.g. for market analyses, or acquisitions. The PowerCube contains assets from the topical cubes with some lower granularity (capacity, production, economics, etc.). This is suitable for analysing different types of energy mix.

Figure 3.7: Cube illustration of Renewable Cubes (topical cubes) and PowerCube



Source: (Rystad Energy, 2018)

MDS gives simple access to all input tables and enforces business rules. MDS is an advanced form for Excel Add-in, which offers: security; historical updates (able to rollback); user manageable business rules on the input side; and versioning. MDS is an integrated part of SQL Server, and all necessary programming for the scenarios are performed using the standard SQL language.

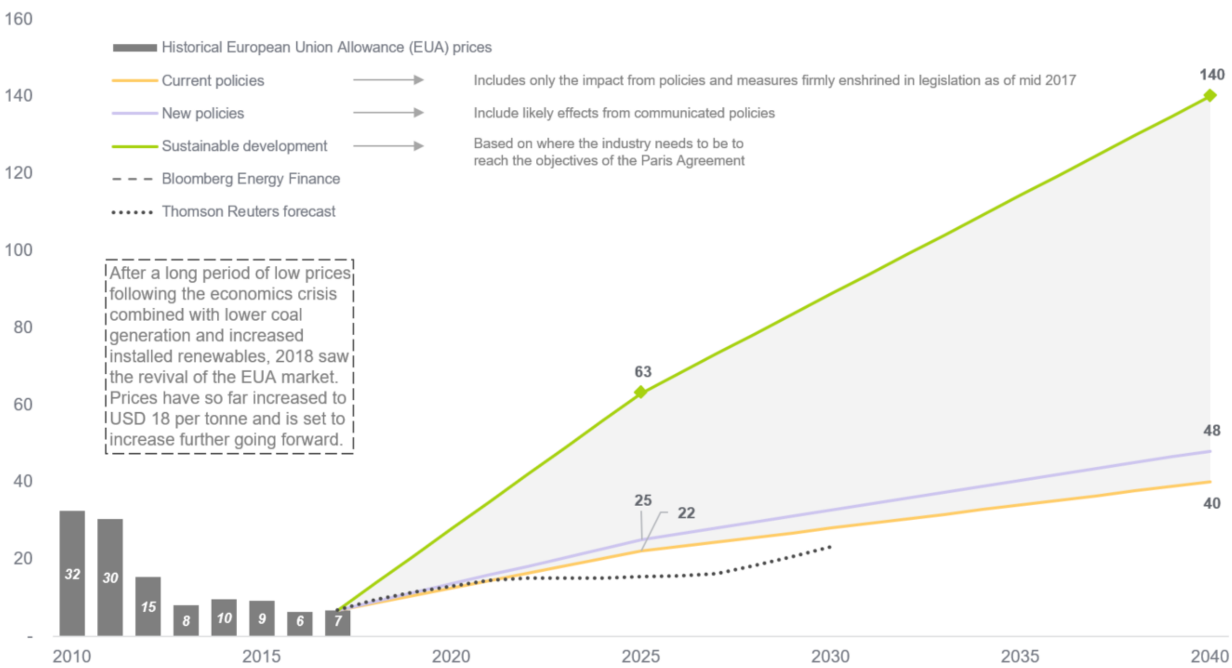
The analytical approach includes programming the scenarios presented in table 3.1 (Sensitivity Analysis Scenarios). Coding within the internal master data services allows for computing, analysing and illustrating the obtained results via the PowerCube. This approach is recognised to obtain a higher quality of data output, compared to the export of raw data into an optional programming software for analysis. This is mainly caused by the complexity of the database and a vast amount of data points available in the cubes.

3.2.3.6 CO_2 price

Germany and 30 other European countries (all 28 EU countries in addition to Iceland, Liechtenstein and Norway) have initiated the EU emission trading system (EU ETS). This limits emissions from more than 11,000 heavy energy-using installations and concerns approximately 45% of the GHG emission in the EU. The EU ETS function based upon the *cap and trade* principle: a cap is set on the total amount of certain GHG that can be emitted. With time, the cap is reduced, driving emission reduction. With the cap, companies receive or buy emission allowances. The allowances can be traded as EUA with other companies if needed. Prior to a production year, a company must submit sufficient allowances to cover its total emissions, failing to do so will result in substantial sanctions, in the form of fines. Reducing emissions can either result in saving allowances for future needs or trade the allowances with companies which are short. Trade of EUA ensures that emissions are reduced where it costs the least to do so. Additionally, the carbon price encourages investment in clean, low-carbon technologies (EC, 2018).

Table 3.1, which illustrates the sensitivity analysis scenarios, demonstrates the CO_2-price development implemented in this report. The figure below (figure 3.8) establish and compares the different scenarios and forecasts.

Figure 3.8: Price per tonne CO_2 equivalent. USD per tonne (real)



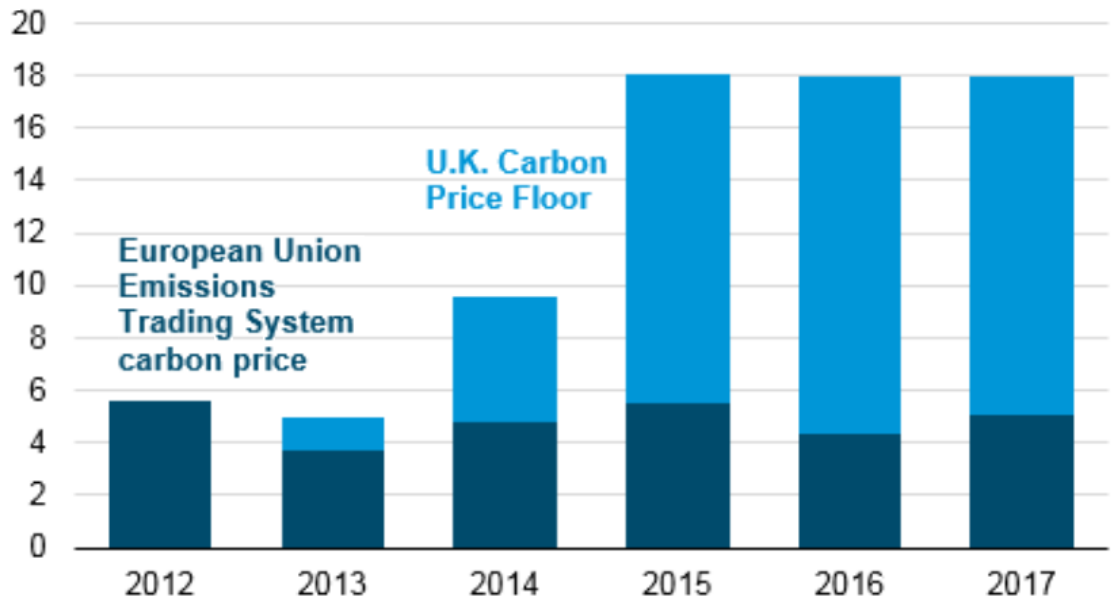
Source: (Rystad Energy, 2018)

From figure 3.8, it is noticeable that IEA, through the *sustainable development scenario*, estimates that $140 per tonne CO_2 is required in Europe by 2040 to reach the 2-degree target. However, it is worth mentioning that this is one of several requirements, and the EIA (2018a), predicts that in this scenario there is a 50% chance of limiting temperature rise to below 2 degrees Celsius. The SDS is acknowledged to be the most aggressive policy scenario for the

European Union. The scenario is primarily based on where the industry needs to be to reach the objectives of the Paris Agreement.

The project hypothesis, as well as many coal utility owners, assume that SDS will result in a complete shut-down of all coal-fired assets in the EU and Germany due to soaring operational costs. This assumption is based on the current situation in the UK. The UK introduced the Carbon Price Floor (CPF) on 1 April 2013. CPF is a UK Government policy implemented in addition to the EU ETS, consequently, promoting carbon pricing at levels which highly encourage low carbon investments. Electricity generators in the UK have to consider a carbon tax consisting of two components: the EU ETS price (EUA); and the Carbon Support Price (CSP), which together comprises the carbon floor price target (Hirst, 2018). The figure below illustrates the UK carbon prices comprising the CPF (figure 3.9).

Figure 3.9: United Kingdom carbon prices (fiscal years 2012-2017). Pounds sterling per metric ton carbon dioxide



Source: (EIA, 2018a)

Currently, the UK CPF is 18 GBP per tonne CO_2 and has been at this level since 2015, this is equivalent to approximately $24 per tonne, where it will remain until 31 March 2020, at least (the fiscal year 2019). Since the introduction of the CPF, there has been a significant decline in electricity generation from coal-fired technologies in the UK. The year 2015 marked an important point of inflection, the CPF of 18 GDP per tonne ($24) was far from economically sustainable for coal-fired generation. Since 2012, the electricity produced from coal has declined from 42% to 7% in 2017. Additionally, the UK government introduced an *implementation plan* in January 2018, consequently, initiating coal-fired power plant phase-out by 2025 (EIA, 2018a).

Based on the experiences and findings from the UK electricity market, and even though this analysis is only comparing new renewables with existing coal, the results are believed to provide similar characteristics for Germany. It is also important to have in mind that the EUA CO_2-price has been above \$20 between August and October 2018, and from mid-December until now (early May 2019) with a few exceptions. Persistent CO_2-price of roughly \$20 underline the importance and relevance of not only including CPS and, NPS but also evaluating how the SDS affects the forward-looking coal industry.

3.2.3.7 Assumptions

3.2.3.7.1 Intermittency

The intermittent nature of renewable energy sources leads to an important question regarding the competitiveness of the technologies compared to dispatchable technologies, such as coal-fired power plants. In a real case, an investment decision which evaluates whether or not to invest in renewables (solar and wind) versus investing in coal, includes some complex aspects. First of all, a coal-fired power plant is a dispatchable technology, therefore, achieving increased flexibility and availability. This makes it a lucrative alternative in terms of energy security compared to the unpredictable nature of wind and solar technology.

This report only evaluates the competitiveness of different technologies in the form of levelized cost. It is assumed that solar, wind and coal has the same systemic characteristics. i.e. all three technologies operate under the same circumstances with full baseload and dispatchable abilities providing the same quality of electricity.

Preferably an LCOE analysis of intermittent technologies should include the additional external system costs, such as necessary grid updates and storage capabilities for it to be comparable with dispatchable coal. On the other hand, it is also worth mentioning that coal-fired generation should include the substantial cost of climate externalities. These two aspects are worth considering for further work including a sensitivity analysis of LCOE estimations for solar, wind, and coal.

3.2.3.7.2 Electricity Price

Given that the project scope estimates evaluates and compares the levelized cost of different power producing technologies, it is important to acknowledge that the different values electricity sells for are not included in the analysis. It is worth mentioning this as a problem, as it is an important detail in considering investments in new energy capacity.

Electricity generation from RE sources, especially wind and solar, enables the sale of their electricity output at a low price, given the small amount of OPEX. However, the security of supply from dispatchable technologies could in some cases be awarded through policies which guarantee the asset a fixed competitive electricity price over a long period. This would result in a long-term hedge for coal plants against low and volatile electricity prices in electricity markets with a high share of intermittent generation.

If such policies are not in place in markets with substantial RE sourced supply, coal assets will in the long-term struggle to capitalize on the vast amount of sunk CAPEX. These aspects are directly related to policy regimes in different electricity markets and will be examined further in chapter 4, in relation to the computations.

3.2.3.7.3 Weighting

Another aspect worth noting is how the individual assets are weighted in the analysis. Levelized cost estimates include the present value of the cost of generating energy (USD) divided by the present value of the energy output (MWh). i.e. the plant-level LCOE is a ratio. Additionally, if a bundle of similar technology assets is analysed together, the resulting group-level LCOE is a weighted average of plant-level LCOEs, where the weights are given by production levels.

4 Empirical analysis: Results & Discussion

The application of LCOE within the scope of this paper is unique in that it is used to compare existing assets, with new assets, by manipulating two key variables to ascertain the point at which it becomes cost competitive to switch from a coal asset to a renewable asset, within the context of the German energy market. The two key variables manipulated within this methodology are CAPEX-reduction for renewables and CO_2-price increase for coal. This is referred to as a sensitivity analysis. As new assets are compared to existing assets, therefore LCOE for new assets is calculated using operational costs (OPEX) plus capital cost (CAPEX), while LCOE for existing assets considers only operational cost (OPEX) as capital cost is considered sunk. This analysis is useful when making a simplified valuation for an electricity-producing asset, which may be used by a firm involved in an investment decision or a political entity.

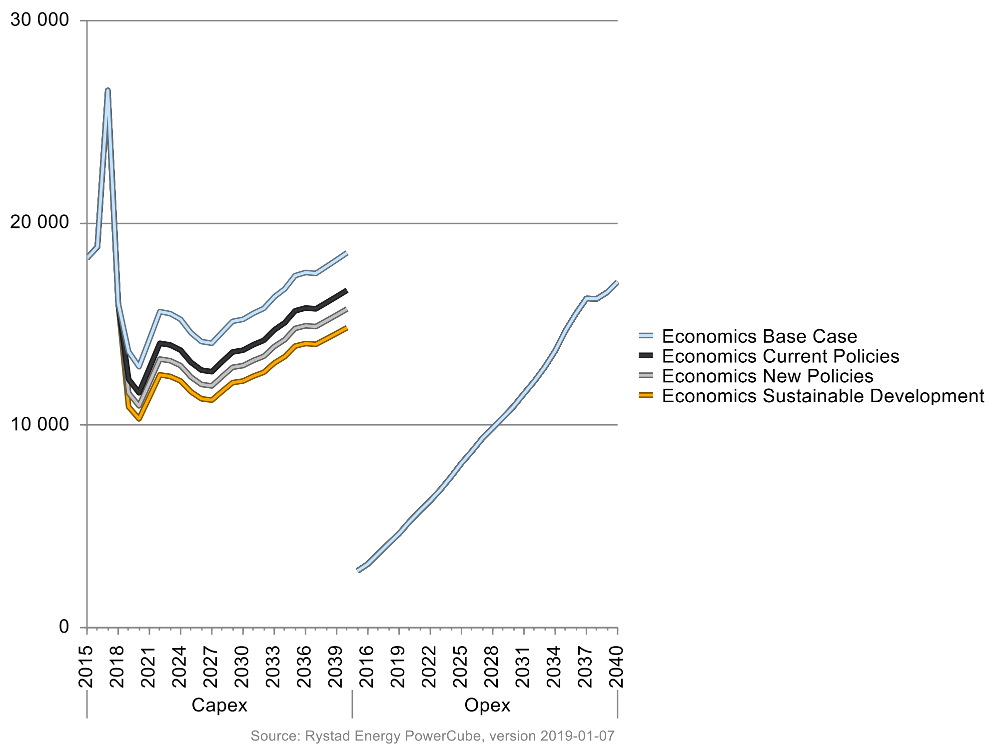
It is worth mentioning that all economic values are real terms, not nominal terms. This includes OPEX and CAPEX in MUSD and LCOE in USD per kWh. This means the results of the calculation (costs) do not take inflation into consideration going forward, making the results more transparent.

4.1 Overview

4.1.1 Scenarios

The analytical results in section 4.2, will investigate some scenarios which possibly can be the future situation for Germany. In order to introduce the analytical results and the scenarios which are implemented for the renewable CAPEX and for the CO_2-price of coal, the following figures illustrate the aggregate development within costs for solar, wind (figure 4.1) and coal (figure 4.2) in Germany. The aggregate numbers of CAPEX and OPEX are also included to present an overview of the magnitude of the costs associated with RE and coal, whilst also presenting a forecasted trend of spending in the German electricity market.

Figure 4.1: Aggregate CAPEX and OPEX for solar and wind in MUSD in Germany

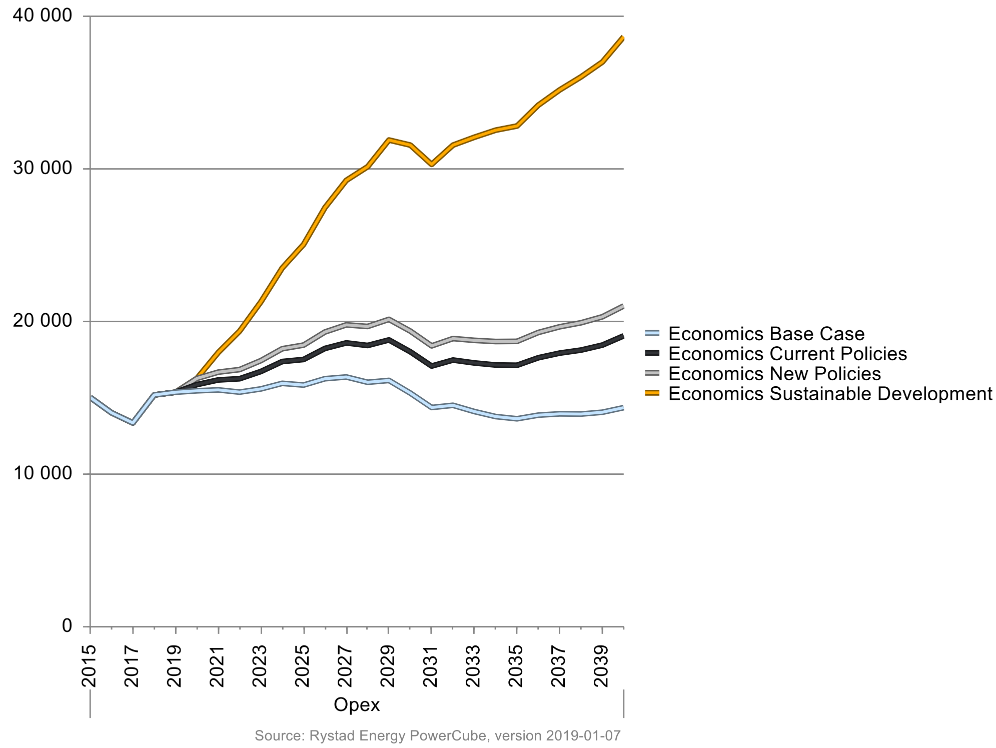


Source: (Rystad Energy, 2018)

Figure 4.1 illustrates the aggregate capital expenditure and the operational expenditure for solar and wind (RE) from 2015 to 2040. Aggregate numbers reflect the predicted numbers of installations and the predicted costs per installation. For renewables, the investment costs per installation are varied in step with the scenarios while keeping the number of predicted installations constant. i.e. the CAPEX item on the LHS illustrates the economics profile in MUSD for the Base Case (blue - current situation), RCPS (black - 10% reduction), RNPS (grey - 15% reduction), and RSDS (orange - 20% reduction) for CAPEX-development scenarios which are presented in table 3.1 (Sensitivity Analysis Scenario). The blue line represents the actual scouted values between 2015 and 2018, and the forecasted Base Case values between 2018 and 2040. The spike in 2017 of 26,550 MUSD is explained by a significant amount of installed solar and wind capacity of 50.78 GW versus 28.3 GW and 30.2 GW for 2016 and 2018 respectively (appendix: table A10). The black, grey and orange lines represent 10%, 15% and 20% forward-looking CAPEX-reduction starting in 2018, for solar and wind assets in Germany. The difference between a situation with a standard forecasted CAPEX-reduction (base case) and a scenario with 20% CAPEX-reduction (RSDS) is slowly increasing from 2018 until 2040. In 2040 the spread is estimated to be as much as 3,706 MUSD.

The development of operational expenditures for renewables, presented in the same figure (figure 4.1, RHS) does only consider the Base Case from the PowerCube. From the illustration, a significant increase from 2,806 MUSD (2015) to 17,085 MUSD (2040) is noticeable. The fast increase to high levels of OPEX is mainly caused by a forecasted increase in fixed OPEX and increased decommissioning cost for renewables. Decommissioning costs are included in the OPEX estimations and each asset is assumed to obtain a certain lifetime. Consequently, a boom in installations results in a boom in decommissions roughly 25 years after installations. The spike of 2037 and the top of 2040 are both approximately 25 years after the solar installation boom in the time period of 2010-2012 (appendix: table A10), and the wind installation boom in 2017 (appendix: table A11). Likewise, the fixed OPEX (and OPEX in general) correlates with the installed capacity. Growing installed capacity in wind (particularly onshore) results in a significant increase in overall OPEX when taking more assets into account, which is illustrated in figure 4.1.

Figure 4.2: Aggregate OPEX for coal in MUSD in Germany



Source: (Rystad Energy, 2018)

Figure, 4.2, shows the aggregate economic development in the form of operational expenditures of all coal-fired assets in Germany. The Base Case considered in this report includes $16 per tonne CO_2 as the CO_2-price, while *current policies scenario* (CPS), *new policies scenario* (NPS), and *sustainable development scenario* (SDS) includes the CO_2-prices illustrated in table 3.1 or summarized in the table below. Table 4.1 summarises the CO_2-price for 2020, 2030 and 2040 per scenario based on IEA's assumptions for the EU.

Table 4.1: IEA's CO_2-price assumptions per scenario for the European Union

IEA's CO_2-price assumptions per scenario		
IEA Scenario	Year	CO_2-Price (USD/tonne CO_2)
CPS	2020	18
	2030	30
	2040	40
NPS	2020	20
	2030	37
	2040	50
SDS	2020	20
	2030	100
	2040	140

Source: (IEA, 2015b).

As presented in section 2.2.2 (Estimates of Levelized Cost of Electricity), figure 2.8 and in section 3.1.2 (Sensitivity Analysis), the CO_2-price is recognised to play a central role for the total operational costs for a coal-fired power plant. Figure 4.2 is no exception; the spread of the different scenarios clearly illustrates how sensitive the OPEX is to only vary the CO_2-price. Similarly, as with the CAPEX-development for renewables, the difference between the Base Case and the IEA's CO_2-price scenarios is increasing with time. E.g. the comparison between the Base Case situation with an implemented constant CO_2-price of $16 per tonne CO_2, and the *new policies scenario* with $50 per tonne CO_2 in 2040 demonstrates a total OPEX spread of 6,664 MUSD in the German electricity market for this year. The most aggressive policy scenario, namely the *sustainable development scenario* discussed in detail in section 3.2.3.2, include a CO_2-price assumption of $140 per tonne CO_2 in 2040. This corresponds to a difference in total OPEX of 19,598 MUSD and 24,302 MUSD compared to the *current policies scenario* and the Base Case situation respectively for 2040. As it is difficult to make sense of the aggregate numbers, they are merely included to present the magnitude of the cost associated with the operational cost for coal. The following section concerns the more informative cost per unit of electricity produced (LCOE).

4.1.2 LCOE Comparison

This section illustrates separate LCOE values, and forecasted values, for solar, wind and coal, with and without adjusting the CAPEX for renewables and CO_2-price for coal. All LCOE values in this report, including the LCOEs in figure 4.3 are average LCOEs per technology which are weighted by production. Figure 4.3 is presented in order to evaluate the current base case situation in Germany.

Figure 4.3: LCOE for Solar, Wind (onshore and offshore) and Coal in USD per kWh from 2000 until 2040

Source: (Rystad Energy, 2018)

Figure 4.3, illustrates and compares the LCOE for solar, wind and coal in USD per kWh from 2000 until 2040. The figure shows separate illustrations for scouted values on the LHS and future values on the RHS. The LCOE values include historical scouted values until the year 2018, and estimated values from the year 2019 and onwards. The values for all three energy sources are without any scenarios, thus illustrating the current Base Case situation. The LCOE for solar, wind, and coal shows a steady development going forward from 2022, whilst all three LCOE's obtains some volatility in the period from 2018 to 2022. These fluctuations are explained by some existing and forecasted expensive installations, which are illustrated as outliers in the dataset. Consequently, disrupting the steady increase.

Worthy of particular appraise, is the substantial and rapid cost reduction of solar PV. The levelized cost of solar PV has decreased from roughly 2.2 USD per kWh in 2000 until 0.15

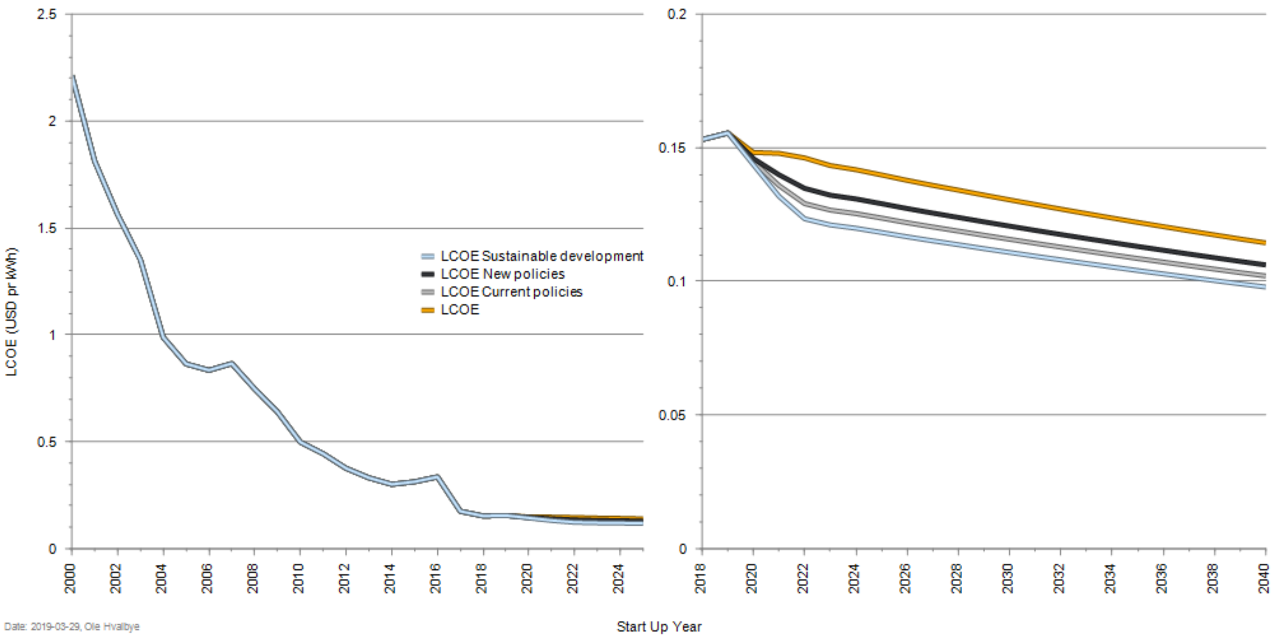
USD per kWh in 2018, which indicates an LCOE decrease of 93% in 18 years. The LCOE for wind, in this case, is presented as an average value between onshore and offshore wind assets in Germany, the difference between them is illustrated in detail in section 4.1.2.2 (figure 4.5). The LCOE for both wind and coal are nearly identical from 2000 until 2018 and has decreased from around 0.14 USD per kWh to roughly 0.13 USD per kWh respectively. From 2018, going forward the LCOE for coal is assumed to be stable at 0.13 USD per kWh in 2040, whilst wind and solar PV are estimated to gradually decrease to about 0.125 and 0.11 USD per kWh respectively in 2040.

It is noticeable that with the current Base Case situation (without scenarios), wind and solar PV are forecasted to obtain a lower levelized cost than coal from 2029 at 0.13 USD per kWh. The same year also illustrates the point of competitiveness between solar PV and onshore wind. i.e. going forward from 2029, solar PV is forecasted to be cheaper than wind.

4.1.2.1 Solar PV

Section 3.2.3.3 illustrate that the installed capacity of solar PV in the German electricity market has increased from roughly 100 MW in 2000, to about 40,000 MW in 2018, and Rystad Energy research and analysis expects this to peak in 2029 with 45,320 MW installed capacity. This trend has been possible in the wake of significant cost reductions, combined with lucrative support mechanisms for power generation from RE sources in Germany.

Figure 4.4: LCOE and LCOE scenarios for Solar PV in USD per kWh from 2000 until 2040



Source: (Rystad Energy, 2018)

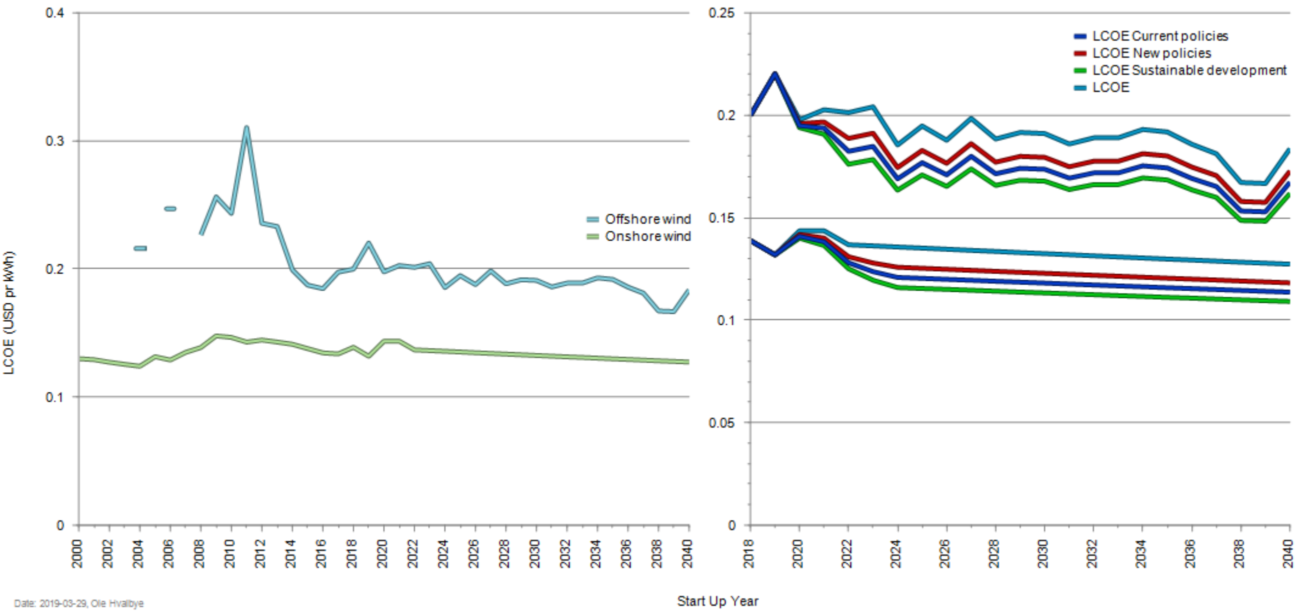
Figure 4.4 illustrates the LCOE for Base Case, and the LCOE Scenarios for the forward-looking CAPEX-reduction from 2020 of 10%, 15% and 20% for RCPS, RNPS, and RSDS respectively for Solar PV in Germany. The illustration to the right shows a snap-shot from 2018 to 2040, where all four cases gradually decrease throughout the time-period. The difference in LCOE of the scenarios in the early time period of the forecast (2018-2021) is explained by a gradual change from a situation with no change in CAPEX, to a situation with three different scenarios of CAPEX reduction which is implemented from 2020. The spike in 2019 of 0.155 USD per kWh for the LCOE Base Case is as a result of forecasted expensive solar PV projects which is under development. The difference between the Base Case (orange) without any CAPEX-reduction and the *sustainable development scenario* (blue) with a reduced CAPEX of 20% is roughly 2 cent (USD) per kWh in 2040. At first, this does not sound like a significant number, however, these cents may be decisive factors when comparing with the LCOE of coal-fired generation. This will be looked into detail in section 4.2.1.1 (solar PV versus coal).

4.1.2.2 Wind

Wind power shows similar characteristics as Solar PV, but the technology is much more mature and has been through the early stage cost reduction decades earlier. Section 3.2.3.3, shows that the installed capacity of onshore wind was the single largest source of capacity for the first time in 2018, contributing with 23.9% of the German power mix. It is also estimated that onshore wind capacity will obtain as much as 43.2% of the market in 2040, followed by coal – 20.4% and gas – 13%[1].

[1] Note that the estimated power mix for Germany going forward is based on the 2018 base case scenario of Rystad Energy research and analysis, which is not including the coal phase-out by 2038 which was included in legislation 26th of January 2019.

Figure 4.5: LCOE and LCOE scenarios for Offshore Wind and Onshore Wind in USD per kWh from 2000 until 2040



Source: (Rystad Energy, 2018)

In the analytical results, and in figure 4.5, wind power in Germany is distinguished between onshore wind and offshore wind. This is contrariwise with figure 4.3, which illustrates an average of onshore and offshore wind. Onshore wind is a more standardized technology, with lower investment costs, deployment costs, and operational costs (see section 3.2.1), whilst offshore wind usually has a higher utilization rate, in the form of operational hours under ideal wind conditions. As initially mentioned are these aspects taken into account when computing LCOE.

The illustration above (figure 4.5) shows that LCOE for onshore wind usually lies somewhere between 5-10 USD dollar cents per kWh lower than offshore wind. In 2018, the average LCOE was 0.14 and 0.20 USD per kWh for onshore and offshore wind respectively. The LCOE for offshore wind does also include a lot of variation going forward. These are explained by forecasted expensive installations, which are illustrated as outliers in the dataset. Similarly, with the illustrations in the sections above, the decrease in cost is caused by the market prospect of the reduced cost of renewables. i.e. looking at the forward-looking real values. The graph on the RHS shows the different levels of CAPEX-reduction scenarios for both technologies. E.g. the difference between the Base Case (light-blue line), and the *sustainable development scenario* (green line, 20% CAPEX reduction) for offshore wind is roughly 2-dollar USD cent per kWh in 2040. The missing datapoints between 2000 and 2008 for offshore wind LCOE can be explained as it was a period with very few commissioned offshore wind projects.

4.1.2.3 Coal

Last, but not least is the LCOE for coal-fired generation a key aspect to evaluate. Contrariwise with the sensitivity analysis and the results in section 4.2 this section include CAPEX in the levelized cost calculations for coal. This is included in order to present an actual overview of coal, whilst, simplifying the levelized cost comparison from a historical point of view. As illustrated in figure 4.3, solar PV, wind and coal lie roughly at the same LCOE level from 2025 until 2032, with coal marginally higher from 2029 going forward (0.13 USD per kWh). As introduced, the CO_2-price concern a significant part of the total operational costs for a coal asset. It is identified throughout this study, to be as much as 25-35% of OPEX in the base case scenario which obtains the current CO_2-price level. Note that this is estimated based on the 2018 base case scenario of Rystad Energy research and analysis.

Figure 4.6 illustrates the development of LCOE and the LCOE scenarios for coal. In 2018, the average coal-fired asset in Germany had an LCOE of 0.135 USD per kWh. The figure on the RHS demonstrates how the LCOE is affected by implementing the three different CO_2-price scenarios from table 4.1 for the year 2020 and 2030. The gradual increase and change over time which are noticeable on the RHS start already from the year 2000. This is as a result of historical LCOE is based on future revenues, which is explained in detail below the figure. As illustrated, the LCOE of coal-fired capacity is quite sensitive to changes in the CO_2-price. E.g. the *sustainable development scenario* (SDS) for 2030 shows that a CO_2-price of \$100 per tonne CO_2 (LCOE: 0.27 USD per kWh) has an LCOE spread of 0.14, 0.11 and 0.10 USD per kWh, compared to the Base Case, CPS, and NPS respectively. The LCOE has increased by as much as 108% compared to the Base Case for 2030.

Figure 4.6: LCOE and LCOE scenarios for Coal in USD per kWh from 2000 until 2031

Source: (Rystad Energy, 2018)

The two illustrations in figure 4.6, are capped at the year 2031. The most optimal case would be to include data until 2040. This was also the intention of the report. But, the time period between 2030 and 2040 contained noisy/misleading data points for the LCOE calculations for coal. This data has been treated as outliers. i.e. excluded from the data-set, consequently, it has been necessary to leave out data between 2030 and 2040 for all the results shown in section 4.2.1. However, due to the point of competitiveness occurring earlier (than expected) in all three results (solar PV vs. coal; onshore wind vs. coal; and offshore wind vs. coal), this is identified as not affecting the results. This is further discussed in section 4.1.4.

It is important to underline that table 4.1 illustrates the same starting points for CO_2-price for CPS, NPS, and SDS of \$18, \$20, and \$20 per tonne respectively in 2020. But, as illustrated in figure 4.6, the LCOE for CPS, NPS and, SDS shows varying LCOE already from the year 2000, whilst increasing to 2018 and going forward. The x-axis in figure 4.6 is the assets start-up year. Therefore, historical LCOE is explained by the fact that LCOE is based on future revenues from an assets start-up year. So, looking at an asset in different scenarios the LCOE should be different. E.g. let’s consider an asset which has a start-up year in 2005 and expected lifetime until 2040. For each scenario, the LCOE will be different. The assets LCOE is depending on three different scenarios (CPS, NPS and, SDS) and the Base Case, and it is assumed that the CO_2-price will only vary from 2020 onwards. Consequently, the LCOE in 2005 (start-up year) will be different for each scenario. This is also the reason for the FLCOE for CPS, NPS, and SDS for coal to start at different values from the year 2014 in figure 4.8, 4.9, and 4.10. The values between 2020 and 2030 are computed by an incremental increase of the CO_2-price. i.e. the CO_2-price for the SDS in 2025 is set to be $60 per tonne (median of 20 and 100).

4.2 Results

This section presents and discusses the results from the sensitivity analysis from section 3.1.2 using the data and scenarios presented in section 4.1.1. The sensitivity analysis is presented in section 4.2.1, illustrating the inflection points between new renewables and existing coal.

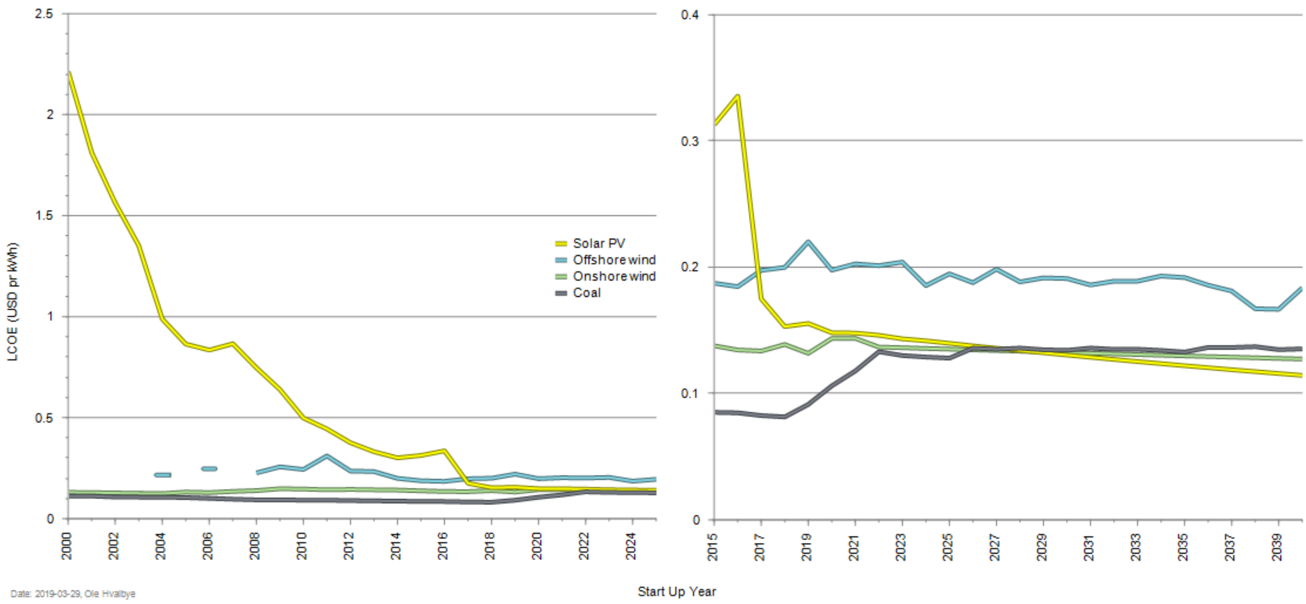
As previously stated, this paper utilizes LCOE to ascertain the point at which it becomes cost completive to switch from a coal asset to a renewable asset, within the context of the German energy market. These crossing-points are denoted as *points of competitiveness*. In the near term, these points indicate that an electricity producing firm would move towards investing in renewables, as the renewable asset has become more cost competitive than the coal asset. Consequently, on a theoretical cost-only basis, the points of competitiveness indicate the conditions under which it would be profitable to scrap coal plants and initiate solar PV and/or onshore wind projects. The presence of these points of competitiveness is relatively near term indicating that utility owners need to factor in CO_2 volatility when evaluating new investments, and indicating the optimal time period when coal should be scrapped and investments should be put towards renewables.

4.2.1 Point of competitiveness

This section illustrates the results of the sensitivity analysis. Separate LCOE and FLCOE estimations for solar, wind and coal are combined in order to evaluate the effect of the different scenarios. In order to distress what is done, and why? A short reminder is as follows. It is analysed under which scenarios new renewable plants are more cost competitive than existing coal plants. The methodology used for estimating this is LCOE calculations with predefined scenarios for both CAPEX-reduction for renewables and CO_2-price increase for coal. New assets are compared to existing assets; therefore, it is chosen to compare operational costs (OPEX) plus capital cost (CAPEX) for new assets, with only the operational cost (OPEX) for existing assets. i.e. the investment cost for coal-fired assets is denoted as a sunk cost. The reason for performing this analysis is to make a simplified estimation for an electricity-producing firm involved in an investment decision of either investing in a new solar or wind project, compared to continuing the operation of an existing coal power plant.

The figure, 4.7 illustrate the standard LCOE for solar PV, onshore wind, and offshore wind, versus FLCOE (excluding CAPEX) for coal in USD per kWh from 2000 until 2030. The figure shows the current/default situation in the database for Germany. i.e. comparing the Base Case Scenario for both renewable LCOE and coal FLCOE. The figure on the LHS shows the LCOE development which is similar to we saw in figure 4.3, but containing separate LCOE estimations for onshore and offshore wind. Also, FLCOE, rather than LCOE for coal is included in the figure below. The forward-looking levelized cost only takes into consideration future costs. For operational plants, this means that only the operational cost, abandonment cost, etc. are included in the FLCOE, while construction cost is treated as sunk. Figure 4.7 shows that the LCOE and the FLCOE are equal to each other from 2022. This is explained by new-build investments which are starting up after 2021 has yet to be made and consequently, future cost equals total cost.

Figure 4.7: LCOE for Solar PV, Offshore Wind and Onshore Wind, versus FLCOE (excluding CAPEX) for Coal in USD per kWh from 2000 until 2030 (left) and from 2010 until 2030 (right)



Source: (Rystad Energy, 2018)

Figure 4.7, illustrates the same analysis on the LHS and on the RHS. The illustration on the RHS shows data from 2015 until 2040. This figure shows the points of competitiveness between the different energy sources: as initially discussed, solar PV has experienced a levelized cost decrease of 93% since the year 2000, from LCOE levels of roughly 2.2 USD per kWh, which is very high compared to onshore wind, offshore wind, and coal for the same year, which is roughly around 0.1 USD per kWh. In 2017, the LCOE for solar PV crossed the LCOE for offshore wind in Germany at 0.195 USD per kWh, and so became a cheaper alternative in terms of levelized cost in the following years. Additionally, onshore wind is assumed to have a lower LCOE than solar PV in Germany until 2029 at 0.13 USD per kWh. If the capital expenditure is neglected, coal-fired power generation is assumed to be the alternative with the lowest LCOE until 2026 (point of competitiveness for onshore wind), where the LCOE is 0.135 USD per kWh. Note that this is the real value which does not take inflation into consideration going forward.

Also, note that figure 4.7, is an estimation from the database which concerns the Base Case Scenario for both renewable LCOE and coal FLCOE. i.e. evaluating the current situation in Germany. The following three sections will look deeper into how the cost curves are shifted when implementing the CAPEX-reduction scenarios and the CO_2-price scenarios.

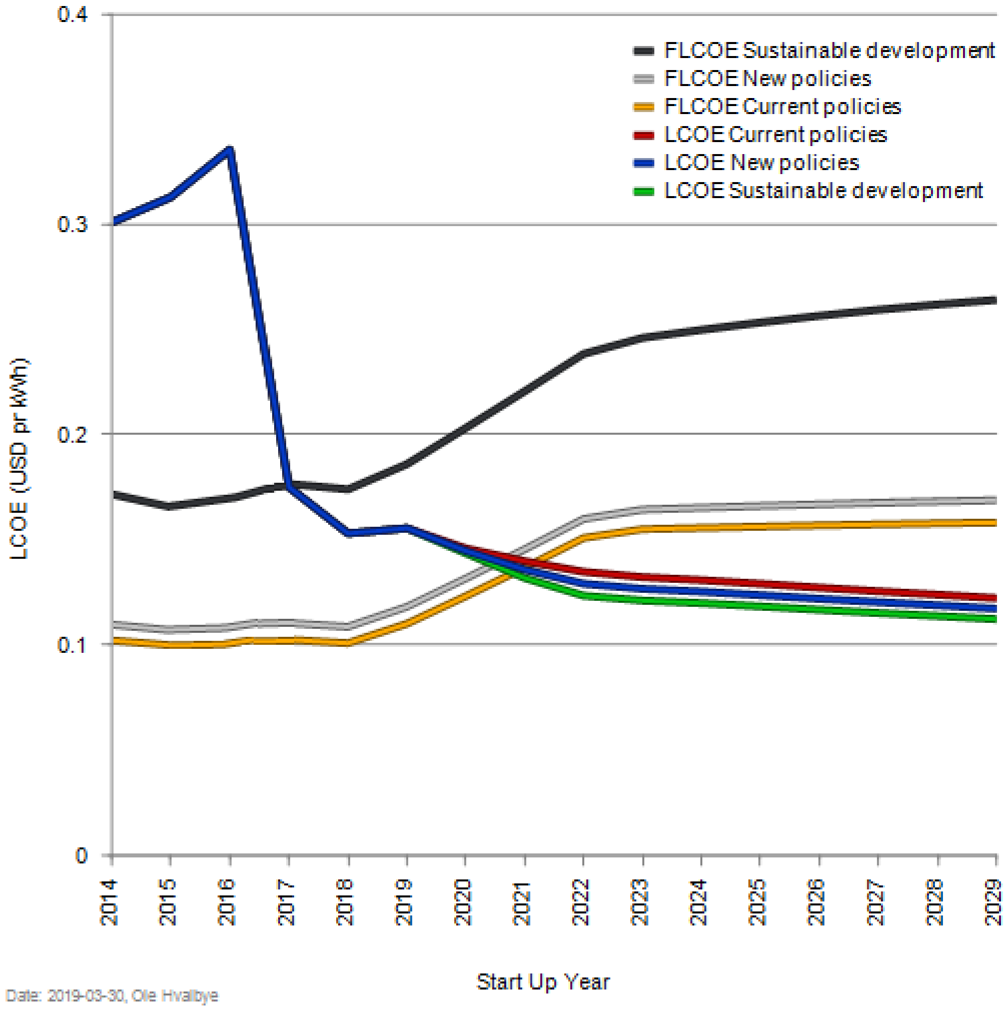
The following three sub-sections include one illustration each covering both the renewable scenarios and the coal scenarios. Each section includes either solar PV, onshore wind or offshore wind versus coal. A short reminder of the scenarios and the naming used in the illustrations are as follows: LCOE denotes scenarios for renewables, while FLCOE indicates scenarios for coal. LCOE RCPS, LCOE RNPS, and LCOE RSDS are equal to 10, 15 and 20% CAPEX-reduction respectively; FLCOE CPS, FLCOE NPS, and FLCOE SDS are equal to predefined CO_2-prices for different periods in time. The CO_2-prices are explained in detail in section 4.1.1, under table 4.1. The analytical results illustrated in figure 4.8, 4.9, and 4.10 covers the period, 2014 to 2029, as this is sufficient in order to demonstrate the relevant points of competitiveness.

4.2.1.1 Solar PV versus Coal

The first analysis evaluates all scenarios of CAPEX-reduction for solar PV versus all scenarios for CO_2-price increase for coal. Illustrating all scenarios simultaneously allows for a simpler comparison while reducing the need for many figures.

Figure 4.8 compares the levelized cost of solar PV and the forward-looking levelized cost of coal. First of all, it is important to underline that CPS's CO_2-price of 40, NPS's CO_2-price of 50, and SDS's CO_2-price of \$140 per tonne CO_2 for the year 2040 are all acknowledged to be far outside the range of illustrative points of competitiveness. Therefore, these are left out of the illustrations. Secondly, it is important to emphasise that the CAPEX-reduction scenarios for renewables commences from 2020 and onwards, whilst the CO_2-price for coal is set to follow the historical European Union Allowance (EUA) (section 3.2.3.2, figure 3.8) prices from 2014 to 2019, and IEA's CO_2-price assumptions in table 4.1 from 2020 and onwards. IEA's CO_2-price assumptions are set to be specific values for specific years, the intermediate CO_2-price between 2020 and 2030 is set to be linearly increasing between the data points.

Figure 4.8: LCOE Scenarios (RCPS, RNPS and RSDS) for Solar PV, versus FLCOE Scenarios (CPS, NPS and SDS) for Coal in USD per kWh from 2014 until 2029



Source: (Rystad Energy, 2018)

Figure 4.8 enables comparison and verification of points of competitiveness between all scenarios for both LCOE for renewables and FLCOE for coal. Firstly, the comparison between the *current policies scenarios* for both LCOE and FLCOE is discussed. i.e. 10% CAPEX reduction for solar PV, and gradually increasing CO_2-price from \$18 to \$30 per tonne CO_2 for coal between 2020 and 2030. This is illustrated through the point of competitiveness between the red line for LCOE and the orange line for FLCOE. This cost comparison indicates that in mid-year **2021** (June), at a levelized cost of **0.135 USD per kWh** there exist a point of competitiveness. Thus, it can be said that after 2021, an investment decision based on cost alone would favour a new solar PV plant rather than continue operating an existing coal plant. Note that this point of competitiveness applies to the existing CO_2-price policy regime in Germany, and an estimated CAPEX reduction of 10% for solar PV.

Secondly, LCOE and FLCOE for the *new policies scenarios* are compared. i.e. 15% CAPEX reduction for solar PV, and a CO_2-price from \$20 to \$37 per tonne CO_2 for coal between 2020 and 2030. This comparison is illustrated as the point of competitiveness between the blue and the grey line. Compared to the current policies, there is a small change, with a point of competitiveness at **0.14 USD per kWh** in mid-year **2020**, indicating an estimated change in the investment decision. This shows that the small change (from current to new policies) in CAPEX and CO_2-price can shift the cost advantage of solar PV a full year ahead but at a higher levelized cost.

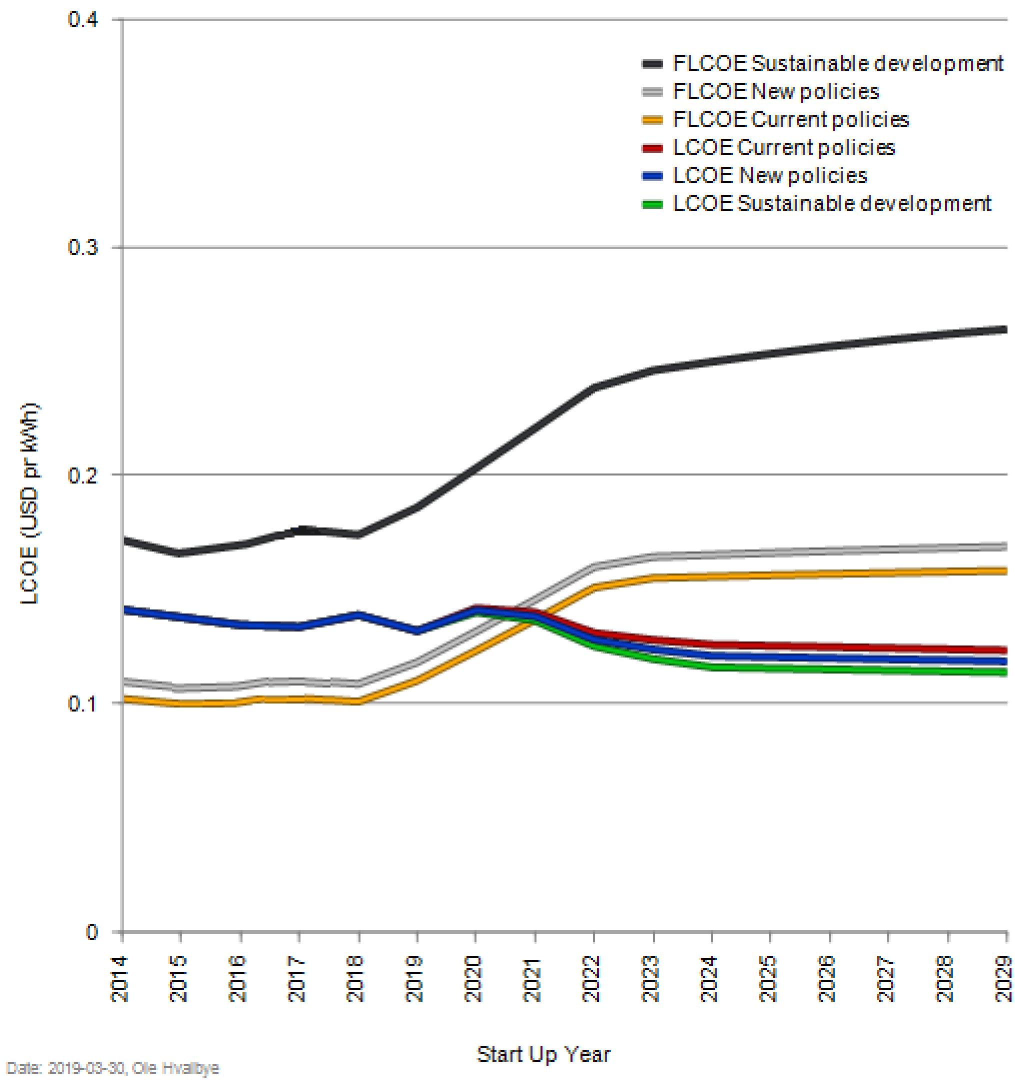
Lastly, the most aggressive scenario is evaluated. The *sustainable development scenario* includes 20% CAPEX reduction for solar PV and \$20 to \$100 per tonne CO_2 as the CO_2-price for coal between 2020 and 2030. This point of competitiveness is illustrated through the intersection between the blue line for LCOE and the black line for FLCOE. For this scenario, there is a significant change compared to the *current policies scenario*s and the *new policies scenarios*, with a point of competitiveness at **0.175 USD per kWh**, already in **2017**.

Note that the last point of competitiveness (within the SDS) is slightly misleading as it occurs three years before the CAPEX reductions which are included for renewable LCOE. The point of competitiveness dating two years back in time is a result of the LCOE characteristics explained in detail in section 4.1.2.3 (Coal). i.e. the historical LCOE values illustrated is determined by assets start-up year. The LCOE is a calculation of future revenues depending on the start-up year of the asset. Therefore, solar PV and coal-fired assets which start-up in 2017 will illustrate an LCOE which is dependent on the future prospects of CAPEX reductions and CO_2-price for the scenario.

4.2.1.2 Onshore Wind versus Coal

The second analysis evaluates all scenarios of CAPEX-reduction for onshore wind versus all scenarios for CO_2-price increase for coal. Historically, onshore wind is acknowledged to be the most mature and cost-efficient renewable energy technology in Germany.

Figure 4.9: LCOE Scenarios (CP, NP and SD) for Onshore Wind, versus FLCOE Scenarios (CP, NP and SD) for Coal in USD per kWh from 2014 until 2029



Source: (Rystad Energy, 2018)

Figure 4.9 does also illustrate and verify the points of competitiveness between all scenarios for LCOE and FLCOE. The *current policies scenarios* for onshore wind (red) and coal (orange) obtains similar results as for the *current policies scenarios* for solar PV, with an illustrated point of competitiveness in mid-year **2021** at **0.14 USD per kWh**. i.e. after 2021, new onshore wind installations have a lower levelized cost than operational coal-fired assets in Germany. It is worth mentioning that the base case for onshore wind is estimated to obtain lower LCOE than coal, but higher LCOE than solar PV between 2029 and 2040, this is illustrated in figure 4.7. As illustrated in figure 4.9, all scenarios are assumed to obtain roughly 0.13 USD per kWh in 2022.

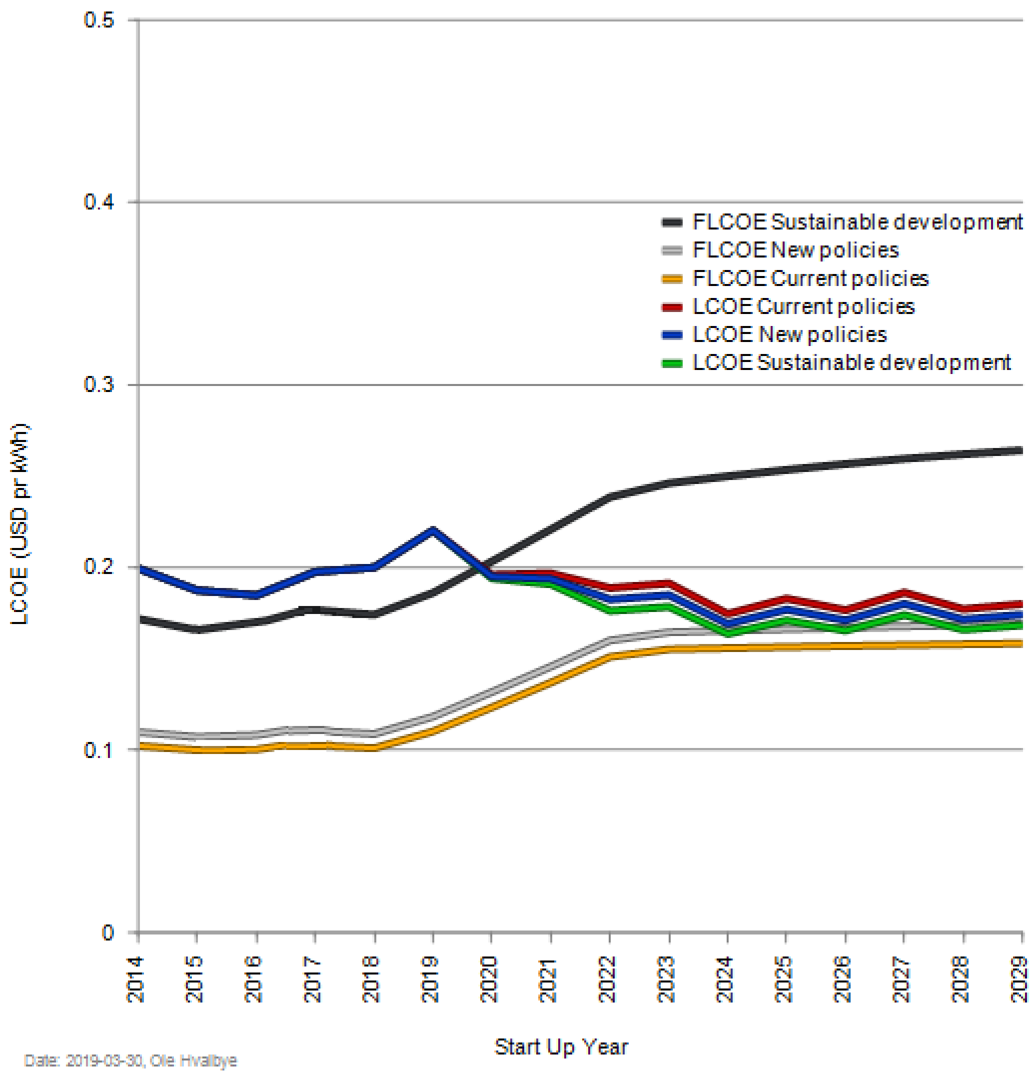
The *new policies scenarios* illustrate a point of competitiveness between LCOE (blue) and FLCOE (grey) at **0.138 USD per kWh** in mid-year **2020**, which is marginally below the LCOE for solar PV for the same year.

The *sustainable development scenario* for onshore wind in Germany illustrates an interesting case. As illustrated in figure 4.7, the historical values demonstrate low LCOE for both onshore wind and coal dating back to before the year 2000. From the same figure, it is also noticeable that onshore wind and thermal coal has shown to have a similar level of LCOE in the last eighteen years, while this trend is forecasted to continue until 2040. Therefore, the *sustainable development scenario* for onshore wind LCOE (green), do not demonstrate to be higher at any time than the *sustainable development scenario* for FLOCE (black) for coal in the time period considered in the figure.

4.2.1.3 Offshore Wind versus Coal

The third and last analysis evaluates all scenarios of CAPEX-reduction for offshore wind versus all scenarios for CO_2-price increase for coal. Offshore wind is identified as obtaining relatively high levelized cost, both historically, and present. Therefore, the existing point of competitiveness is shifted to the right (later in time).

Figure 4.10: LCOE Scenarios (CP, NP and SD) for Offshore Wind, versus FLCOE Scenarios (CP, NP and SD) for Coal in USD per kWh from 2014 until 2029



Source: (Rystad Energy, 2018)

Figure 4.10 verifies the comparison between all scenarios for LCOE and all scenarios for FLCOE, for offshore wind and coal respectively. The comparison between coal, which is historically a very mature source of energy in Germany, and offshore wind, which had its first commercial-scale project in 2009, illustrates an interesting case: The *current policies scenarios* for offshore wind (red) and for coal (orange) as calculated show no intersection any time in the forecast period (2014-2030). Indicating a continuous operation of existing coal-fired power plants rather than developing new offshore wind projects.

Even though it is difficult to interpret from figure 4.10, the *new policies scenarios* illustrated in blue (LCOE) and grey (FLCOE) demonstrates to intersect in **2028** at **0.168 USD per kWh**. i.e. an investment decision, primarily based on cost, would favour continuing operating existing coal-fired power plants until 2028 while developing new offshore wind projects after 2028.

Lastly, the *sustainable development scenario* for offshore wind (green/blue) and coal (black) verifies a point of competitiveness in **2020** at **0.195 USD per kWh**, which is significantly high compared to the *sustainable development scenario* for solar PV, and all other scenarios for both solar PV and onshore wind.

4.2.2 Summarising

The following table (table 4.2), summarizes the points of competitiveness illustrated and discussed in section 4.2.1. As expected, not all scenarios for all technologies are shown to intersect. However, all three comparisons illustrate similar output: reducing the CAPEX for renewables (solar PV, onshore wind, or offshore wind) and increasing the CO_2-price for coal, results in shifting the point of competitiveness of LCOE's to the left. i.e. making the investment decision, on the theoretical level favour renewable energy investment at an earlier stage. Consequently, increasing the cost competitiveness of renewables relative to coal. A shift to the left does not necessarily mean a lower LCOE. Particularly, the *sustainable development scenario* for coal illustrates such a high level of LCOE that it is intersecting with the historical LCOE of solar PV (with base case CAPEX), not crossing any onshore wind LCOE, and being one out of two intersecting scenarios for offshore wind between 2014 and 2030. The intention was to find as many points of competitiveness as possible in the forecast period and to look deeper into these.

Table 4.2: Summary of the point of competitiveness (USD per kWh) per technology and scenario.
* Point of competitiveness btw RSDS and SDS for solar PV v. coal occurred before 2020. i.e. outside the RSDS scenario range

Point of competitiveness per technology and scenario			
Technology	Scenario	Year	LCOE value (USD per kWh)
Solar PV versus coal	Current policies	2021	0.135
	New polices	2020	0.140
	Sustainable development	2017*	0.175*
Onshore wind versus coal	Current policies	2021	0.140
	New polices	2020	0.138
	Sustainable development	-	-
Offshore wind versus coal	Current policies	-	-
	New polices	2028	0.168
	Sustainable development	2020	0.195

From table 4.2 it is noticeable that the LCOE points of competitiveness range vary from 0.135 to 0.195 USD per kWh. The points of competitiveness illustrate a starting point (year) with an LCOE value from where the renewables are assumed to be a cheaper alternative in line with the implemented scenarios. Going-forward the LCOE for the renewable sources are assumed to decrease (see figure 4.7). From the LCOE summary (table 2.4) in section 2.2.2.4 in the literature review, it is shown that the LCOE from various sources is lower for all technologies in all cases. VGB (2015) illustrates relatively high LCOE values for solar PV, offshore wind, and super-critical coal, all at roughly +/- 0.12 USD per kWh, while low values for onshore wind at 0.08 USD per kWh, and lignite super-critical at 0.065 USD per kWh. LCOE estimates from IRENA (2018) are similar, except that solar PV is 0.095 USD per kWh and onshore wind is lower at 0.06 USD per kWh, while offshore wind is significantly higher at 0.13 USD per kWh. DEA (2015) has even lower LCOE's for the renewable sources, while higher for coal up to 0.16 USD per kWh incl. system and externalities cost. Additional to the literature for LCOE estimations used in section 2.2.2.4, Fraunhofer ISE, Kost et al. (2018) is also used in order to illustrate levelized cost estimations, whilst comparing it with the results from section 4.2.1. Kost et al. (2018) identify the following energy source specific LCOE calculations: solar PV systems are set to have an LCOE range of 0.042-0.13 USD per kWh; onshore wind has a range of 0.045-0.092 USD per kWh; while offshore wind has a range of 0.084-0.15 USD per kWh; and lastly, 0.051-0.089 USD per kWh and 0.070-0.11 USD per kWh is identified for brown coal (lignite) and hard coal (anthracite) respectively. The LCOE estimations from Kost et al. (2018), demonstrates similar values as for the calculated results and the literature from section 2.2.2.4 for solar PV, onshore and offshore wind. However, the study finds a lower range of LCOE for coal, than what is identified in this study (~0.13 USD per kWh for the base case). The difference for the coal LCOE is explained by the input variables. The range of costs is mainly associated with the large variation in full load hours, which is explained further in section 2.2.2.4. Since the full load hours result from the variable marginal cost of each asset, they are dependent on the forecasted values of fuel price, CO_2-price, development of renewable electricity feed-in and composition of the power plant complex (Kost et al., 2018).

This demonstrates that different sources and calculations arrive at quite different levelized cost depending on the input variables. The micro-to-macro composition of the PowerCube results in a high degree of granularity suitable for LCOE calculations, including production and asset-based cost break-down, which has been presented in detail in section 3.2.1 (variable definitions).

Another reason for the differences compared to the computed LCOE's from section 4.2.1, are that the LCOE estimations from section 2.2.2 are based on theoretical estimations per technology. E.g. each source use predefined full load hours per technology (see table 2.2, and 2.3), while the computations from PowerCube in section 4.2.1 are based on actual scouted production and forecasted production per asset.

As illustrated in section 4.2.1, the CAPEX-reduction have a surprisingly small effect on the levelized cost calculations for solar PV, onshore and offshore wind. Taking solar PV as an example, it is shown in figure 4.4 that the difference between the scenarios is quite small. E.g. for the year 2022, the LCOE for the base case, RCPS, RNPS, and RSDS is 0.148, 0.135, 0.129, and 0.123 USD per kWh respectively. On the other hand, the OPEX for coal-fired assets for the same year (2022) is significantly sensitive to varying CO_2-price. From figure 4.6, it is shown the following LCOE values: 0.134, 0.156, 0.164, and 0.242 USD per kWh, for the base case, CPS, NPS, and SDS respectively. The difference between 0.242 USD per kWh for SDS and 0.134 USD per kWh for the base case is as much as 0.108 USD per kWh, which is arguably a very high spread.

Regardless of the sensitivity of the two variables, the scenarios are based on likely future estimations from Rystad Energy research and analysis and IEA. The CAPEX-reductions of 10% (RCPS), 15% (RNPS), and 20% (RSDS) are based on Rystad Energy's forecast for a situation with a low, medium, and high reduction in CAPEX until 2040, which is in line with IEA's forecast. The CO_2-price concerning thermal coal-fired assets is collected from IEA's World Energy Outlook (WEO). The *current policies scenario* for the CO_2-price is developed on the basis of IEA's low case, which considers the impact of those policies and measures that are firmly in place in legislation as of mid-2018. Consequently, having the aim of providing an estimation of where momentum from current/existing policies might lead the power industry, given a situation with no other/new incentives from policymakers. The *new policies scenario* for the CO_2-price aims to provide an assessment of where new policy ambitious seems likely to lead the power sector. The NPS includes not only the policies and measures that are already put in place but also the likely effect of announced policies. New policies do also include the Nationally Determined Contributions made for the Paris Agreement. Lastly, the SDS sketches an integrated approach necessary to achieve internationally agreed goals on climate change, air quality and access to electricity. i.e. the scenario includes where the industry needs to be to reach the objectives of the Paris Agreement.

Based on the theory behind IEA's policies scenarios, it is reasonable to assume that either the *current policies scenario* or the *new policies scenario* is the most likely scenarios going forward. However, one should not underestimate the likeliness of implementation of newer more aggressive climate policies (SDS) for the future given the current situation in the EU, and especially Germany. This statement can be underpinned by the current decision taken by the German coal commission, which has decided to phase out all coal-fired generation in Germany before 2038.

4.2.2.1 Germany Carbon Lock-in

An overview of the current energy situation in Germany is summarized and discussed before it is evaluated in line with the results from section 4.2.1 in the conclusion. The political policies, historical events, and milestones of the Energiewende presented in section 2.1.2, demonstrate how central policies, often in the wake of particular events, are for the market structure and developments within the energy mix. For Germany, the Energiewende and the Nuclear phase-out, have both been central for shaping the current electricity system.

For the public and international onlookers, the Energiewende gained significant attention in 2010-2011 when the energy concept was initiated, which introduced plans to significantly increase the share of the country's electricity production from RE sources, whilst cutting the country's overall carbon emissions to 40% below 1990 levels by 2020, and on the same time (in 2011) initiating Nuclear phase-out #2, which announced a widespread national nuclear phase-out by 2022.

Since the beginning, it has existed a lot of scepticism around Germany's approach in order to cope with damaging CO_2 emissions from the power sector. As presented in section 2.1.2, Energiewende has experienced both progress and drawbacks, and there is no doubt that it still requires a lot of effort in order to meet the targets presented in section 2.1.2.4.

However, independent of support and critics, the success and drawbacks of Energiewende can be measured by different results and outcomes. From section 2.1.2.2, the four key drivers of Energiewende was presented, namely: environmental sustainability, energy imports reduction, technological development, and economic growth. Arguably, the most relevant aspects being raised by the public is the CO_2 emissions targets, and economic growth.

As presented in section 2.1.2.1, the Energiewende monitoring report, FMEAE (2015), by BMWI estimated that the 2020 emission reduction goal was likely to be substantially far-off what was originally intended. Additionally, BMWI's 6th and newest edition from June 2018, BMWI (2018) is evaluating the 2030 targets. Unfortunately, the monitoring report estimates rather bad news, and states “with the current dynamics, reaching the 2030 target is likewise not possible” (BMWI, 2018). The authors highlight that the emissions would have to be reduced three times as much between 2017 and 2030 as they were between 2000 and 2017, consequently underpin a very unlikely event (CEW, 2018). BMWI (2018) also demonstrates that so far has the Energiewende failed to reduce energy consumption, increasing energy efficiency, and expand/optimise the power grid. On the other hand, the initiation of Energiewende has caused reductions in energy dependency, energy import costs and welfare loss. As well as promoting job creation, and technological innovations (GABI, 2014). Even though Germany take good advantage of these positive repercussions, it is acknowledged that the sustainability goal is even tougher to reach now than what it was a few years ago.

Figure 3.4 in section 3.2.2.3 demonstrates that, for the first time in 2018, the installed capacity was dominated by onshore wind, having 23.9% (56.1 GW out of a total 234.8 GW), whilst coal accounted for 23.4% of capacity. Furthermore, does the Rystad Energy PowerCube database assume onshore wind to dominate the capacity in 2040 with 43.2% of the market versus 20.4% from coal. However, this only demonstrates a small part of the situation. Even though the onshore wind is estimated to lead in terms of installed capacity from 2018 and onwards, the German power production data demonstrate a different situation. In 2018, onshore wind accounted for 13.3% (85.2 GWh) versus 40% (257.4 GWh) from coal-fired electricity production. Additionally, 257.4 GWh from coal is 32.6 GWh more than all the renewable energy sources combined, and coal is assumed to be the dominating source of power production until 2035.

Coal-fired dominance is related to Germany’s traditions and role as a major coal mining nation. As demonstrated in section 2.1.2.3, the energy concept from 2010 underlines the reduction of energy imports to be a key factor for the Energiewende. At the time of writing Germany is closing its last Anthracite mine, named Prosper-Haniel, and has since 2017 reduced anthracite coal capacity with 1.2 GW. However, Germany is still the biggest producer of lignite (brown coal) in the world, extracting as much as 172 million tonnes in 2016, where approximately 90% of total lignite output is used for domestic power and district heat generation. Additionally, roughly 70,000 competitive jobs are secured by the lignite mining and lignite-based power generation industry (DEBRIV, 2016).

Even with hundreds of billions of euros invested in RE installations, Germany continues to be significantly dependent on power production from lignite-fired coal plants, the most emission-intensive source of energy. In September 2018, RWE's Hambach mine was additionally expanded and has been granted permission to be operative for exploitation until 2040 (FT, 2018). Germany's dependence on lignite is acknowledged to be the main reason why the country is struggling to lower its carbon dioxide emissions. However, the government announced in January 2019 a target-year for phasing out all coal-fired power stations by 2038. Nevertheless, it is important to emphasise that the coal phase-out and its measured steps are not included in the analytical results in this report but is an important aspect to consider for further research.

There is little doubt that the German energy system has, and currently is experiencing an effect of carbon lock-in. The electricity market is more or less fully dependent on the carbon emission-intensive power production from coal-fired power plants. Also, the dependency of coal has, and will, grow stronger in the wake of a complete nuclear phase-out by 2022, which is expected to be on time as presented in section 3.2.2.3.

However, the results from section 4.2.1 show that, on a theoretical level, coal won't be competitive until after mid-year 2021 within the current/existing policy scenario (CPS). This means a 10% CAPEX reduction for solar PV and onshore wind, with the point of competitiveness at 0.135 and 0.138 USD per kWh respectively. These findings indicate that there is no lock-in because it would be profitable to scrap coal plants and initiate solar PV and/or onshore wind projects. Nevertheless, these theoretical points of competitiveness are too simple as they leave out many considerations. This will be elaborated on further in the section below (Remarks) and in limitations in section 5.2.

4.2.2.2 Remarks

Section 4.2.2.2, and 4.2.2.3 provides a quick overview of the remarks and the shortcomings worth notifying.

First of all, the reliability of data needs to be questioned. As the PowerCube is a non-commercialised product in the pilot phase, some data points may not correspond exactly with the actual situation. But, a substantial part of the project has been to quality control the database, as well as continuing the process of database development, and the cubes have shown very promising data concerning plant-level capacities, production, and economics, which has shown to be suitable for a master thesis project.

In order to evaluate how an investment decision is made in power generation, it is optimal to include the historical, and forecasted electricity price. However, this project has focused only on power generation cost.

It is also important to emphasize that, even though it exists a push for renewables due to declining costs, it exists a physical maximum of how much of the installed capacity that should come from intermittent energy sources. Security of supply is highly valued from non-intermittent sources. In the future, storage technology, most likely in the form of batteries could supply power generation sectors with reliable electricity and change the physical maximum of renewable capacity. The aspect of storage is not included in this report.

Renewable energy, in the form of solar PV and wind, is set to produce whenever the sun shines or the wind blows. This is usually the case even at times with low power demand. Consequently, the electricity price tends to drop significantly at periods with much supply and low demand. It exists cases in Germany and Denmark with oversupply, resulting in negative electricity prices. i.e. consumers are paid to use electricity. Therefore, it is questioned whether it is a good thing to commission more renewable capacity in already saturated power markets. Fully working long-term storage capabilities could change this in the future.

Also, a few months before the submission of this report (26th of January), the German coal commission has come to an agreement to phase-out all coal-fired generation in Germany in 2038. This is not included in this report. However, this would only cause small changes to some illustrations of forecasted installed capacity, etc. But, it would have no effect on the calculations from chapter 4. On the contrary, the set phase-out year for coal underlines the importance of the theory raised in this report.

It is important to emphasise that all the results. i.e. the economic values presented in chapter 4, such as OPEX and CAPEX in MUSD, and LCOE in USD per kWh are illustrated in real values and not nominal values. i.e. the forecasted costs do not take inflation into consideration. Consequently, illustrating the levelized cost as a decreasing factor for all energy sources for the future, which is in line with the assumed market prospects. i.e. LCOE is theoretically assumed to decline or stay relatively flat depending on the energy source.

4.2.2.3 Shortcomings

The LCOE is calculated based on the actual scouted cost and the actual scouted production, as well as the forecasted costs and the forecasted production on the asset level. Therefore, the levelized costs are excluding any form for support mechanisms, such as subsidies.

It is important to emphasise that comparing energy sources by LCOE and using this as an approach to determine investment decisions going forward leaves out many considerations. This report only compares the cost competitiveness measured by LCOE which is explained in detail in section 3.1.2.1. Fulfilling the cost competitive condition in Eq. (3.5) demonstrates an important point of inflection on the theoretical level within which utility-owners/investors will scrap the existing coal plant. However, the exact future costs are not known, consequently making the decision whether to scrap an existing coal plant less clear.

The limitation of the LCOE perspective is worthy of particular elaboration. Borenstein (2012) argue that LCOE depends heavily on technological factors and economic variables. The economic variables are usually the reason for the large inconsistencies between LCOE estimations. These include inflation rate, interest rate, load hours, and operational expenses such as fuel. The technological factors closely interact with the economic variables. E.g. optimal usage affects the load hours, while load hours change the marginal cost of production and so on. This, together with the fact that power generation plants are heterogeneous in location results in various LCOE calculations even for plants with similar technology (Borenstein, 2012). Power generation sources which depend on the weather to operate, such as solar PV and wind is the least dispatchable technologies. Consequently, also the most challenging for LCOE calculations. i.e. power output from intermittent sources should be evaluated in terms of operating hours, which is not controlled by the plant operator. Hence, being difficult to forecast for LCOE estimations.

The report is analysing cost comparison between renewables and coal, whilst discussing the point of competitiveness for when it is more lucrative (in terms of cost) to build a new renewable plant instead of continuing operating an existing coal plant. However, it is important to question whether or not RE is an ideal substitute for coal. Therefore, this report assumed that renewables are a relevant substitute for coal. i.e. solar PV, wind and coal are assumed to be homogeneous energy sources with all the same characteristics neglecting renewables intermittent nature.

5 Conclusions

This analysis has successfully determined the multiple scenarios where new renewable plants are more cost competitive than existing coal plants in Germany. LCOE calculations have been used as the primary methodological mechanism to determine this, by imposing CAPEX-reductions for renewable assets and CO_2-price increases for coal assets. The LCOE methodology allowed for the comparison of n*ew* assets to *existing* assets by allowing for a comparison of *operational costs* (OPEX) plus *capital cost* (CAPEX) for new assets, and only the *operational cost* (OPEX) for existing assets (the investment cost for coal-fired assets is understood within this analysis as a *sunk cost).*

The market conditions under which new renewable plants are equally or more cost competitive than existing coal plants have been derived by calculating yearly asset-specific LCOE, which is weighted averages based on production. The LCOE's for renewables and coal have been compared within different scenarios, utilizing data modeling from Rystad Energy and IEA (2015b) World Energy Outlook. The yearly scenario-based LCOE comparisons are shown through points of competitiveness from section 4.2.1, which illustrate the final results. The findings of this analysis answer the primary hypothesis:

> What points in time and what are the exact LCOE values where it becomes cost competitiveness to switch from a coal asset to a renewable asset within the context of the German electricity market?

The results illustrate that cost competitiveness between new renewables (solar PV, onshore wind, and offshore wind) and coal in the German electricity market does cross at multiple points in the near term.

The cost competitiveness of solar PV will surpass coal in 2021 at 0.135 USD per kWh, and in 2020 at 0.140 USD per kWh, within the political landscape of the current policy environment (*current policies scenario*), and the forecasted likely policy scenario (*new policies scenario*), respectively. This implies that after 2021, a theoretical investment decision should benefit new solar PV installations rather than favoring the continuance of existing coal plants. In fact, within the theoretical *sustainable development scenario* for coal with the high case of CO_2-price, coal assets were already less cost competitive than the *base case* for solar PV at 0.175 USD per kWh in 2017.

An analysis of onshore wind versus coal assets reveals similar characteristics within the *current policies scenario* and the *new policies scenario*, the cost competitiveness of which intersects with coal in 2021 at 0.140 USD per kWh, and in 2020 at 0.138 USD per kWh respectively. Historically, onshore wind has been among the cheapest sources of energy, therefore the *sustainable development scenario* for coal does not intersect the historical low LCOE of onshore wind, as it is already more cost competitive than coal. This indicates that it has been cheaper to install new onshore wind capacity since 2014, rather than continue operating a coal plant with the high case CO_2-price.

The more expensive alternative, offshore wind, paints a different picture when compared to coal. Within the *current policies scenario*, coal and offshore wind do not intersect any time in the forecast period (2014-2030). Consequently, even with increasing CO_2-prices (for CPS), new installations in offshore wind are more expensive than the continued operation of existing coal plants within the forecast period. The *new policies scenario* and *sustainable development scenario* illustrate points of competitiveness in 2028 and 2020 at 0.168 and 0.195 USD per kWh respectively. The 2028 point of competitiveness is a very likely outcome and requires a 15% CAPEX reduction for offshore wind and a CO_2-price of $33.60 per tonne CO_2 (assuming a linear increase 2020-2030). Conversely, the 2020 point of competitiveness includes a 20% CAPEX reduction for offshore wind in only 1 year, which is less likely in an electricity market without sufficient support mechanisms for RE generation.

The findings in section 4.1.1 (scenarios), and section 4.2.1 (points of competitiveness) also answer the sub-questions established in the introduction and evaluate how sensitive the LCOE of renewables and the LCOE of coal are to a decrease in CAPEX, and an increase in CO_2-price respectively. These questions also assess how CAPEX and CO_2-price variations will affect the cost competitiveness of the technologies. It is shown that CAPEX-reduction has a surprisingly small effect on the levelized cost calculations for solar PV, onshore and offshore wind. This is discussed in detail in section 4.2.2, under table 4.2. On the other hand, the OPEX for coal-fired assets is significantly sensitive to varying CO_2-price. This is also explained in detail under table 4.2. The *sustainable development scenario* (SDS) for coal, which intersects with the base case for solar PV, is a good example of how sensitive coal-fired generation is to an increase in CO_2-price.

5.1 Limitations

5.1.1 LCOE

First of all, the methodology of using LCOE to determine the competitiveness of different technologies is not optimal as it leaves out many important considerations. E.g. assets future operational and economic variables, such as load hours and fuel cost (coal), directly dictates costs, and are difficult to anticipate. Additionally, LCOE's dependency on these variables is the main reason for the large inconsistencies between different sources which include different assumptions underlining their calculations. In other words, it is difficult to point out one specific methodology for computing LCOEs, which makes it challenging to compare different calculations from different sources. The challenges around intermittency for renewables does also amplify the uncertainty for the LCOE estimations. Levelized cost estimations do also quantify the competitiveness of RE and coal only based on costs. However, it is important to question whether or not renewables are an ideal substitute for coal. Therefore, the findings in this report are based on the assumption that power production is homogeneous, providing similar characteristics for all technologies.

An LCOE analysis should also preferably include the additional systems cost for renewables, such as necessary grid updates and storage capabilities for it to be comparable with the dispatchable technologies, such as coal. However, LCOE calculations for coal-fired generation should also optimally include the substantial cost of climate externalities. These two aspects are worth considering for further research covering cost comparisons between renewable and conventional power generation.

What you can sell your electricity for is an important aspect when evaluating RE's competitiveness and investments in new energy capacity. Electricity generation from renewables has low operational expenditures, consequently allowing for highly competitive electricity prices. However, policies which promote the security of supply from dispatchable technologies could in some cases be awarded a fixed competitive electricity price over a long period. Consequently, hedging coal plants against low and volatile electricity prices in electricity markets with a high share of intermittent generation. This is also something that is not taken into consideration in this report. i.e. the findings assume policy-free market conditions for both RE and conventional generation.

5.1.2 Methodology

The aim is to compare new renewable projects with existing coal plants. In order to do this, the methodology has been to compare the weighted average LCOE of renewable to the weighted average LCOE of existing coal plants excluding CAPEX. Both LCOE estimations are based on the start-up year of different assets. In principle, projects which have been installed in e.g. 2010, enter the calculation of average LCOEs of projects to be installed in 2025. Under the assumption that the most recent installations, e.g. 2016-2018, give the best estimate of future cost, the incorporation of older projects is acknowledged as a limitation which is worth considering for further research. However, figure 4.3 in section 4.1.2 (LCOE Comparison) shows flat-line cost evolution for coal (CAPEX & OPEX) and wind (average value between onshore and offshore) from the year 2000 until 2018. i.e. indication no historically great cost development of coal and wind. Thus, underlining the basis for using averages. The cost of solar PV (figure 4.3) illustrates a different situation - the LCOE has decreased from roughly 2.2 USD per kWh in 2000 until

0.15 USD per kWh in 2018 - an LCOE decrease of 93% in 18 years, which indicates that the use of the most recent installations (2016-2018) would have been providing the best estimate of future costs.

Another limitation or remark which is worth considering is the one-time cost reduction applied for the CAPEX-reduction scenarios for renewables. Alternatively, a methodology including learning curves could be more realistic. A learning curve relates the LCOE to cumulative installed capacity. Fitting a regression line to data gives a learning parameter, with which a learning rate can be computed. The closest substitute and a good alternative to working with learning curves are the assumptions of annual percentage decline in CAPEX. It is worth emphasising that the use of learning curves or assuming annual percentage declines could improve the credibility of the results. i.e. either using historical data to calculate a learning curve for the technology (represented in cost compression) or applying a linear decrease as it would be more credible. However, since it is highly uncertain when the cost of renewables will decline and although a linear reduction could have been used - it was decided that by applying a direct impact of the reduction in the coming year (2020) for different scenarios the cost reductions impact can be easily illustrated compared to linear reduction. Additionally, a one-time cost reduction is acknowledged to be the simplest method for illustrating a direct impact, limiting the need for complex models, which is difficult to explain and take the focus away from the cost competitive analysis.

Lastly, the use of averages does not exploit the opportunities provided by the plant-level database. Optimally, a quantification of what fractions of coal-fired power production in Germany which becomes uncompetitive when could be calculated. This analysis is possible with the database, but had to be programmed into the PowerCube Pilot, and has therefore been neglected due to time constraints. However, this analysis is worth considering for further research.

5.2 Implications for Policy

In section 4.2.2.1 (German Carbon Lock-in) it is summarized and argued that there is little doubt that the German electricity market is to some extent locked in by carbon-intensive coal-fired production. However, the findings in section 4.2.1 demonstrate that the future of coal is highly dependent on the operational expenditure going forward, which is greatly dictated by the cost of emitting CO_2. As demonstrated in section 3.2.3.6, the CO_2-price is vastly policy driven - Germany and 30 other European countries have initiated the EU emission trading system (EU ETS) which has introduced a set cap on the total amount of GHG that can be emitted. With time, this cap is reduced, driving emission reduction. With the cap, companies receive or buy emission allowances. However, the assumption of a policy regime in change can be drawn from the current situation in the United Kingdom. The UK introduced the Carbon Price Floor (CPF) on 1 April 2013. CPF is a UK Government policy implemented in addition to the EU ETS, consequently, promoting carbon pricing at levels which highly encourage low carbon investments (Figure 3.9).

The most aggressive policy scenario for the European Union, namely the *sustainable development scenario* has estimated that a CO_2-price of $140 per tonne CO_2 is required in Europe by 2040 to reach the 2-degree target convened by the Paris Agreement, as a set of guidelines for participating nations to transition away from fossil fuels. However, it is worth mentioning that this is one of several requirements, and the IEA predicts that even in this scenario there is a 50% chance of limiting temperature rise to below 2 degrees Celsius. Consequently, questioning whether or not the objectives of the Paris Agreement are unrealistic and overoptimistic.

However, domestically in Germany in the short-term, the results from section 4.2.1 show that on a theoretical level coal won't be competitive already in mid-year 2021 with the current/existing policy scenario (CPS) and 10% CAPEX reduction for solar PV and onshore wind, with point of competitiveness at 0.135 and 0.138 USD per kWh respectively. These findings indicate that there is no theoretical lock-in based on costs because it would be profitable to scrap coal plants and initiate solar PV and/or onshore wind projects. i.e. indicating that renewables will replace coal in Germany from 2021 with the current development in CO_2-prices and a 10% CAPEX reduction of renewables. Nevertheless, these theoretical points of competitiveness are too simple as they leave out many considerations which have been discussed in section 4.2.2.3 (shortcomings) and above in section 5.2.2 (methodical limitations).

The competitive situation of coal-fired generation can be directly compared with the situation in the UK. Since the introduction of the Carbon Price Floor, there has been a significant decline in electricity generation from coal-fired technologies in the UK. In 2015 the CPF of 18 GDP per tonne ($24) was already far from economically sustainable for domestic coal-fired generation. Since 2012, the electricity produced from coal has declined from 42% to 7% in 2017. Additionally, the UK government has recently introduced an implementation plan (2018), consequently, initiating coal-fired power plant phase-out by 2025 (EIA, 2018a).

A similar plan has recently been implemented for coal-fired generation in Germany. In January 2019 Germany's coal exit commission ruled in favour of phasing out all coal-fired power stations by 2038. Germany currently has an installed utility-scale coal-fired capacity of 40.8 GW, 12.5 GW of which will be decommissioned before 2022, and an additional 12.5 GW before 2030. Germany hopes to decommission the remaining 15.8 GW before 2035, and certainly by 2038 at the latest. Although the phase-out year is much later than what many other European countries have set, Germany was one of the major missing pieces of the puzzle and seeing them commit to a phase-out year is a step in the right direction for the EU to transition to a competitive low carbon economy, paving the way for international readiness for emission reduction by increased political will and public focus.

Independent of what kind of scenarios which are most likely to apply for the future, there is little uncertainty that the price of CO_2 will increase with time. Thus, weakening the business case of coal-fired generation, and consequently reducing carbon lock-in in Germany going forward. This can be directly attributed to the introduction of the new EU ETS policy reform, Market Stability Reserve (MSR), which was initiated in January 2019 in order to reduce surplus allowances in the carbon market - creating an increasingly punitive pricing environment for emission-intensive fuels.

The EU ETS CO_2 price has recovered to levels slightly below $30 per ton in early May 2019, compared to prices in the $20-25 range in March and the first half of April, and an all-time-high of $31 per ton on the 17th of April. Subsequently further pressuring coal-fired power plants with rising generation cost and increased competition from cheaper alternative and less emission-intensive power generation sources.

As initially concluded, the cost competitiveness of solar PV will surpass coal in 2021. With the current policy landscape (*current policies scenario*) and forecasted likely policy scenario (*new policies scenario*), it is likely that the same will happen within 2020. Comparing these scenarios to the current carbon pricing policy regime, it is reasonable to state that this outcome is likely in the mediate term.

Consequently, after 2021, a theoretical investment decision should benefit new solar PV installations rather than favouring the continuance of existing coal plants. In fact, within the theoretical *sustainable development scenario* for coal with the high case for CO_2 prices, coal assets were already less cost competitive than the base case for solar PV in 2017. This implies that the competitiveness of renewable energy highly depends on the implications for policies, such as CO_2 prices, and that utility owners need to take into account the impact of decreased CAPEX for new renewable installations and increased CO_2 price (dictating OPEX) for existing coal-fired plants along with the theoretical points of competitiveness going forward.

5.3 Implications for Future Research

As discussed in section 4.2.2.3 (shortcomings) and above in section 5.2.2 (methodical limitations) - the use of LCOE calculations might not be the ideal tool in order to evaluate new energy investments. As discussed in section 3.1.1, the LCOE is comparable to the concept of break-even (payback) for energy systems. But, instead of measuring how much is needed to recover the initial investment, the LCOE evaluates how much money must be made per unit of electricity (E.g. kWh) to recoup the lifetime cost of the system. LCOE is also highly standardized, meaning that it is difficult to exactly estimate changes in variable costs going forward. As it exists a lot of varying variables and assumptions for LCOE calculations, it can also be difficult to compare them. This is worth having in mind for further research.

Additionally, in order to further evaluate the competitiveness of renewable energy and looking at the investment dynamics within any electricity market, it would be an advantage to include the electricity price, while also evaluating the merit order of production in order to get the broad idea, whether or not to invest in new RE capacity. Future research would preferably include looking at these aspects.

Furthermore, under the assumption that the most recent solar PV installations, e.g. 2016-2018, give the best estimate of the future cost - future research ought to compare LCOE estimations of newer projects, preferably 2016-2018. Lastly, implications for future research could include a quantification of what fractions of coal-fired power production in Germany which becomes uncompetitive at what time.

6 Acknowledgements

I would like to thank Dr. E (Enno) Schröder, Prof. Dr. C.P. (Cees) van Beers and Dr. H (Hadi) Asghari of Technische Universiteit Delft (TU Delft), Dr. E (Erik) Wold, Ricardo Pimentel and Susanne Andresen of Rystad Energy for helpful input. Data was provided by PowerCube Pilot on behalf of Rystad Energy research and analysis.

7 Bibliography

AGEB (2012) *AG Energiebilanzen e.V.* Available at: https://www.ag-energiebilanzen.de/28-0-Zusatzinformationen.html (Accessed: 17 July 2018).

Amelang, S. (2016) *The reform of the Renewable Energy Act. Clean Energy Wire*. Available at: https://www.cleanenergywire.org/dossiers/reform-renewable-energy-act (Accessed: 19 September 2018).

ASTM (2018) *ASTM D388 - 18. Standard Classification of Coals by Rank*. Available at: https://www.astm.org/Standards/D388.htm (Accessed: 9 November 2018).

Bloomberg (2017) *Germany Is Burning Too Much Coal - Bloomberg*. Available at: https://www.bloomberg.com/view/articles/2017-11-14/germany-is-burning-too-much-coal (Accessed: 27 March 2018).

BMWI (2010) *Energy Concept*. Available at: www.bmwi.dewww.bmu.de (Accessed: 20 September 2018).

BMWI (2016) *Sechster Monitoring-Bericht zur Energiewende*. Available at: www.bmwi.de (Accessed: 24 September 2018).

BMWI (2018) *Stellungnahme zum sechsten Monitoring-Bericht der Bundesregierung für das Berichtsjahr 2016. Kommission zum Monitoring-Prozess*. Available at: https://www.bmwi.de/Redaktion/DE/Downloads/S-T/stellungnahme-der-expertenkommission-zum-sechsten-monitoring-bericht.pdf?__blob=publicationFile (Accessed: 30 November 2018).

Borenstein, S. (2012) 'The Private and Public Economics of Renewable Electricity Generation'. doi: 10.1257/jep.26.1.67.

CEP (2014) 'OFFSHORE WIND PROJECT COST OUTLOOK 2014 EDITION. Clean Energy Pipeline'. Available at: http://www.cleanenergypipeline.com/Resources/CE/ResearchReports/Offshore Wind Project Cost Outlook.pdf (Accessed: 18 July 2018).

CEW (2017a) *A timeline of Germany's Energiewende*. Available at: https://www.cleanenergywire.org/factsheets/very-brief-timeline-germanys-energiewende (Accessed: 19 September 2018).

CEW (2017b) *Germany's Energiewende: Find your way around the energy transtion*. Available at: https://www.cleanenergywire.org/dossiers/germanys-energiewende-easy-guide (Accessed: 7 May 2018).

CEW (2018) *Climate goal failure warrants high Energiewende priority-gov advisors. Clean Energy Wire*. Available at: https://www.cleanenergywire.org/news/climate-goal-failure-warrants-high-energiewende-priority-gov-advisors (Accessed: 30 November 2018).

CT (2018) *Carbon Countdown: Prices and Politics in the EU-ETS - Carbon Tracker Initiative*. Available at: https://www.carbontracker.org/reports/carbon-countdown/ (Accessed: 17 September 2018).

Davis et al, S. (2010) 'Future CO2 Emissions and Climate Change from Existing Energy Infrastructure', *Energy*, 243116(September), pp. 1330–1334.

DEA (2015) 'FINDING YOUR CHEAPEST WAY TO A LOW CARBON FUTURE The

Danish Levelized Cost of Energy Calculator'. Available at: https://ens.dk/sites/ens.dk/files/Globalcooperation/vejledning_lcoe_calculator.pdf (Accessed: 13 March 2018).

DEBRIV (2016) *Lignite in Germany. Facts and Figures*. Available at: www.braunkohle.de (Accessed: 4 December 2018).

Deutch, J. (2007) *The Future of Coal. An interdisciplinary MIT study*. Available at: http://web.mit.edu/coal/The_Future_of_Coal.pdf (Accessed: 9 November 2018).

DW (2017a) *Germany's coal exit: jobs first, then the climate. Deutsche Welle*. Available at: https://www.dw.com/en/germanys-coal-exit-jobs-first-then-the-climate/a-44046848 (Accessed: 30 October 2018).

DW (2017b) *The end of an era: hard coal in Germany. Deutsche Welle*. Available at: https://www.dw.com/en/the-end-of-an-era-hard-coal-in-germany/a-43545024 (Accessed: 15 October 2018).

EC (2018) *EU Emissions Trading System (EU ETS). European Commission*. Available at: https://ec.europa.eu/clima/policies/ets_en (Accessed: 8 November 2018).

EIA (2016) *Carbon Dioxide Emissions Coefficients. the U.S. Energy Information Administration (EIA)*. Available at: https://www.eia.gov/environment/emissions/co2_vol_mass.php (Accessed: 7 November 2018).

EIA (2018a) *Coal power generation declines in United Kingdom as natural gas, renewables grow. U.S. Energy Information Administration (EIA)*. Available at: https://www.eia.gov/todayinenergy/detail.php?id=35912 (Accessed: 9 November 2018).

EIA (2018b) 'Levelized Cost and Levelized Avoided Cost of New Generation Resources in the Annual Energy Outlook 2018'. Available at: https://www.eia.gov/outlooks/aeo/pdf/electricity_generation.pdf (Accessed: 11 July 2018).

EN (2018) *Energy Numbers. Germany's offshore wind capacity factors*. Available at: http://energynumbers.info/germanys-offshore-wind-capacity-factors (Accessed: 17 July 2018).

EPA (2014) *Global Greenhouse Gas Emissions Data*. Available at: https://www.epa.gov/ghgemissions/global-greenhouse-gas-emissions-data (Accessed: 2 July 2018).

EPA (2018) *Summary of the Clean Air Act*. Available at: https://www.epa.gov/laws-regulations/summary-clean-air-act (Accessed: 24 April 2018).

Erickson, P. *et al.* (2015) 'Assessing carbon lock-in', *Environmental Research Letters*. IOP Publishing, 10(8), p. 84023. doi: 10.1088/1748-9326/10/8/084023.

European Commission (2011) 'A Roadmap for moving to a competitive low carbon economy in 2050'. Available at: http://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:52011DC0112&from=EN (Accessed: 6 March 2018).

FMEAE (2015) *Expertenkommission zum Monitoring-Prozess. Energie der Zukunft. Stellungnahme zum vierten Monitoring-Bericht der Bundesregierung für das Berichtsjahr 2014 Kommission zum Monitoring-Prozess*. Available at: https://www.bmwi.de/Redaktion/DE/Downloads/M-O/monitoringbericht-energie-der-zukunft-stellungnahme-2014.pdf?__blob=publicationFile&v=3 (Accessed: 19 September 2018).

Fraunhofer (2018) *Power generation in Germany - assessment of 2017*. Available at: www.energy-charts.de (Accessed: 30 July 2018).

FS (2017) 'Global Trends in Renewable Energy Investment 2017'. Available at: http://fs-unep-centre.org/sites/default/files/publications/globaltrendsinrenewableenergyinvestment2017.pdf (Accessed: 15 March 2018).

FT (2018) *Energy shift fails to cut German carbon. Financial Times*. Available at: https://www.ft.com/content/1ce68966-bffe-11e8-95b1-d36dfef1b89a (Accessed: 4 December 2018).

GABI (2014) *Energiewende Today: Status of Germany's Energy Transition – Global America Business Institute*. Available at: http://thegabi.com/energiewende-today-status-of-germanys-energy-transition/ (Accessed: 30 November 2018).

Goyal, R. *et al.* (2018) *State and Trends of Carbon Pricing 2018. World Bank Group*. doi: 10.1596/978-1-4648-1292-7.

Hirst, D. (2018) 'Carbon Price Floor (CPF) and the price support mechanism. Number 05927. House of Commons Library', (05927).

HP (2013) *Up To Date Cost Curves for Batteries, Solar and Wind. The Handleman Post*. Available at: https://handlemanpost.wordpress.com/2013/12/06/up-to-date-cost-curves-for-batteries-solar-and-wind/ (Accessed: 18 July 2018).

Hvalbye, O. (2019) 'German shift from coal to renewables will drive up demand for gas', pp. 2019–2021.

IEA (2015a) 'Projected Costs of Generating Electricity'. Available at: https://www.iea.org/publications/freepublications/publication/ElecCost2015.pdf (Accessed: 22 February 2018).

IEA (2015b) 'World Energy Outlook 2015. International Energy Agency'. Available at: www.iea.org/t&c (Accessed: 19 July 2018).

IEA (2017) *Key world energy statistics*. Available at: https://www.iea.org/publications/freepublications/publication/KeyWorld2017.pdf (Accessed: 26 July 2018).

IEEFA (2016) *The Dutch Coal Mistake*. Available at: http://ieefa.org/wp-content/uploads/2016/11/The-Dutch-Coal-Mistake_November-2016.pdf (Accessed: 16 October 2018).

IPC (2018) 'CARBON LOCK-IN IN TURKEY A COMPARATIVE PERSPECTIVE OF LOW-CARBON TRANSITION WITH GERMANY AND POLAND'. Available at: http://ipc.sabanciuniv.edu/wp-content/uploads/2018/02/CarbonLockin_Şahin_ENG.pdf (Accessed: 5 March 2018).

IPCC (2014) 'Summary for Policymakers'. Available at: https://www.ipcc.ch/pdf/assessment-report/ar5/wg3/drafts/fgd/ipcc_wg3_ar5_summary-for-policymakers_approved.pdf (Accessed: 23 April 2018).

IRENA (2012) 'RENEWABLE ENERGY TECHNOLOGIES: COST ANALYSIS SERIES'.

Available at: www.irena.org/Publications (Accessed: 10 July 2018).

IRENA (2017) ‘Renewable power generation costs in 2017: Key findings and executive summary’. Available at: https://www.irena.org/-/media/Files/IRENA/Agency/Publication/2018/Jan/IRENA_2017_Power_Costs_2018_summary.pdf?la=en&hash=6A74B8D3F7931DEF00AB88BD3B339CAE180D11C3 (Accessed: 4 March 2018).

IRENA (2018) *Technology Roadmap, SpringerReference*. doi: 10.1007/SpringerReference_7300.

King, H. M. (2018) ‘Coal. What Is Coal and How Does It Form?’ Available at: https://geology.com/rocks/coal.shtml (Accessed: 7 November 2018).

Kost, C. *et al.* (2018) *LEVELIZED COST OF ELECTRICITY RENEWABLE ENERGY TECHNOLOGIES*. Available at: www.ise.fraunhofer.de (Accessed: 3 April 2019).

Kuittinen, H. and Velte, D. (2018) *Case Study Report Energiewende. European Commission*. doi: 10.2777/835267.

Lehmann, P. *et al.* (2012) ‘Carbon lock-out: Advancing renewable energy policy in Europe’, *Energies*, 5(2), pp. 323–354. doi: 10.3390/en5020323.

PowerTech, V. (2015) ‘Levelised Cost of Electricity’. Available at: www.vgb.org (Accessed: 23 February 2018).

PT (2014) *Power plant O&M: how does the industry stack up on cost? - Power Technology*. Available at: https://www.power-technology.com/features/featurepower-plant-om-how-does-the-industry-stack-up-on-cost-4417756/ (Accessed: 11 July 2018).

Schlissel, D., Smith, A. and Wilson, R. (2008) *Coal-Fired Power Plant Construction Costs*. Available at: http://schlissel-technical.com/docs/reports_35.pdf (Accessed: 13 November 2018).

Schmalensee, R. (2012) *Energy Decisions, Markets, and Policies*. Available at: https://ocw.mit.edu/courses/sloan-school-of-management/15-031j-energy-decisions-markets-and-policies-spring-2012/# (Accessed: 23 April 2018).

Seto, K. C. *et al.* (2016) ‘Carbon Lock-In: Types, Causes, and Policy Implications’. doi: 10.1146/annurev-environ-110615-085934.

Smil, V. (2010) *Energy Transitions: History, Requirements, Prospects*. Available at: http://library.aceondo.net/ebooks/HISTORY/Energy_Transitions__History__Requirements__Prospects.pdf (Accessed: 26 July 2018).

UNFCCC (2018a) *Success of COP24 in Katowice – we have a global climate agreement*. Available at: https://cop24.gov.pl/news/news-details/news/success-of-cop24-in-katowice-we-have-a-global-climate-agreement/ (Accessed: 29 December 2018).

UNFCCC (2018b) *UNFCCC eHandbook*. Available at: http://bigpicture.unfccc.int/#content-the-paris-agreemen (Accessed: 6 March 2018).

Unruh, G. C. (2000) ‘Understanding carbon lock-in’. Available at: https://ac.els-cdn.com/S0301421500000707/1-s2.0-S0301421500000707-main.pdf?_tid=spdf-aca68d30-48e4-4b5b-92fc-21cbd50f0e72&acdnat=1519905481_c24abfb1b9446697ecc0328d42e2fe0c (Accessed: 1 March 2018).

VDMA (2017) 'THE COST OF ONSHORE WIND POWER IN GERMANY - n Verband Deutscher Maschinenund Anlagenbau e. V'. Available at: https://ps.vdma.org/documents/106078/2159140/Cost Study Wind Energy Summary/fa78ee31-3e04-40c0-a7e4-9889af7a4a98 (Accessed: 11 July 2018).

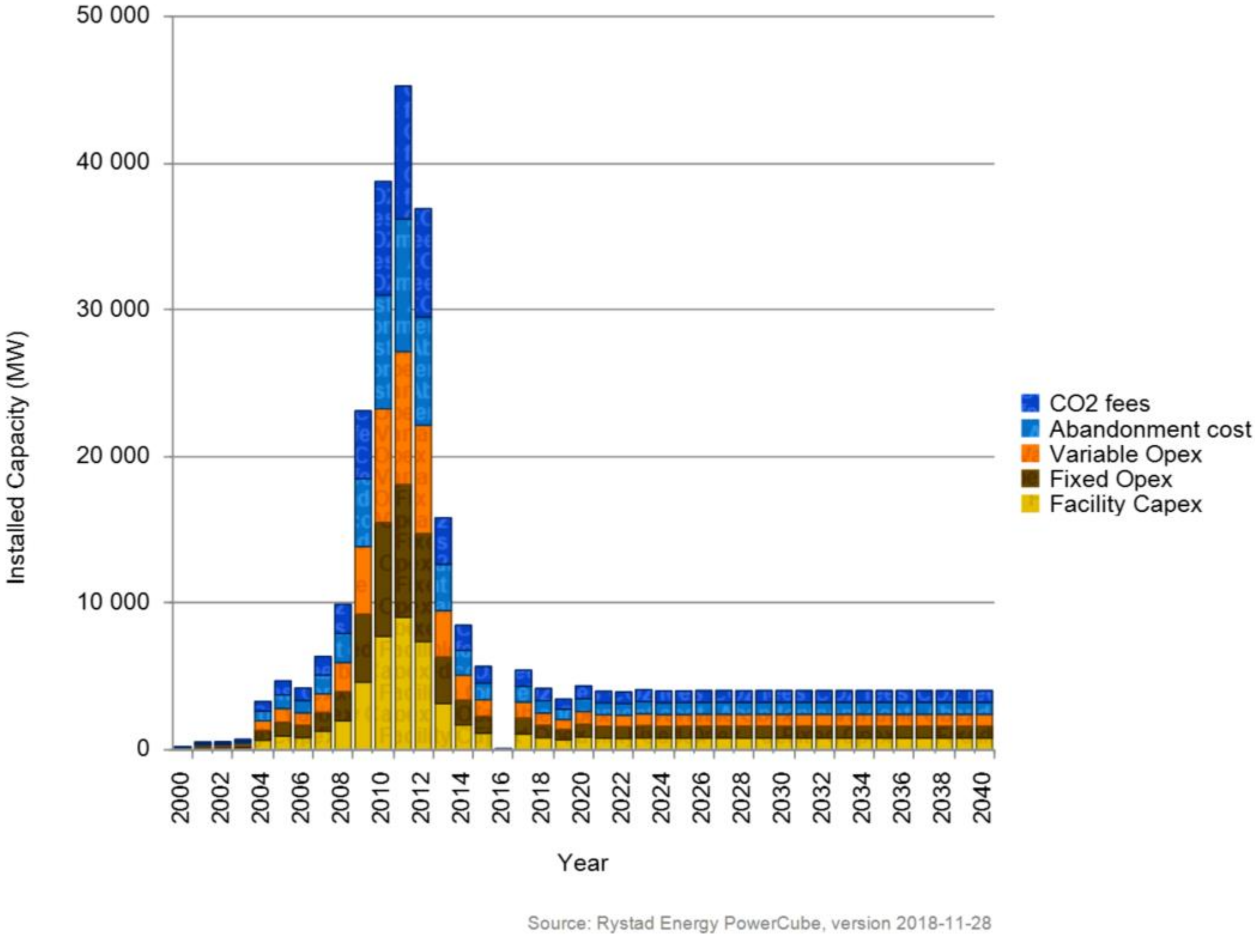
WEC (2016) 'World Energy Resources Wind. 2016. World Energy Council'. Available at: https://www.worldenergy.org/wp-content/uploads/2017/03/WEResources_Wind_2016.pdf (Accessed: 12 July 2018).

WECC (2017) 'Western Electricity Coordinating Council', in. doi: 10.1109/PESGM.2012.6344973.

Zweifel et al, P. (2017) *Energy Economics, Theory and Application*. Springer. doi: 10.1016/j.eneco.2008.05.005.

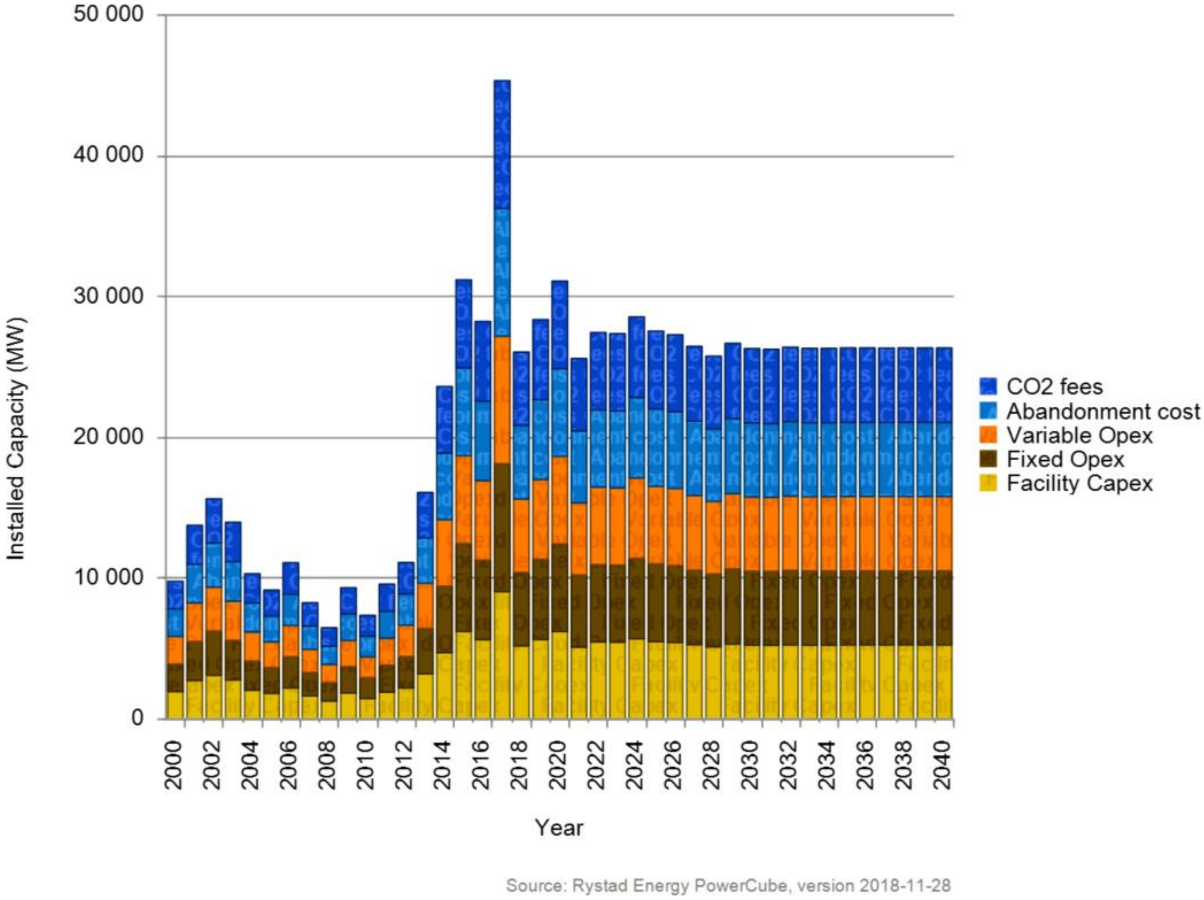
8 Appendix

Table A10: Annually installed capacity of Solar (w. economic split) in the German electricity market 2000-2040



Source: (Rystad Energy, 2018)

Table A11: Annually installed capacity of Wind (w. economic split) in the German electricity market 2000-2040



Source: (Rystad Energy, 2018)