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The impact of renewable support schemes on electricity markets – a model-based analysis

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To my family

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List of Abbreviations and Symbols

€/MWh .... Euro per Mega Watt Hour

BMU .... Ministry for Environment

CO_2 .... Carbon Dioxide

EEG .... Renewable Energy Sources Act

EEX .... European Energy Exchange

EU .... European Union

FiP .... Feed-in Premium Scheme

FiT .... Feed-in Tariff

FIT .... Feed in Tariff

FLH .... Full Load Hours

GOT .... Grid Operator Trader support design

GW .... Giga Watt

GWh .... Giga Watt Hours

LCOE .... Levelized Costs of Energy

MC .... Marginal Costs

MV .... Market Value

MVF .... Market Value Factor

MW .... Mega Watt

N .... hours in the year/month

NREAP .... National Renewable Energy Action Plans

OM .... Open Markets

OTC .... Over the Counter

p_h ....spot market hourly price

PV ....Solar Photovoltaic Power; Photovoltaic

PVR...Photovoltaic on Roof

RE .... Renewable Energy; Renewable Energy

RES .... Renewable Energy Source

SP ....Sliding Premium

TSO .... Transmission System Operator

VRE ....Variable Renewable Energy; Variable renewable Energy

ζ ....Number of hours with negative price

σ .... standard deviation of the hourly spot market prices

Abstract

The share of the renewable energies in the power market is steadily increasing. The penetration of the renewable energies has a strong impact on the power market, especially the variable energy sources. The negative correlation of RES-E in-feed and the power prices, known as merit-order effect, have already been discussed in the literature as well as some of the parameters that influence it. To the author´s knowledge there is no quantitative studies about the impact on the market prices due to the bidding behaviour of the renewable energies. As power systems increase in complexity due to higher shares of intermitting RES-E, is also increasing the requirements for power system modeling. With Germany as example, this dissertation seeks to discuss to what degree the impact on the electricity price due to the increasing RES-E share could be mitigated by optimizing the design of the support scheme. The results suggest that the sliding-premium scheme have high potential compared to the feed-in tariff or fixed-premium in terms of savings to both the consumers and conventional generator side, considering that it keeps the income flow to the renewable generators constant. The main critic that is moved to the sliding feed-in premium is the higher initial costs due to the management premium. The results show that the reduction of the costs due the variability of the premium still permits savings compared to the other schemes. Furthermore, the result suggests that the additional benefit due to the direct market, in terms of less price distortions, could be considered secondary to the higher risk of over-/under-compensation, i.e. if is used a capacity reward mechanism, for the variable renewables. Therefore in the author´s point of view the optimal design should be a mix of open market and sliding premium depending on the technology. In the dissertation is also analysed the effect of the interconnection of the spot market with the reserve market.

1 Introduction

1.1 Background

The scientific opinion on climate change is that the “warming of the climate system is unequivocal, as is now evident from observations of increases in global average air and ocean temperatures, widespread melting of snow and ice and rising global average sea level” (IPCC, 2007). “There is very high confidence that the average net effect of human activities since 1750 has been one of warming [...]” (IPCC, 2007). Unmitigated climate change would, in the long term, be likely to exceed the capacity of natural and human systems to adapt. Burning fossil fuels and deforestation are the human activities that mainly increase the concentration of greenhouse gasses in the atmosphere. Furthermore fossil fuel reserves are finite, due to the long time that they need to reform and to the wide-scale extractions that started from the Industrial Revolution.

The European Union (EU) made a choice to support Renewable Energy Sources (RESs) in 2001 with a Directive that concerned the support to these energy sources in order to create a level playing field (Lorenzoni, 2010).The EU has a clear framework to steer its energy and climate policies; this framework integrates different policy objectives such as reducing greenhouse gas emissions, securing energy supply and support growth, competitiveness and jobs through high technology (European Commission, 2013). The renewable energies (REs) need to be supported because the market does not provide the optimal level of renewables without public intervention. “This is due to market and regulatory failures: low level of competition and unfair competition with other fuels, in particular subsides for fossil fuels and nuclear energy, […] the incomplete internalization of external costs (air pollution and energy security), rigid electricity system design inhibit the growth of renewable energy” (European Commission, 2013 a). The share of renewables in EU shall reach 35% of the electricity consumption by 2020 and 60-80% in 2050, up from 23.5% in 2012[1].

As the hydropower potentials are mostly exploited in many regions, biofuel-fired plants are limited by supply constraints and sustainability concerns, big part of the generation will need to come from solar and wind power. Wind and solar are intermittent energy sources in the sense that their output depends on weather conditions (Hirth, 2013). In addition to the fluctuation of the demand, the stochastic nature of the variable renewable energies (VREs) is increasingly challenging for the supply side of the power systems (Nicolosi, Fürsch , 2009). In a thermal power system[2], with a high share of VRE, during windy and sunny hours, the VRE itself could lead to the drop of the prices, due to the well-known economic result that in oversupply situation the price decreases. Hence when the VRE generators have the possibility to generate the energy price is low; consequentially their rents are low as well. This can lead to an increase of public subsidies in order to increase the renewable share.

The penetration of the renewable energies has a strong impact on the power market, especially the variable energy sources. The main impacts of the renewable on the power market are the reduction of the average utilization of the conventional fleet, the future investments on conventional technologies, reduction of the average market price and increase the volatility of the spot market prices.

1.2 Research case

Since Germany has a rigid thermal power system the integration of the renewable has even more severe impacts than to countries with a high share of hydro power with possibility of storing the energy. Furthermore, the German power market is the biggest

[1] The National targets for 2020 are formulated in (European Commission, 2010), and the European targets for 2050 in (European Commission, 2011). The historical are retrieved from (Eurostat, 2014).

[2] A Thermal power system is an electricity system in which the majority of the energy is obtained from the thermal conversion. These systems often have small possibilities to have energy storages. They are also known as “capacity constrain” system whereas a “hydro system” is energy constrain due to the hydro storages.

European market, when it comes to consumption (Nicolosi, 2011). Therefore, Germany is considered a good research case for study the integration of the VRE in the market, while keeping the subsidies costs down.

Anyway since many other European countries have a rigid thermal power system the findings could be easily adapted.

1.3 Objective

The negative correlation of RES-E in-feed and the power prices have already been discussed in the literature, and this is known as merit-order effect. The volume of the merit-order effect is influenced by factors as the CO_2 price, fuels cost, and the type of the conventional fleet (in section 2 is presented the literature review).

Many mechanisms are suitable for support the renewables in the electricity market. In the literature seems that one important feature of a support scheme is the compatibility with the liberalized market, the more compatible designs are called market-oriented support schemes. The type of support mechanism influences the power market in two ways: different capacity installations, thus different renewable portfolios, and the way in which renewables participate in the electricity market.

Recent studies, (Winkler J. et al., 2013), analysed the impact due to the resulting renewable portfolios in Europe. Contrary to the expectations the more market oriented scheme does not necessarily have less impact on the market prices.

To the author´s knowledge there are no quantitative studies about the impact on the market prices due to the bidding behaviour of the renewable energies, therefore is considered important to fill the knowledge gap with an modeling study.

The aim of the work at hand is to analyze how different support policies for renewables affect the power market in order to asses which could be the best way to support the RESs at the least public cost, on the example of Germany.

1.4 Used Approach

As power systems increase in complexity due to higher shares of intermitting RES-E, is also increasing the requirements for power system modeling.

This thesis was carried out with the Fraunhofer ISI in Karlsruhe. This research team developed a model labelled PowerACE cluster system that seeks to simulate the central processes regarding the trading, generation and distribution of electricity in Europe with several modules.

PowerACE is an agent-based model implemented in the programming language JAVA[3], the markets represented in the model include the day-ahead and reserve markets, but it also deals with other aspects of the power market, such as electric mobility and the retail market. Furthermore embedded in the PowerACE cluster system there is a capacity optimization module.

For study the impact of the bidding behaviour of the renewable energies where implemented a new part of the code where the support scheme can be chosen and consequentially the bidding behaviour changes.

Furthermore, in order to use it as input data for the model, , according the EEGs and the National Renewable Energy Action Plans (NREAP), a possible development of the capacity, generation, feed-in tariff support value, of the renewable energies, up to 2030 in Germany were developed.

1.5 Structure of this thesis

The remainder of this report is structured as follows: in chapter 2 a general framework of the state of art in this field is given towards better understand the results that are going to be exposed in section 4, and the discussion of them in section 5.

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[3] Java is a open source program, available at: https://www.java.com/it/download/.

Chapter 3 present the methodology used to reach the objective. Are explained in detail the taken assumptions on the input data how they were retrieved. Afterwards is explained the used model, and how it was build the new part regarding the bidding behaviour. Moreover, is given an overview of the used simulation scenarios.

Chapter 4 presents the model results of the considered simulations, whereas in chapter 5 the results are discussed and is evaluated the impact of the support mechanisms on the power market. Moreover in this section is tried to answer to the question: which could be the best support scheme for the renewables?

Finally, chapter 6 summarizes the dissertation and the findings, the limitation of the analysis are discussed and possible future works are presented.

2 Theoretical Framework and Literature review

This chapter aims to give a general framework to better understand the results that are going to be exposed in section 4, and the discussion of them in section 5. It is considered useful to recall some general framework of the German wholesale electricity market. Is given also a brief description of the support mechanisms for the renewable energies in power systems, with a particular attention on the support schemes analysed in the work at hand.

The electricity is a flow commodity. The main characteristic which distinguishes it from the most of the goods traded in competitive markets is the restriction on storability. Therefore demand and supply have to meet continuously otherwise the line frequency deviates from the aimed value and could cause the break down of system´s components. Furthermore the electricity is essential for the proper functioning of the economy, and the electricity demand is extremely price-inelastic (Winkler J., 2011). This characteristic tends to make the electricity a good subject to high tax level.

The electricity could be generated from different sources and with different technologies; i.e. from the solar energy or nuclear energy, but the final product is completely homogenous, therefore there are limited possibilities on the price differentiation. How the electricity is produced impact on the society in terms of costs and other effects difficult to monetise.

There are some sectors of the economy where the demand and the offer by their own cannot ensure a reasonable balance of the interests of the parties concerned. Many reasons could lead to these unwanted situations, in economy are labelled market failures. Typical examples of market failures could be the presence of factors that cannot be monetised, normally called externalities, for instance the pollution cause health problems and environmental disasters that are difficult to evaluate in terms of additional costs on the product. Other failures are the possibilities for some participants of the market to exert their controls on the others, know as market power, or the presence of scale economies. The electricity sector is traditionally identified liable to the market failures for the special nature of the electricity and to the needs of high investments.

2.1 The German Electricity Markets

This paragraph is based on (Winkler J., 2011) and (Nicolosi, 2011).

The German electricity market is Europe's largest, in terms of consumption (IEA, 2013). Since the early 1990s, as in many other European countries, in Germany the integrated monopolistic utilities were privatized and unbundled (Neuhoff K. et al., 2011). The market share of the four largest power producers is between 70 and 85 percent (Lise W. et al., 2008). The four big utility companies (EnBW, Vattenfall, E.ON, and RWE) are prohibited by the “Law against competition restrictions” to have a behaviour that leads to a not competitive market (BMJ, 2011). Moreover the transmission operators have been legally separated from the main power generators.

The market is an “energy only market”, for instance there are no mechanisms to reward capacity. Electricity is sold at the spot market, in long term futures and forward contracts. Moreover there is a balancing market in which the TSOs organize the ancillary services.

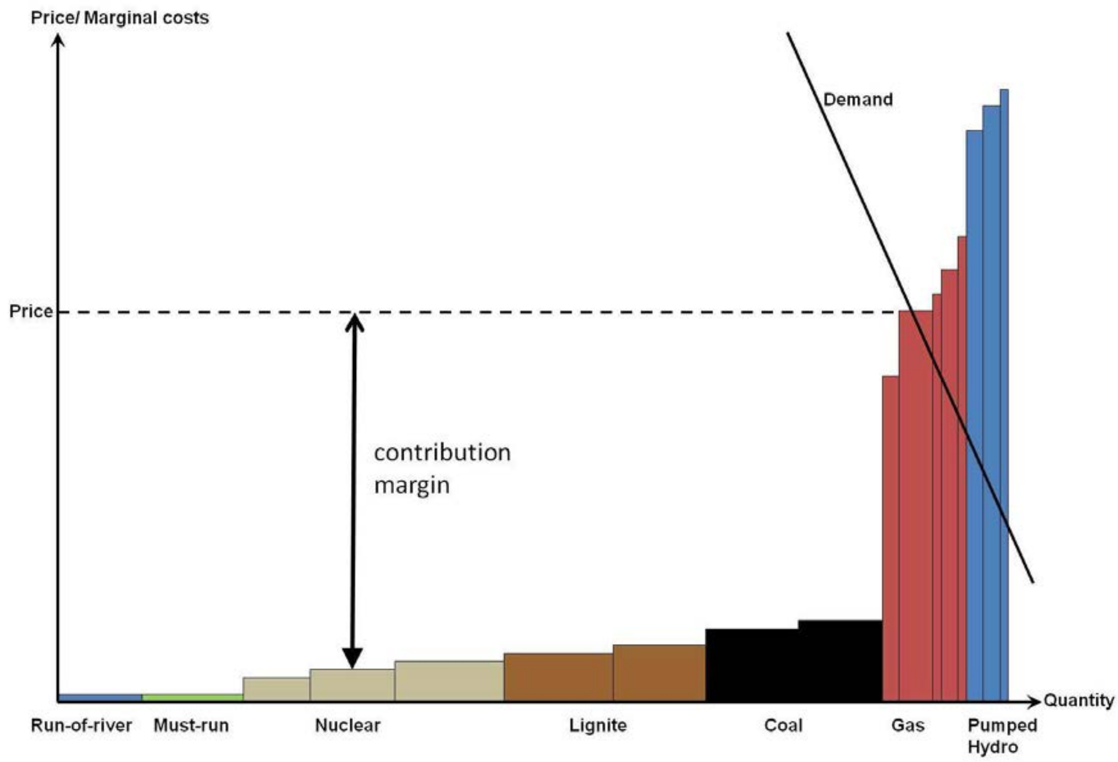
2.1.1 The wholesale market

The German wholesale market is composed of a virtual over-the-counter (OTC) market and the European Energy Exchange (EEX) in Leipzig. The EEX includes the day-ahead market and the intraday market. While the OTC market and the intraday market have a continuous trade, the day-ahead market has a single auction with a gate closure at 12 a.m. on the day before physical delivery. At the day-ahead auction, generators and suppliers bid into the market for trading the electricity of the next day[4]. The bid price has a price cap of 3000 €/MWh, and since September 2008, the EEX has allowed negative price bids.

[4] The offers could be either of one-hour interval or a block offer, useful especially for the big thermal plants with considerable ramping cost normally called base-load plants, i.e. lignite and nuclear thermal power stations.

The market operator sort the offers of the generators from the cheapest to the most expensive in order to generate a supply curve that represent the economic merit of the plants, usually know as *merit-order curve*. The price settling mechanism at the EEX is a uniform price auction, thus the price is set by the last plant called to produce. Figure 2.1 shows how is set the price in the day-ahead auction.

Figure 2.1 : Stylized German merit order curve.



Source: (Winkler J., 2011)

Although two third of the trading volume is settled via bilateral OTC contracts, the market clearing price of the central day-ahead auction is used a benchmark and reference point for the other electricity markets. This is due to the liquidity of the day-ahead market that allows arbitrage mechanisms . However is still possible that in the other markets the price deviate from the day-ahead EEX price, due to different level of information or to the risk perceptions.

Between the day-ahead market closure and 75 minutes before real time, trade is still possible at the intraday market. Anyway, the biggest part of the trades is settled with the gate closure of the central day-ahead auction. The intraday market lacks of liquidity due to the continuous trading. Therefore the resulting market price is not a valid benchmark. In the intraday market the traders have the possibility to balance their position, i.e. to react to unexpected variation of the demand or variation of the forecasted generation for the renewable generators.

2.1.2 The reserve market

The 75 minutes before physical delivery the responsibility to balance the grid is passed to the reserve power market, which is operated by the TSOs. Within this time frame, they are obligated to balance the deviations between supply and demand. The increasing penetration of the fluctuating renewable energies makes more difficult the grid balance due to forecast errors of their generation.

The balancing energy is divided into positive and negative reserve. As in other European countries the reserve are distinguished as primary, secondary and tertiary reserves. Primary reserve is automatically activated and has to react instantly in case of frequency imbalances. The primary balancing energy is responsible for the first five minutes; afterwards the secondary reserve is automatically activated for the following 10 minutes. Primary and secondary reserve are also called spinning reserve because the generators that take part have to be operative and on line. Tertiary reserve are activated manually by the TSOs and needs to be online within 15 minutes, therefore can also be met by non-spinning reserves and e.g. by open cycle gas turbines with short start-up times.

Primary and secondary balancing energy are auctioned every week, whereas tertiary reserve is auctioned every workday. Therefore the power plants that win the auctions for primary and secondary reserve are obliged to stay online for the entire month. In other words they are forced to offer in the spot market a certain share of their load to a low price in order to be on-line. The power plants that supply the negative reserve have to bring on-line a margin above their minimal load according to the contracted restriction in order to reduce the generation when required.

In order to participate in the auctions for balancing energy are required a technical prequalification and framework agreement with the TSO. So far, fluctuating electricity generation has not been integrated in the reserve market. The possibility to take part of the reserve market is becoming a relevant topic to increase the overall flexibility of the power market.

2.2 The integration of the Renewable energies

The complete integration of the renewable energies in the electricity sector is a challenge. As hydropower potentials are mostly exploited, biofuel-fired plants are limited by supply constraints and sustainability concerns, big part of the generation will need to come from solar and wind power (Hirth, 2013). Wind and solar are intermittent energy sources in the sense that their output depends on weather conditions. The fluctuating generation of the partially dispatchable generators coupled with stochastic variation of the demand make more difficult to meet continuously the supply and the demand, and the cost for balancing the system is expect to grow considerably (Klobasa et al., 2013).

In recent studies, i.e. (Nicolosi, 2011), (Schill P., 2013) the residual demand is used for asses the challenging that has to face the supply system. The residual demand is the load that has to be served by the generators that are “active in the market”. Practically, is obtained as demand minus the supply generation that is not influenced directly by the demand, as the renewables generation and the “must-run” contracted capacity for supply the reserve. The capacity contracted for the primary and secondary balancing energy has to be on-line thus they are independent to the demand fluctuations. The renewable generation is usually subtracted from the demand because under the feed-in tariff scheme, the TSOs are forced to accept and dispatch the energy product by the RES-E. Under other support schemes, as the premium schemes, the renewables have to participate in the market. Anyway the VRE´s generation is considerable part of the demand side because of its stochastic nature, whereas the dispatchable[5] renewable generators could be easily decoupled to the demand side with more market-oriented policy than the feed-in tariff.

The most important feature of an energy system to bear high fluctuation of the demand is the flexibility.

2.2.1 The flexibility of the Electricity Market

The flexibility of a power market is the ability to efficiently cover the fluctuation of the demand. The flexibility is an issue either in case of low or high demand. The market signals of to the lack of flexibility is the deviation from the usual variable cost based pattern (Nicolosi, 2011).

The flexibility of a system is related to many factors: the capacity mix, the possibility to store energy, the interconnections with inter-/intra-national markets (i.e. the reserve market contract available capacity from the wholesale market thus the interconnection with the reserve reduce the flexibility, whereas the interconnectors between the countries could increase the flexibility of the wholesale market), and the design of the support scheme. For instance in a “hydro system”, as could be considered the power system of the north European countries, the significant amount of possibility to store energy makes the overall flexibility higher than a “thermal system” as could be considered the German power system.

A power system comprising supply, grid infrastructure and demand has a particular level of flexibility, and every components has the own flexibility restrictions. Since the price settlement of the market does not take into account bottlenecks is not considered in the work at hand the flexibility restrictions due to the grid infrastructure

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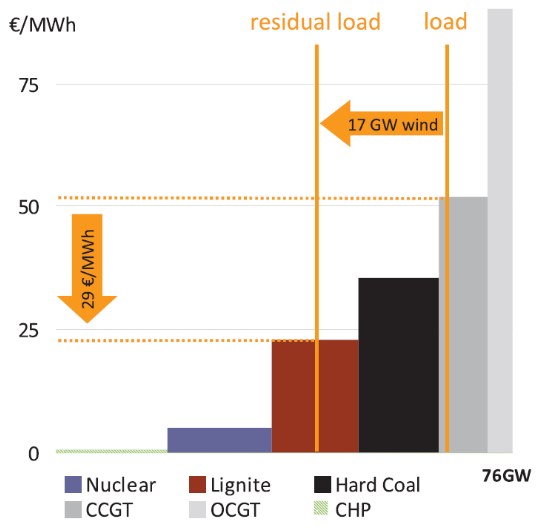
[5] Biofuel-fired plants, hydro power, and geothermal power are usually called dispatchable renewable energy sources. For the biofuel and the geothermal is understandable why the input is considerable constant. For the hydro power the output is dependent on the seasonal water level in the rivers. However, an analysis of published data suggests that the market value of the hydro power can be assumed constant (Klobasa et al., 2013).

In the flexibility of the demand side can be included mainly three factors. Obviously, the natural fluctuation of the load, but has to be considered that the demand is almost price-inelastic. The second factor is the capacity contract for balancing services. The last on is concerning the renewable energy sources. While the VREs may be included in the demand side for their intrinsic stochastic behaviour, the constant renewable generator has to be considered part of the demand side if they are for some reasons always dispatched i.e. the grid priority under the feed-in tariff. Higher is the variability of the demand side higher has to flexibility of the system to keep the prices in the normal variable cost base pattern.

In the supply side the flexibility is determined by the capacity mix, the interconnection with other markets, and the possibility to store the energy. As in the research case the possibility to store energy are limited in the work at hand the flexibility due to energy storages is not presented in-depth, although the possibility of store energy could be an important factor to mitigate the technical inflexibility of the thermal systems and the fluctuating generation of the VREs. The capacity mix has a predominant role in defining the flexibility. Thermal plants are technically inflexible because of the minimum load and the steep decrease of efficiency at the partial load. Thermal Plants with high ratio of fixed costs on the variable costs, as lignite and nuclear, are called base load plants because they have to be operative for a long time in the year for recover the high fix costs. Furthermore, for preserve their life-time these plants should not do often ramping up or down as they are not designed for to it. These technical characteristics have a strong influence on the overall flexibility of the system. For instance, a power block of base load power is willing to reduce the generation to follow the price signals but is already operating at the minimum load, than it should shut off the power plant, before do it the operator have to taking into account the opportunity costs due to the possibility to restart the power plant in time for participate at the power market and the start-up cost. These lead to reduce significantly the flexibility of the entire system. As was explained the capacity held back for system security decreases the supply flexibility. Whereas the interconnections with international market could lead to higher flexibility when there is an international harmonization of the power markets.

The flexibility of the system is important to mitigate the impact of the renewable on the market prices. One of the most known effects of the renewables is the reduction of the average wholesale market price. Since renewables and must-run already cope part of the load the system has just to supply the residual load, thus the price is lower. Figure 2.2 shows the, so-called, *merit-order effect*.

Figure 2.2: Merit order effect during windy hours.



Source: (Hirth, 2013).

2.2.2 Merit-order effect

Although the constant generators in case of more market oriented support scheme could react to the demand, they represent a small part of the renewable fleet. The VREs are mostly influenced on the weather conditions, so they produce energy when they have the possibility. Therefore if the installed capacity of VREs is non marginal, than the VRE supply it self reduces the price during sunny and windy hours by shifting the residual curve (Hirth, 2013). Therefore, **in the same system**, higher is the installed capacity of a certain partially dispatchable energy source higher is the drop of the price, and thus its market value.

Recent studies show that the impact on the merit order effect is mainly driven by the overall share of renewables on the electricity mix but also by the flexibility of the residual system, the market interactions, fuel prices and CO_2 price ((Nicolosi, 2011); (Hirth, 2013); (Sensfuß F. et al., 2008); (Winkler J. et al., 2013)) the impact of these parameters are going to be explained in the following. Furthermore in this thesis is shown that also the renewable support mechanism has a strong impact on the market prices in the periods of high VRE in-feed.

Parameters that influence the merit-order effect

The slope of the supply curve is the most important parameter that determines the volume of the merit order effect (Sensfuß F. et al., 2008). For instance, if the load in Figure 2.2 would be enough high to call the OCGT technology to produce, in this case the merit-order volume would be higher than the one show in the figure, because the variation of the price due to the wind energy is bigger due to the higher slope of the supply curve in the last part.

Among others (Sensfuß F. et al., 2008) and (Hirth, 2013) carried out sensitivity analysis about the fuel and CO_2 prices on the merit-order curve. The parameters that influence the shape of the supply curve are:

1. The capacity mix;
2. The fuels price;
3. The CO_2 price;

The flexibility of the conventional supply system influence the merit-order effect, an optimized system for the renewable has less base load plants therefore the supply curve is more smooth and the system has higher possibility to follow the load fluctuations.

The fuel prices are a driving factor for the energy prices. The impact of the fuel prices on the merit-order effect is related to the impact of the fuel prices on the supply curve. Hence is difficult to asses a priori how the variation of the fuel costs could affect the merit-order. For instance, (Sensfuß F. et al., 2008) shows that the increase of the coal fuel price reduces the merit order effect, because the relative price between gas and coal change and therefore the slope of the merit-order curve reduced.

The CO_2 price determines complex impact on the supply curve, therefore on the merit-order effect. It mainly changes the slope of the supply curve in two different ways:

1.Within the same technology; higher CO_2 price increase the slope of the curve due higher importance of the efficiency;

2.The CO_2 price could move the technology up or down in the supply curve, hence the overall slope of the curve change.

The lack of flexibility in the system coupled with the merit-order effect leads to the surplus situations, since September 2008 in the EEX negative price are allowed to stem the economic losses due to the increasing frequency of surplus situations.The surplus situations occur when the residual demand is lower than zero (for the definition of residual demand see Appendix 1). High share of intermittent renewable energy sources reduces the energy generated from thermal plants, whereas the thermal installed capacity is not reducing much (Hirt, 2012), therefore is expected that the frequency of over-supply in the near future will increase.

Oversupply situations

The oversupply situations occur when the residual load is low, i.e. low demand and high in-feed of VRE, and the system is not enough flexible to follow it. The supply system has to react with shutting off or ramping down conventional power plants; when there is no more possibility to reduce the generation because the plants have to supply the ancillary services[6] or to export, thus the system is in a *firm* situation. These situations lead to the negative prices in the wholesale market.

Hours with negative price in the EEX

For the normal goods the negative price seems counter-intuitive, whereas for the electricity the negative offer is a direct consequence of its particular attributes as the non-storability and the price-inflexibility of the demand.

[6] As explained previously also the base load plants are unwilling to shut off the power plant, so they likely they may be online as well.

In Germany, during the oversupply situations, before the negative prices the energy was cut on with a less efficient pro-rata mechanism, the negative price mechanism permits higher overall welfare and it mirrors the opportunity costs of the power plants (the reasons why the negative prices are more efficient than the pro-rata mechanism is briefly given in (Nicolosi, 2011)). The conventional power plant bid negative into the market when the residual demand is low and they cannot reduce the load or shut off for avoid the high start-/ramping-up costs. Also the renewable generators, active in the market, and supported with mechanism that reward the dispatched energy would bid negative. The negative price is not problematic per se, but is a signal to asses the overall flexibility of the system.

High share of the intermittent renewable energy sources reduces the energy generate from thermal plants, whereas the thermal installed capacity is not reducing much (Hirt, 2012), therefore their utilization decrease. The decrease of the average utilization of the thermal plants increases their specific capital costs. High share of renewables change the load curve of the conventional system therefore efficient long term investment decision are consequence of the market signals (i.e. the merit-order effect). Hence the optimization of a thermal system with high share of RES-E or without renewables has different result. These concepts are going to be explained in the following paragraphs.

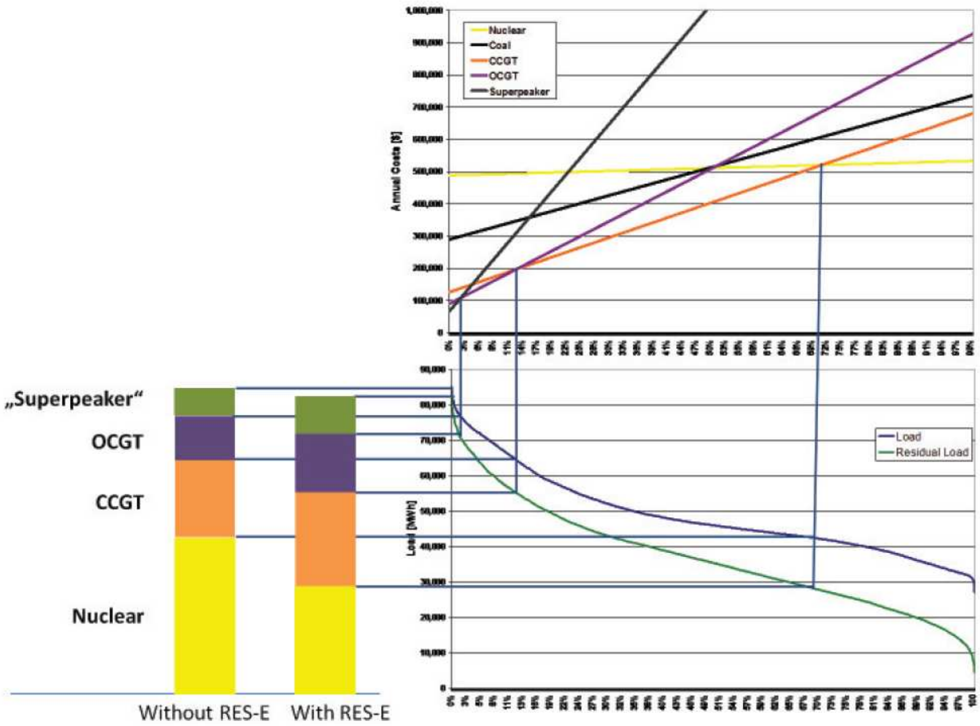
2.2.3 Effects on the conventional fleet

This paragraph is based on (Nicolosi, 2011).

In the short term the high share of renewable energy has the effect to decrease the utilization of the conventional fleet. For instance, in the lower right corner of Figure 2.3, is shown the load and residual load duration curves, in a system with high share of RES-E. In the long run, considering investment decisions, this lead to a less profitability of the base load capacity, since they require high utilization due to the high fixed costs. The duration curve show all the load that was required in the year sorted from the highest to the lowest. In Figure 2.3 for the same load level the residual demand present much lower duration, and difference is higher in the lowest load area.

Based on the duration curve is possible to obtain a preliminary estimation of the optimal power system. The upper right corner of Figure 2.3 show how the total annual capacity costs develop during the year for some technologies.

Figure 2.3: Residual system adaptation to the share of RES-E.



Source: (Nicolosi, 2011)

The base load plants has high investment cost and low variable cost (i.e. fuel and CO_2 costs) compared to peak plants. The abscissa shows the annual utilization. The crossing point of different technologies curves represent the utilization necessary to make one technology more profitable than the other one, hence these are the technology switching point. With the load and the residual load is possible to derive an assessment of the optimal power plants portfolio with and without the RES-E, (lower left part of Figure 2.3).

Another motivation to foreseen a different capacity mix of the conventional fleet is the higher variability of the load that has to be served by the conventional fleet in case of high installed capacity of VREs. The gradient of the residual load is increasing with the penetration of the intermittent RES-E. Therefore the system has to cover this situations, moreover the low flexibility of the base load plant force them to accept the negative price due to load valleys whereas more flexible power plants can avoid the negative prices.

2.3 Support Scheme for the RES

The market does not provide the optimal level of renewables in the absence of public intervention. This is due to market and regulatory failures: low levels of competition and unfair competition with other fuels, in particular subsidies for fossil fuels and nuclear energy, the incomplete internalisation of external costs (air pollution and energy security), rigid electricity system design inhibit the growth of renewable energy while such measures are necessary to correct market failures and achieve the desired level of renewables, public interventions need to be well designed and proportionate to avoid additional market distortions.(European Commission, 2013 a).

Different instruments can be used to support renewables production in the EU: The most commonly used ones are feed-in tariffs, feed-in premiums, quota obligations, tax exemptions, tenders, and investment aid (European Commission, 2013 a).

Generally the support schemes are differentiated between price-based and volume-based. In the price-based mechanism the price is set by the government, and volume of renewable develops according the cost-potential curve. The volume-driven mechanisms predetermine the price and the volume development. Many design options among the different schemes are similar, for instance is calculating the LCOE (see Appendix 1) which are used to calculate the support level in the Feed-in Premium (FiP) or in the Feed-in Tariff (FiT) schemes or to set the ceiling price in case of auction or tenders. The aim of every support scheme is to provide the right amount of support in order to trigger investments but avoid over-compensating the investors (Held A. et al., 2014).

As Germany is the research case in the work at hand, the attention will focus on the price-based schemes as the implement support mechanisms currently used belong to this class. In price-based support schemes controlling policy costs and revising and adapting support levels are two crucial issues (Held A. et al., 2014). Since the EEG 2012 (BMU, 2012) the possible support scheme that the renewable generators can choose are the FiT and the FiP mechanism, in the following are going to be presented the main characteristics of these schemes. In Germany, the burden for the RES-E support is passed on the consumers through the EEG levy the so called EEG Umlage a fixed part of which is set by the Government on a yearly basis (BMWi, 2014).

2.3.1 Feed-in Tariffs

In a feed-in tariff system the renewable power plant operators receive a fixed payment for each electricity unit in-feed in the grid. The renewable plants receive the tariff for a certain amount of years, and it is subjected to a reducing rate. Alternatively, the remuneration may be granted for capacity instead of the electricity generation in order to encourage the active participation in the power market.

Based on the regulatory framework, the transmission system operators are obliged to offer the renewable energies which have chosen to stay in the feed-in system on the electricity exchange, independent of the price (Klobasa et al. 2013). In other words the RES-E generators enjoy the “priority dispatch” therefore the TSOs are obligated to integrate each RES–E unit generated independently to the demand.

As the renewable share is increasing, the passivity of the renewable generators leads to many problems i.e. the overall flexibility of the system decrease, higher cost for balancing, higher volatility of the prices and higher frequency of negative prices.

The main experienced advantages of the FiT are its effectiveness and low risk premiums due to the stable income flow that the generators receive. In contrast whether the tariffs are not adequate set to the actual production costs there is a high risk to have low cost–effectiveness. The level of the tariffs is determined by administrative procedures. In Germany the tariff are based on the calculation of the LCOE. The tariffs are regularly reviewed by the Ministry for Environment (BMU). The tariffs are technology–specific. The tariffs are differentiated by many aspects, i.e. the type of the used energy source, the year of construction, and the installed capacity, moreover the EEG includes many other parameters.

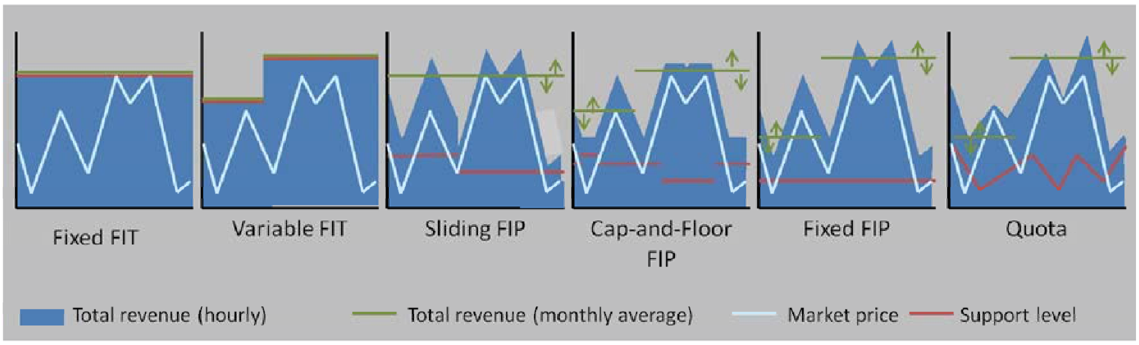
The feed-in tariff compared to other schemes i.e. the FiP is less compatible with a liberalized power market (Held A. et al., 2014).

2.3.2 Feed-in Premium

The entire section is based on (Winkler J., 2011),(Held A., et al., 2011),(Klobasa et al., 2013).

The FiP can be considered similar to the FiT, but leads to different behaviour and risk level for the RE plant operators.

Figure 2.4: Revenue for renewable generators supported with different support schemes.



Source: (Klobasa et al., 2013)

The renewable plants have to offer the generate electricity directly in the exchange market. On top of the market revenues they receive an additional payment according the particular design of the scheme. The aim of the direct marketing is to create a voluntary shut-down order in order to reduce the over-supply situations.

The main possible design options are illustrated in Figure 2.4. The premium could be fixed at one decided level (Fixed FiP), the value is normally assessed by long-term average market price forecast, and hence the generators are exposed to the short-term price fluctuations. This high risk that the generators have to bear leads to higher risk premium. Normally the support costs have a good predictability, but an unexpected increase of the electricity price could lead to a phase of over-investment and consequentially a steep increase of the policy costs.

Another option is a premium with a cap and floor. The cap and floor is fixed as the sum of revenue from the market and the premium. The aim of the cap and floor is to reduce the risk for the generators and the risk of over- and under-compensations.

The option that the German renewable generators have since 2012 is the Sliding Premium. Renewable generators can choose between the options every month. It is also possible to sell a percentage of the generated electricity under the premium option while the remaining share receives the fixed tariff. The plant operators needs to inform the grid operator in advance about these percentages.

The German Market Premium Model

The German Market Premium Model is a sliding premium model. The premium change according the price development therefore is a dynamic mechanism. Although the premium is changing the level of the support is stable. In this way the generators are not completely exposed the market price fluctuation, but the risk is higher than under the FiT.

The premium is calculated ex post on a monthly basis. It is based on the difference between the feed-in tariff and the technology-specific monthly market value. The market value of a RES-E technology assesses the possible marketing revenues for the sold electricity by the technology on the power market. The market value is calculated as the income streams divided by the total generation of a certain period (Equation 3 at page 49). Coupling the premium to the monthly average of the market price seen by the generator eliminates the risk of the general market price development but still gives incentive to react to the hourly price development.

In the German market premium is choose the market value instead of the easier market price because the fluctuating generators do not have the same possibility of the thermal generator to adjust their generation just on the economic incentives but they have to face even the uncertainness of the weather condition, and with high share of VRE is expected that the price in the hour with high in-feed of renewables will drop due to the so called merit-order effect.

Relating the market value of a variable renewable source to the average market price, the so called market value factor[7] (MVF), is useful for assess the profitability of a variable renewable energy source to a constant one.

The generators that choose the market premium scheme receive also a technology-specific management premium meant to cover the additional costs of the direct market, i.e. IT-systems, personnel, forecast costs etc.

The output of the VRE, is determined by the weather, hence their generation is concentrate in some period of the year. With the growth of variable renewable higher frequency of surplus situations with negative price can be expected in the near future. Create a merit-order of voluntary RES-E shutdowns is one of the intentions of the market premium model. The aim is to reduce the negative prices and prevent the disconnecting or switching-off of the thermal plants for a short period, that could cause high costs and also technical difficulties (Klobasa et al., 2013).

[7] The MVF is shown in Equation 4 at page 26.

3 Methodology

In this section are presented in detail all the taken assumption for the input data and the model. Furthermore is explain in detail the used model, how it was build and how where retrieved the input data. Moreover is given a detail explanation of the considered scenario.

3.1 Scenarios overview

The design of a support mechanism that require to the renewable operators to be active in the market influences the way in which renewables participate in electricity market. If they have the grid priority then no active participation is required, whereas if they are part of the merit-order curve, as the conventional plants, then the support influence directly their bidding behaviour.

In the work at hand, four different policy designs are assessed. The first one, which will be labelled *Grid Operator Trader* (GOT), aims to simulate the grid priority of the renewable generators under the feed-in tariff, where the RES-E generation is dispatched by the TSOs. In this scheme the renewables are offered in the power market at the minimum price, that is –150 €/MWh, and therefore they are largely dispatched.

The so called *Feed-in Tariff policy design* (FIT) aims to simulate a situation where the generators earn completely the tariff established in the EEGs[8] but they have to participate actively in the market. This scheme is technically a fixed premium.

The support mechanism labelled *Sliding Premium* (SP) aims to simulate the German Market Premium model (see Section 2.3). The renewable generators participate actively in the market and they receive a variable premium on top of the market revenues.

The last modelled design aims to simulate the renewable generators that participate at the power market and they do not receive any support. In this scheme the renewable

[8] For the huge number of tariffs in the EEGs is used a simplify parameter labelled *Feed-in Tariff value* (see Section 3.6).

generators bid at their marginal costs (see Section 3.5). This design option will be label *Open Market* (OM).

The policies are tested on four different background situations. Hence were run sixteen simulations, see Table 3.1. The aim was to simulate the impact of the bidding behaviour on the German Spot Market in 2020 in 2030 with two different reserve market designs. To do this, were analyzed the generation and capacity development of the renewables (see Section 3.3) and the conventional fleet (see Section 3.4), were assumed $CO_{2,}$ fuel, and biofuel prices (see Sections 3.7, 3.8, and 3.5.1 for the complete explanation) for 2020 and 2030.

About the reserve market were considered two situations. The first one, that will be labelled *not flexible*[9], simulates the current situation of the reserve market. The generators in the reserve market, have to be online and operating in order to be able to adequate their production for balance short-term demand fluctuation or blackout and to ensure adequate system reliability. So far, in the regulatory framework, is still missing to enable fluctuating REs to participate in the reserve market. The steam-flow thermal power plants[10] have technically constraints (that are simulated in the model) regarding the minimum load. The minimum load is roughly 40% of the nominal load; hence the thermal power stations in the reserve market have to offer 40% of their nominal power in the spot market to a very low price to ensure that they can be online (in the simulation they bid at the "minimum price", hence they are always dispatched).

The other scenario is named *flexible*, in this scenario the base load plants bid in the power market at their variable costs, and no capacity is contracted from the wholesale market. This scenario aims to simulate a hypothetical situation where the RE generators can be in the reserve market. The scenarios were label like this because of the different degree of freedom that they have respect the RES-E.

9 Not flexible for the RES-E.

10 Also named base load plants.

In this section, is explain in detail the assumption use on the input data, which data were use for the simulation, and from where they were retrieved or how they were extrapolated. Is also presented the basic structure of the model and the improvements on it in order to run these simulations. The scenarios can be summarized as follows in Table 3.1.

Table 3.1: Scenarios Overview.

<table>
<tr><th>Simulation´s base year</th><th colspan="2">Scenario Name</th><th>RES with grid priority</th><th>RES bid price</th><th>Share of RES-E</th><th>Convenetional Fleet</th><th>CO2 price</th><th>Biofuel price</th><th>Base Year for Weather Conditions</th></tr>
<tr><td rowspan="8">2020</td><td rowspan="4">Not flexible</td><td>GOT</td><td>Yes</td><td>-150 €/MWh</td><td rowspan="8">35%</td><td rowspan="8">Mostly base load plants</td><td colspan="2" rowspan="8">Lower</td><td rowspan="16">2008</td></tr>
<tr><td>FIT</td><td>No, direct market</td><td>FiT value</td></tr>
<tr><td>SP</td><td>No, direct market</td><td>Premium</td></tr>
<tr><td>OM</td><td>No, direct market</td><td>Marginal costs</td></tr>
<tr><td rowspan="4">Flexible</td><td>GOT</td><td>Yes</td><td>-150 €/MWh</td></tr>
<tr><td>FIT</td><td>No, direct market</td><td>FiT value</td></tr>
<tr><td>SP</td><td>No, direct market</td><td>Premium</td></tr>
<tr><td>OM</td><td>No, direct market</td><td>Marginal costs</td></tr>
<tr><td rowspan="8">2030</td><td rowspan="4">Not flexible</td><td>GOT</td><td>Yes</td><td>-150 €/MWh</td><td rowspan="8">50%</td><td rowspan="8">Mostly mid-pick plants</td><td colspan="2" rowspan="8">Higher</td></tr>
<tr><td>FIT</td><td>No, direct market</td><td>FiT value</td></tr>
<tr><td>SP</td><td>No, direct market</td><td>Premium</td></tr>
<tr><td>OM</td><td>No, direct market</td><td>Marginal costs</td></tr>
<tr><td rowspan="4">Flexible</td><td>GOT</td><td>Yes</td><td>-150 €/MWh</td></tr>
<tr><td>FIT</td><td>No, direct market</td><td>FiT value</td></tr>
<tr><td>SP</td><td>No, direct market</td><td>Premium</td></tr>
<tr><td>OM</td><td>No, direct market</td><td>Marginal costs</td></tr>
</table>

3.2 The PowerACE model

3.2.1 The base version

Since PowerACE permits many different possible settings in the following the attention is mainly focuses on the settings that were used for the simulations.

The current version of PowerACE cluster system seeks to simulate the central processes regarding the trading, generation and distribution of electricity in Europe. The markets represented in the model include the day-ahead and reserve markets, but it also deals with other aspects of the power market, such as electric mobility and the retail market. Furthermore embedded in the PowerACE cluster system there is a capacity optimization module.

The base version of PowerACE focuses on an agent-based power market model of the German power markets. A detailed description of the model is given by (Sensfuß F., 2007), a brief presentation of the optimization model is given in the following, whereas a complete description is given by (Pfluger B., 2013). The first version of the model was developed in cooperation between Fraunhofer Institute for Systems and Innovation Research ISI, the University of Karlsruhe and the University of Mannheim and was sponsored by the “Volkswagen Stiftung".

PowerACE seeks to simulate the markets in several modules, which are implemented in the programming language JAVA[11]. The core of the model focuses on the matching of demand and supply on the spot and reserve markets. A simplified visualization of the structure of the PowerACE is depicted in Figure 3.1.

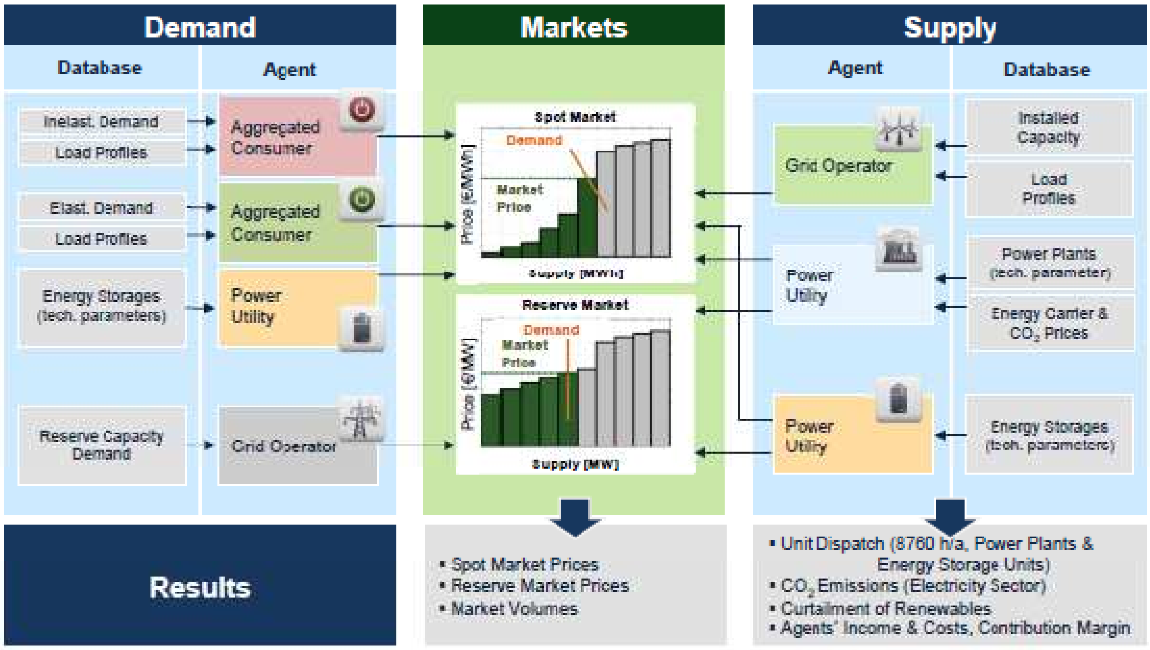
Important actors of the electricity market are represented by agents in the model. The agents have a restricted access to information on the market, which they use to act within their means. These agents include for example utilities selling electricity produced by thermal units and storage devices and an aggregate agent is trading electricity from renewable sources. The agent that trade the renewable capacity represent the TSO

11 Java is an open source programme., available at http://www.java.com.

that under the feed-in tariff support scheme was obligated to dispatch completely the renewable generation. On the demand side, an aggregated supplier bids a demand profile into the market.

The model has a high level of technical detail and market rules. The generation side of the model includes generation from conventional power plants and RES, as well as production from pumped storage hydro power plants.

Figure 3.1:Simplified structure of the PowerACE structure, before the changes.



Source: (Pfluger B., 2013)

Although the model is able to calculates hourly electricity market prices for 27 EU countries based on the core clearing mechanism of the cluster, these simulations where carried out just for Germany.

The module proceed as follow:

1. Storage facilities optimize their bids based on forecasted prices.

2. If the interconnection with the reserve is established, than plants are contracted for the balancing markets.

3. The bidding for the regular day-ahead market takes place.

In the simulations presented in this dissertation, the plants bid according to their variable costs (i.e. fuel and CO_2 costs), although in PowerACE is also possible to include into the conventional bids also cycling costs and markups in scarcity situations.

Whether in the simulation is established the setting for interconnect spot and reserve markets than the plants contracted in the balancing market bid a very low price into the day-ahead market forty percent of their available capacity in order to simulate their obligation to be online.

All data used by the model are stored in MySQL[12] databases located on a server at the Fraunhofer ISI. The databases store input data, and the general model control parameters. In the input data is included e.g. historic weather data for electricity production from renewables as well as a historical hourly demand profile and conventional fleet technical specific are included as input data into the model.

Interconnector capacities between countries are part of the model while national grids are not represented. In the used model version, the trading between the countries is considered exogenous. Therefore also the import and export of the electricity is considered as input, and is stored as well in the database. The international trade is represented as bids into the market. The imports are supply bid at the minimum price, whereas the exports are demands bids at the maximum bid price.

The conventional supply database is plant-specific, thus every plant has its own technical parameters. Whereas the generation of the renewable is divided just in aggregate technology-specific categories, for instance on shore wind or Photovoltaic (PV), therefore there is no distinction due to different locations, techniques such as higher towers. The curtailment of the renewables is possible only at times when renewable production on its own is higher than the domestic demand plus possible exports.

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12 MySQL is a relational database management system. The program is open source and available on www.mysql.com .

3.2.2 Changes in the PowerACE model

Since the introduction of the market premium model, with the EEG 2012, more than 80% of the wind power have switched to this form of marketing, 39% of the biomass capacity is directly market and almost 7% of the PV (Klobasa et al., 2013). Therefore the part regarding the renewable trading of PowerACE had to be updated to follow the market changes.

The renewable generation was completely traded from the class "`GridOperatorTrader`" (GOT). The entire renewable volume was bid into the market at the minimum price (-150 €/MWh). The GOT seeks to simulate the grid priority of the renewable energies under the fixed feed-in tariff. The renewable generation profile is based on historical data normalized on the total annual generation. The curtailment of the renewables is possible only at times when renewable production on its own is higher than the domestic demand plus possible exports.

The code was modified towards to simulate the German market premium; therefore both volume and price of the renewable trading system were re-designed.

Nonetheless this dissertation is about Germany, the new part of the code was implemented for all Europe as the rest of the code. The core of the renewable trading algorithm is in the class "`RenewableAgentPrice`" where the method "`callForBidsSpot`" (Appendix 12) go through the regions and the renewable technologies in the scenario for generate the hourly bid with the method "`generateHBid`" (Appendix 16).

Every region can have different support mechanisms. The type of the support scheme is a field of the class `Region`, and it can be set in the database. The "`callForBidsSpot`" method go through the regions, renewable technologies in that region and the *year of construction*. "`generateHBid`" is a switch method that according the support scheme of the region call the corresponding method for generate the bid. In this way the code can be easily adapt, i.e. to new support mechanisms, with just adding a new methods, and adapting "`generateHBid`". So far the implemented support schemes simulates the German market premium that will be called in the following SP (Appendix 11), a fixed premium in which the premium is the feed-in tariff (FIT, Appendix 10), and the direct market (OM, Appendix 9).

Appendix 9In a competitive electricity market, generators are incentivised to offer at their marginal production costs. If they bid at a higher price, they are in danger of not being dispatched. In case of a bid below the marginal costs, generators are dispatched but not able to cover their marginal costs. Since the operators receive the premium just if they are dispatched the premium represents a part of their opportunity costs. Therefore in the SP scheme they bid into the market their marginal cost minus the *expected* premium (see the PowerACE algorithm for the market premium in Appendix 11), whereas in the OM they bid at their marginal costs (see section 3.5), and under the FIT the feed-in tariff value (see section 3.6).

In real market the market premiums are calculated every months by TSOs as the feed-in tariff minus the market value of the technology. As the renewable cannot know the development of the market prices they have to forecast their MV. In the model this is simulated by using the yearly price forecast that is use also by the pump storages. The forecast in the PowerACE model is made as a run of the model without pump storages and the renewables are traded by the GOT. Then the renewable agents every month calculates their MV with the annual forecast.

The feed-in tariff value, for the same technology, changes with the year of construction of the power plant and with other technology specifics, i.e. the installed capacity. In light of the variability of the feed-in tariff (see section 3.6), assume just a single bid price per technology was considered an unsafe assumption, thus was decide to split the total generation by the year of construction. Were not use other sub-categories because the EEGs have many technology-specific parameters that were not possible to integrate in the code, and was considered not really useful in term of quantitative changes on the results. For a complete explanation how were obtained the FIT value per year of construction see section 3.6.

The total generation is divided into different year of construction according the installed capacity per year, the algorithm that split the generation is show in Appendix 15. The generation due to the capacity installed in a generic year is obtained as total generation times the installed capacity in that year dived the total installed capacity.

The installed capacity per year is indirectly generated in the code from the total installed capacity profile calculated in section 3.3 that are used as input data. The algorithms that calculate the installed capacity per year are show in Appendix 13 and Appendix 14.

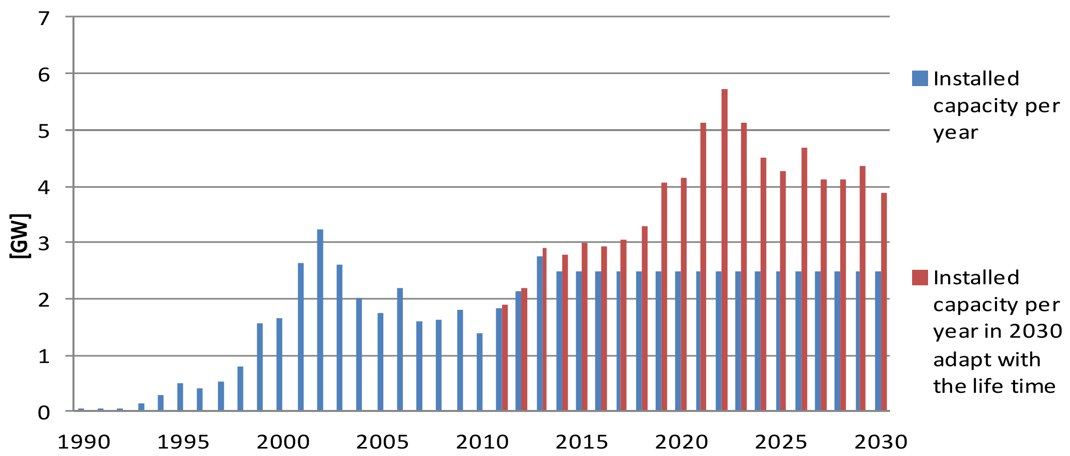
The installed capacity of a generic year is obtained as the total capacity installed that year minus the total installed capacity of the year before. In case of a reduction of the total installed capacity than the value of the installed capacity per year should be negative.

The capacity is readapted following the principle of “first in-first out”, therefore in the years where the capacity decrease the installed capacity is assumed to be zero, and the reduction of the capacity is subtracted to the previous year starting from the first one. Afterwards, the capacity is adapted with the assumed life time for the power plants, as usual, is assumed that the RES-E plants have a life time of 20 years.

The installed capacity per year older than 20 year from the base year of the simulation is shift of 20 year. This method seeks to simulate the replacement of the power plants. Is considered important to remember that with this algorithms the total installed capacity and the total generation do not change, the only variations are due the numerical errors because of the floating points.

In Figure 3.2 is shown the installed capacity per year, and the installed capacity per year readapt to the assumed life time of 20 years for the on shore wind. The total installed capacity per year profile for the on shore wind is shown in Figure 3.4.

Figure 3.2 : Example of how works the algorithm for generate the installed capacity per year.



Source: Own illustration.

In summary the bid from the renewable includes a price and a volume.

The price is influenced by the support mechanism. So far in the model where implement SP, FIT and OM.

The Volume is split in sub-categories of the year of construction, the division is made according the installed capacity per year.

Compared to the previous version the model is much more flexible. For instance, with eight different renewable technology there was just one bid price, whereas now is possible to have 160 bid with different price and volume.

3.3 Scenario for capacity and Generation

For run the simulation of 2020 and 2030 was need to generate a scenario about the growing of the renewable. For do that were analyzed the historical data series, retrieved from (AGEE stat, 2014), in order to extrapolate a meaningful growing scenario, furthermore were followed the guidelines of the Renewable Energy Sources Act (EEG) 2014 (BMWi, 2014). The Renewable Energy Sources Act (Erneuerbare Energien Gesetz – EEG) promotes, in Germany, the generation of electricity using renewable energy sources. The purpose is to achieve the share of renewable energy sources in electricity supply to at least:

1. 35 percent by no later than 2020;
2. 50 percent by no later than 2030;
3. 65 percent by no later than 2040; and
4. 80 percent by no later than 2050;

The transformation of the energy supply system towards renewables is a challenge, especially for a thermal-based system, as is the German electricity supply system (see Section 1.2). For help the sustainable and cost effective growing of the renewable side of the electricity power supply, the EEG provides detailed figures of the planned increase of the installed capacity for the different renewable technologies. These growth targets are an innovation for the German support scheme. These are called “Expansion corridors and Breathing Caps”, according the EEG, the targets are summaries as follow:

1. The On shore wind capacity has a annual net growth target of 2500 Mega Watt (MW);
2. The Off shore wind capacity target in 2020 is 6.5 Giga Watt (GW) and 15 GW by 2030;
3. The solar power a gross annual growth corridors target of 2500 MW, with a cap 52 GW;
4. The Biomass a gross annual growth corridor of 100 MW;

For hydro power and geothermal power there are no growth corridors, their potential is mostly exploited, and furthermore they represent a small part of the yearly generation were assumed that no new capacity will installed.

The data from (AGEE stat, 2014) were used as historical series for the capacity of the renewable sources. The renewable technologies that were simulated in the model are:

1. Biomass

2. Biogas
3. Hydro power
4. Geothermal power
5. On shore wind
6. Off shore wind
7. Photovoltaic (PV)
8. Photovoltaic on the roof (PVR)

For the calculation of the installed capacity were taken into account even the hydro storages nonetheless they represent a very small part of the installed capacity. The used report, (AGEE stat, 2014), do not follow the same categorization of the RES-E.

The category of *Biomass*, in this work, correspond to biomass, biogas, bioliquid and waste in (AGEE stat, 2014) categorization, whereas *Biogas* correspond to landfill gas, sewage gas, mine gas.

The reason for this choice were the similar cost more than the physical similarities. The solar technologies, in the used historical database, are all under the category Photovoltaic. For split the class into PV and PVR were used historical data of the installed capacity in Germany retrieved from the transmission system operator's (TSO) web sites[13].

The assumed dividing line between PV and PVR is 1000 MW of installed capacity. The historical data analysis is shown in Figure 3.3; from 2013 to 2030 their shares are assumed to keep constant.

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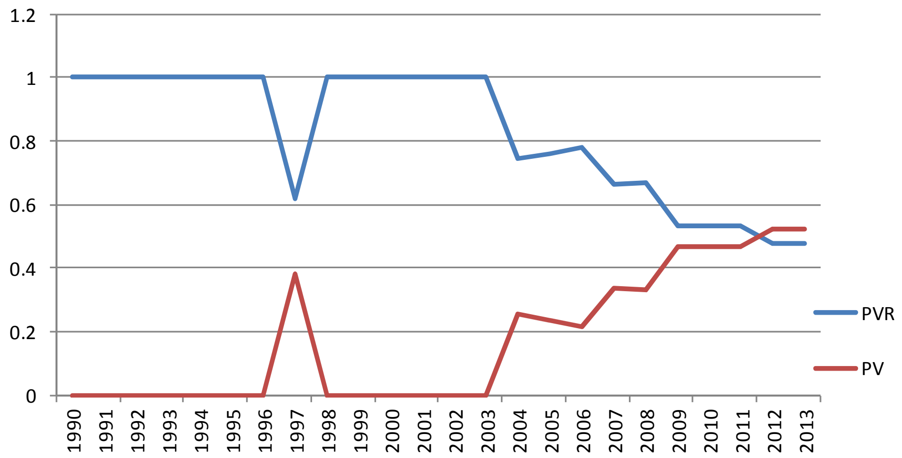
[13] The data can be retrieved in the TSO´s websites (TransnetBW, 2012) (TenneT, 2012) (Aprion, 2012) (50Hertz, 2012).

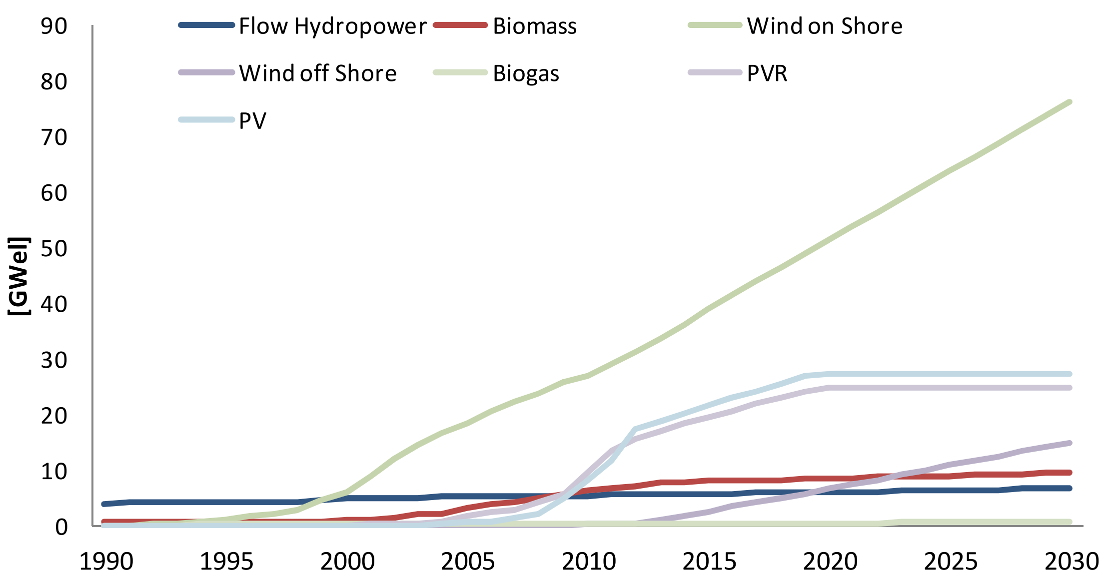
Figure 3.3: Share of PV and PVR in Germany from 1990-2013.



Source: Own illustration, data source see footnote 13 at page 36.

The EEG growth corridor of the biomass is spilt into *Biomass* and *Biogas* according their proportion of installed capacity in 2013, which is 51percent of *Biomass* on the total. The historical data, the growth corridors, and the assumptions enable to develop a capacity scenario, shown in Figure 3.4, for the precise installed per year see Appendix 3. For reasons of clarity, geothermal and hydro storages installed capacities are leaving out from Figure 3.4; although they were taking into consideration for the calculations.

Figure 3.4: Installed renewable capacity scenario.



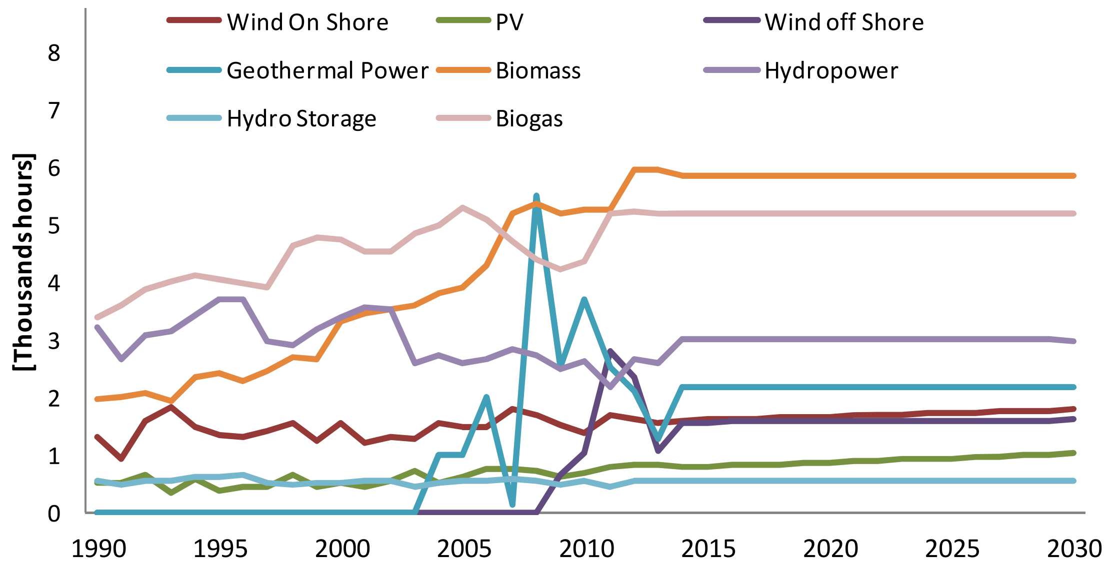
Source: Own illustration. Based on (AGEE stat, 2014) and (BMWi, 2014)

For asses the future generation from RES-E in 2020 and 2030 were assumed that the total electrical gross consumption will keep constant from the historical of 2013 up to 2030, the used value is 600630 Giga Watt Hours (GWh)(retrieved from (AGEE stat, 2014)). Nonetheless the EEG aims to improve even the efficiency of the overall electrical system this assumption were considered safer and it even lead to an easier comparison among the scenarios.

As the EEG refer just to the total share of the RES-E and to the capacity caps and corridors, for establish the forecasted generation scenario, an overall analysis of the historical full load hours (FLH) of the RES-E was carried out (for the full load hours overview see Figure 3.5). The full load hours of a power plant are just the ratio between dispatched generation and installed capacity. The full load hours represents the number of hours that an *ideal power plant*[14], with the same capacity, needs to run for produce the same generation. The historical full load hours were calculated with the data from (AGEE stat, 2014). For the solar technologies and the on shore wind is assume that the FLH will grow according the historical trend, the reason is the high possibility that these technologies will have technological improvements. For the high variability of the historical data for the off shore wind and the geothermal power, were chose to use the average of the historical full load hours, for the hydro power, pump storage, and biogas the FLH are keep constants up to 2030, the utilization of the biomass were calculated as the different needed generation for reach the target. The resulting FLH of the biomass are roughly in line with the current value (see Figure 3.5), which are an index for asses the validity of the considered assumption.

14 Ideal means that the power plant has no losses in the conversion of energy and it does not need to stop for the maintenance.

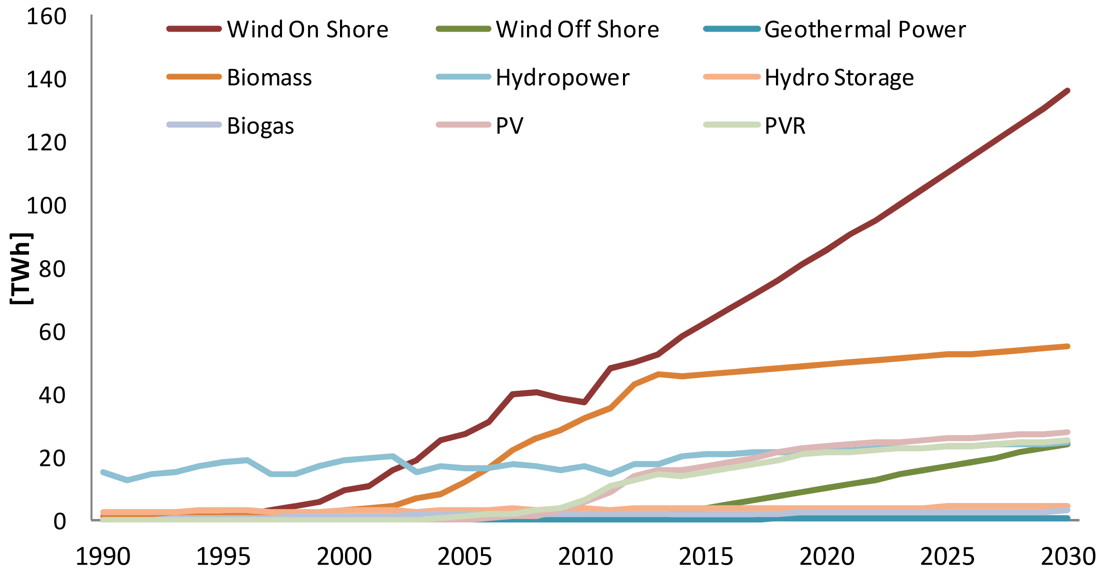
Figure 3.5: Full load hours of the RES-E



Source: Own illustration. Based on (AGEE stat, 2014) and (BMWi, 2014)

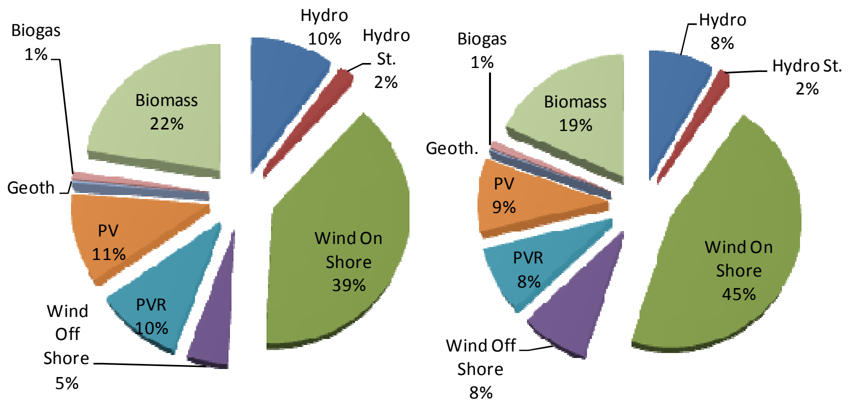
Finally, the forecasted generation was obtained as full load hours times the capacity. In Figure 3.7, is shown the overall renewable generation mixes in 2020 and 2030. For the forecasted development of the renewable generation see Figure 3.6, for the used data in the simulation see Appendix 4

Figure 3.6: Renewable generation scenario.



Source: Own illustration. Based on (AGEE stat, 2014) and (BMWi, 2014).

Figure 3.7: Renewable generation mix for 2020 (left) and 2030 (right).



Source: Own illustration. Based on (AGEE stat, 2014) and (BMWi, 2014).

3.4 Residual load (the optimization model)

PowerACE is a powerful model for the analysis of the electricity sector. It can be configured as agentbased simulation tool or as tool for the optimization of electricity systems in Europe. In this study is used in both the configurations, it is used as optimization tool to calculate the residual conventional system with the considered development of the renewable in section 3.3. A detailed description of the optimization model is given by (Pfluger B., 2013).

The optimization model seeks to minimize summed system cost. “Besides the central function to find a least cost system additional constraints can be integrated in the analysis. The most important constraint is that demand and supply have to be matched in any region of the model for every single hour of the target years which are modelled by 8760 hours. Other important constraints are CO_2 limits, annual national self supply rates and minimum or maximum conditions for single parameters such as net transfer capacity over the entire time period with perfect foresight. Perfect foresight is a technical term for the fact that the model optimizes the system with full information on all data required at any time step and on all the consequences of the decisions on any time step. Capital costs of all investment options are included as annuities”(Senfuss F., Pfluger B., 2014). Investment options available to the model include just power plants, interconnectors for electricity transport and storage facilities.

“The objective function which determines the central target to develop an electricity system with the lowest cost possible within the given framework conditions, also includes the cost of hourly dispatch such as fuel cost or variable operation and maintenance cost”(Senfuss F., Pfluger B., 2014).

As input data or the model were used the PowerACE database of power plants and the renewable capacity calculated in the previous section. The model results gives the optimize system for 2020 and 2030. The result from the model are given in Table 3.2.

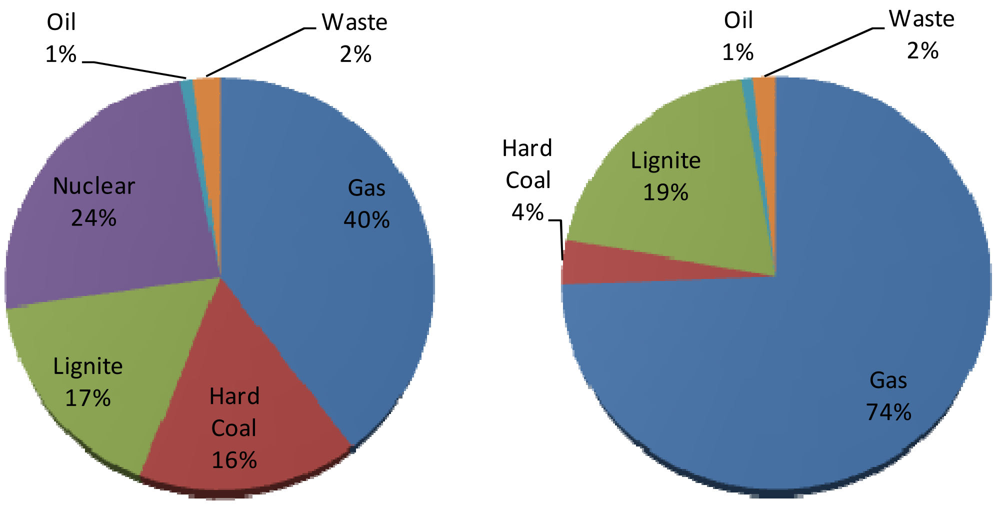
Table 3.2: Simplified power plants portfolio.

	2020	**2030**
	[MW]	[MW]
Gas	33,117	59,048
Hard Coal	13,464	2,757
Lignite	13,923	15,416
Nuclear	20,242	-
Oil	857	735
Waste	1,734	1,472

The results could be foreseen in light of the theoretical framework given in section 2.2.3. The capacity mix is substantially changed in favour of the gas technology.

The optimal scenario does not reduce the total installed capacity and there is high share of peak plants, because of the reduction on the utilization of the conventional fleet.

Figure 3.8: Capacity mix of the conventional plants.



Source: Database power plants PowerACE and Optimization model.

3.5 The Marginal costs of the Renewable

As usual in this kind of simulation (for instance see (Hirth, 2013)) the marginal costs of the RES-E, a part of the renewables fired technologies, is set to zero. A better choice could be to use the long-term levelized cost of energy (LCOE), see Appendix 1 for the definition, instead of the marginal cost but the analysis of the LCOE is not an aims of the work at hand.

3.5.1 Biofuel prices

The biogas and biomass power plant operators has to pay the fuel for run their power plant. Therefore for these technologies the fuel cost is set as marginal cost. The forecast biofuel prices are based on (Held A., et al., 2011). In the simulations were used for Biogas and Biomass it was used the average fuel prices in Table 3.3.

Table 3.3: Biofuel ´s prices

Fuel Price	**2020**	**2030**
	[€/MWh]	[€/MWh]
Biowaste	-5.40	-5.52
Biogas	13.07	11.05
Solid Biomass	17.19	17.80
Average	**11.01**	**11.15**

Source: Based on (Held A., et al., 2011).

3.6 The Feed-In-Tariff values

For simulate the bidding behavior of the RES-E generators under the FIT or SP schemes is necessary to simulate the tariffs and the premiums that the generators receive in the direct market (for the complete explanation see Sections 0 and 3.2).

The tariffs that the generators get for the dispatched energy are established in the EEGs[15]. The tariffs that get the generators is technology-specific, therefore it could be seen as a function of many factors. It basically depends on: the year of installation, type of energy source, and the installed capacity. In the work at hand the chosen categories were: the energy source type and the year of installation. The resulting value in the following will be labeled as *FiT value.*

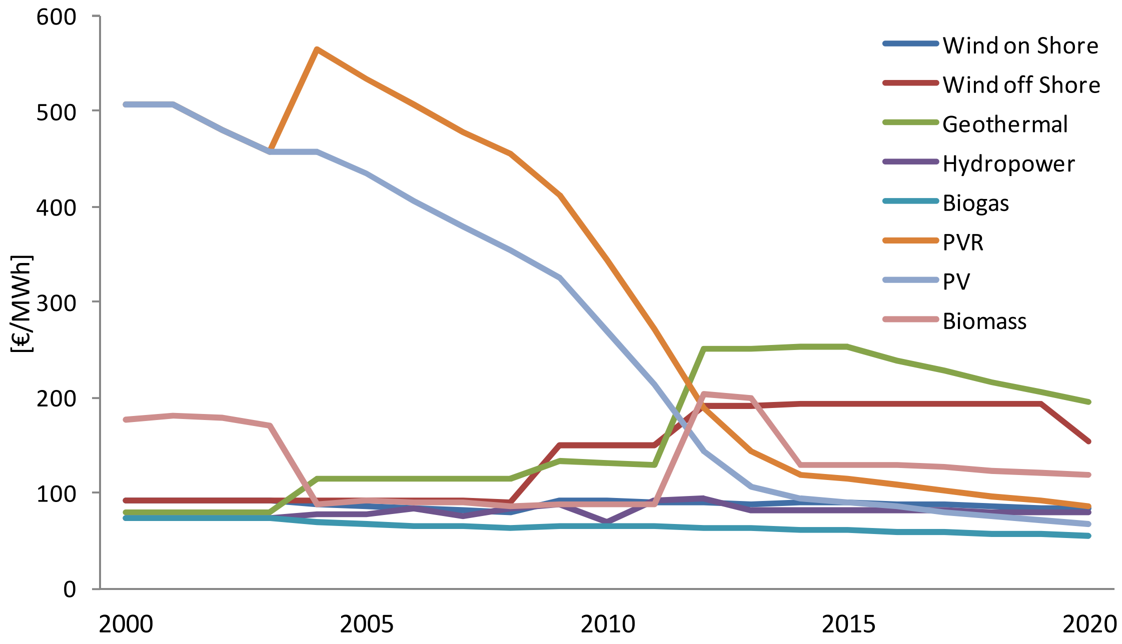
For calculate the *FiT value* were used all the tariff from the EEGs[15]; of all the tariff[16] of the same year and the same technologies were calculated the weighted average on the historical installed capacity. The share of installed capacity where calculated for every technology based on the EEGs versions, the data were retrieved from the TSOs web sites (the data are available in TSOs web sites (50Hertz, 2012), (Aprion, 2012), (TenneT, 2012), (TransnetBW, 2012)). Nonetheless the data series of the installed capacity were

[15] The EEGs can be retrieved in (BMU, 2000) (BMU, 2004), (BMU, 2009) (BMU, 2012) (BMWi, 2014)

[16] The EEG of 2000 still uses the deutsche mark, the used conversion rate is provided by the European Central Bank, it can be find in (European Centrl Bank, 1998).

not complete, the FiT value were calculated. The overview is in Figure 3.9 the data used in the model are collected in Appendix 2 (see in footnote 15 page 43)

Figure 3.9: Feed-In-Tariff value curves.



Source: Own research, data source: the installed capacity data were retrieved from the TSOs web sites ((50Hertz, 2012), (Aprion, 2012), (TenneT, 2012), (TransnetBW, 2012)). The EEGs can be retrieved in(BMU, 2000), (BMU, 2004), (BMU, 2009), (BMU, 2012), (BMWi, 2014).

3.7 The CO_2 Price

The assume carbon dioxide (CO2) price is shown in Table 3.4.

Table 3.4: Assumed CO_2 prices.

	CO_2 prices
	[€ /t]
2020	19.95
2030	39.89

3.8 Conventional fuels cost

The assumed conventional fuel cost for the simulations are collected in Table 3.5

Table 3.5: Conventional fuel costs overview.

	2020	2030
	[€/MWh]	[€/MWh]
Gas	29	31
Hard Coal	14	16
Lignite	4	4
Nuclear	8	-
Oil	48	46
Waste	0	0

4 Results

4.1 Introduction

The model results are presented in this section, whereas in Section 5 the scenarios are compared and an overall interpretation of the results is given.

The results are divided into Dispatched Generation presenting the conventional and renewable generation mix for all the scenarios. After that is going to be presented the Penetration ratio and Capacity Factor for the considered scenarios. For reasons of clarity, the results are divided into the year of the simulation and type of flexibility in the reserve market. This kind of division leads to an easier comparison among the scenarios with same base year and flexibility but different bidding behaviour. In Section 5, a comprehensive analysis is presented.

The parameters that were taken into consideration for every scenario could be categorized as *general market parameters*, and parameters more focus on the RE, which are labeled in the following as *RE parameters*

As *General Market Parameters* is presented the annual and monthly *average energy price*[17] (Equation 1) is defined as the temporal average of the spot market hourly price (p_h) The considered temporal horizons are the year or the month, so the summation in Equation 1 is extended either to the hours in the year or to the hours in the month (N).

Equation 1: Average Market Price.

$$\overline{p} = \frac{\sum_{h=0}^{h=N} p_h}{N} \quad [€/\text{MWh}]$$

As a metric for comparing the variability of the electricity price during the year the *minimum* and *maximum hourly prices* are used, that occurred in the yearly simulation and the *standard deviation* (σ) is calculated as shown in Equation 2.

17 The average market price has been also call system base price, time-weighted average wholesale day-ahead price, or electricity price.

Equation 2: Standard Deviation of prices.

$$\sigma = \sqrt{\frac{\sum_{h=0}^{h=N}(p_h - \overline{p})^2}{N-1}} \quad [€/\mathrm{MWh}]$$

In the result is also presented the *number of hours where the simulation clearing price is negative* (ζ) .

The RE parameters are grouped by partially dispatchable[18] and dispatchable technologies. The parameters are divided because there are important economic differences between dispatchable and VRE technology. The dispatchable generators can adjust their generation on the economic incentives, whereas the VREs are subjected to the weather conditions. Biofuel-fired plants, hydro power, and geothermal power are usually called dispatchable renewable energy sources. For the biofuel and the geothermal is understandable why the input is considerable constant. For the hydro power the output is dependent on the seasonal water level in the rivers. However, an analysis of published data suggests that the market value of the hydro power can be assumed constant (Klobasa et al., 2013). Whereas solar and wind are considered variable in terms of output.

As *RE parameters* the *market value* (MV) and *market value factor* (MVF) are used. In the work at hand, the market value of the renewable energy (RE) is defined as the monthly/yearly average revenue that the renewable generators can earn from the market. Moreover, under perfect and complete markets, the market value is equal to the marginal economic value that the RESs have for the society. Hence it is the market value that should be used for welfare, cost-benefit, or competitiveness analyses(Hirth 2013). So the market value and the market value factor can be considered good metrics to compare the profitability in the market of the renewable energy. The formal definition of the market value, that we use, is exactly the same as in the German market premium

[18] Partially dispatchable renewable have been also be termed intermittent, fluctuating, variable renewable energy (VRE), or not-dispatchable.

model[19]. The market value is calculated as the income that the generators earns from the market divided by the total generation dispatched. The MV is formally defined in the Equation 3.

Equation 3: Market Value

$$MV = \frac{\sum_{h=0}^{N} p_h \cdot g_h}{\sum_{h=0}^{h=N} g_h} \quad [€/\mathrm{MWh}]$$

The MVF is determined by dividing the market value by the average market price. “[...] the value factor is a metric for the valence of electricity with a certain time profile relative to a flat profile. The wind value factor compares the value of actual wind power with varying winds with its value if winds were invariant” (Hirth 2013).

Equation 4: Market Value Factor

$$MVF = \frac{MV}{\bar{p}} \quad [-]$$

Source: (Klobasa et al. 2013).

4.2 Dispatched Generation

All the scenarios assume the same total and hourly distribution of the demand during the year. The availability for the variable renewable energy plants, as solar and wind, depends mostly on the weather conditions. In the model, the possibility to generate for the VREs is simulated by using feed-in historical data series normalized with respect to the total annual generation. All the scenarios use the same base year for simulating the weather conditions, therefore the VREs have the same hourly generation profile but scenarios with different base years have different total generation, due to the assumed different total installed capacity (see Section 3).

[19] (Klobasa et al. 2013) provides an analysis of the German feed-in premium model.

The differences among the scenarios could be summarized like this:

- When compared to the 2020 scenarios the scenarios with *2030* as base year have:
    - Higher *RES-E installed capacity* (see Section 3.3);
    - Different *mix of the RES-E* (see Section 3.3);
    - Different *mix of the conventional fleet* (see Figure 3.8);
    - Higher *CO_2 price* (see Table 3.4);
    - Higher *fuel prices* (see Table 3.5);

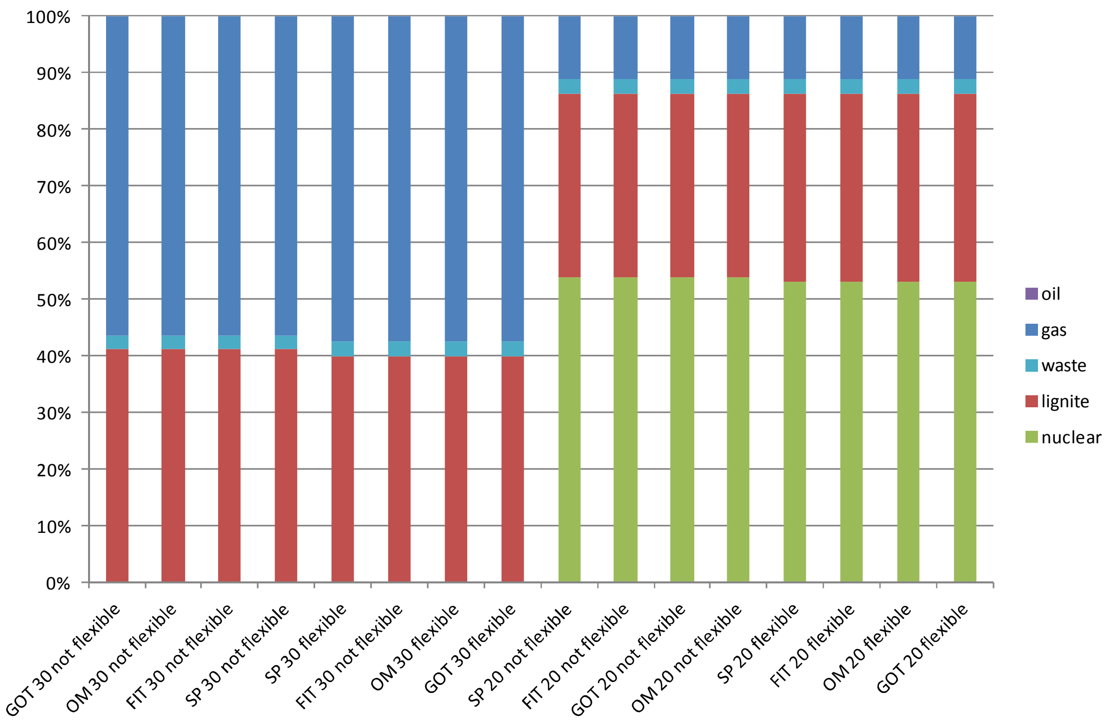
  In the scenarios labelled as:

    - *Not flexible* the plants that take part in the primary and secondary reserve sell 40% of their capacity in the spot market at the minimum price, and the rest of their available capacity at the variable cost;

      Flexible all the conventional plants bid at their variable cost;

- The *bid price of the RE generators* changes according their support policy (for the detailed explanation see Section 3). The renewable capacity in the scenarios is labelled as:
    - *GOT*: is sold at the minimum price (-150 €/MWh);
    - *FiT*: according to the FiT value;
    - *SP*: according to the premium that the generators expect to receive (the premium is calculated as FiT value minus the MV and the fuel cost);
    - *OM*: at the variable cost;

Figure 4.1: Annual generation mix for the conventional technologies.

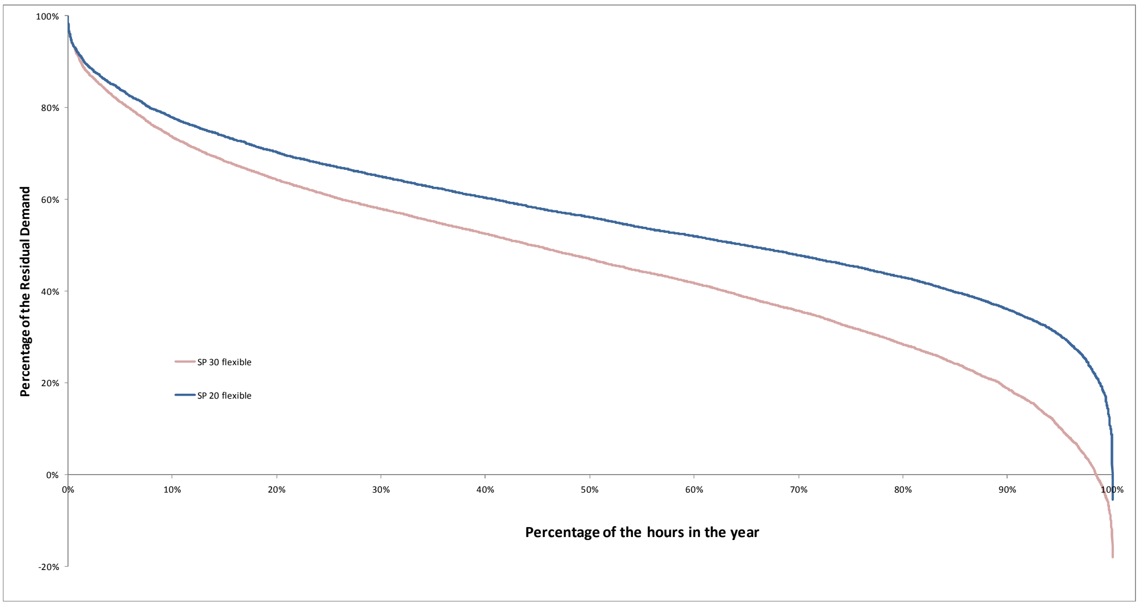


Source: Own Calculation. The data are from the PowerACE model.

Figure 4.1 shows the annual generation mixes of the conventional technologies. In 2020 the majority of the conventional annual generation is produced by the cheap technologies (nuclear, waste, lignite, for their fuel prices see Table 3.5), whereas in 2030 the biggest part of the conventional generation is served by gas plants. The subtle difference on the dispatched lignite between flexible and not flexible scenarios in 2030 is due to the must run capacity. The higher generation percentage of gas plants[20] in 2030 can be explained in light of Figure 4.2 and with the assumed conventional capacity mix see Figure 3.8.

20 The oil and gas plants are usually labelled as *pick plants* because, they have higher variable costs, and better technical possibility to ramp-up and down, compare to the *base load plants* that are normally steam stream plants. Hence the pick plants are bring online when there is high residual demand.

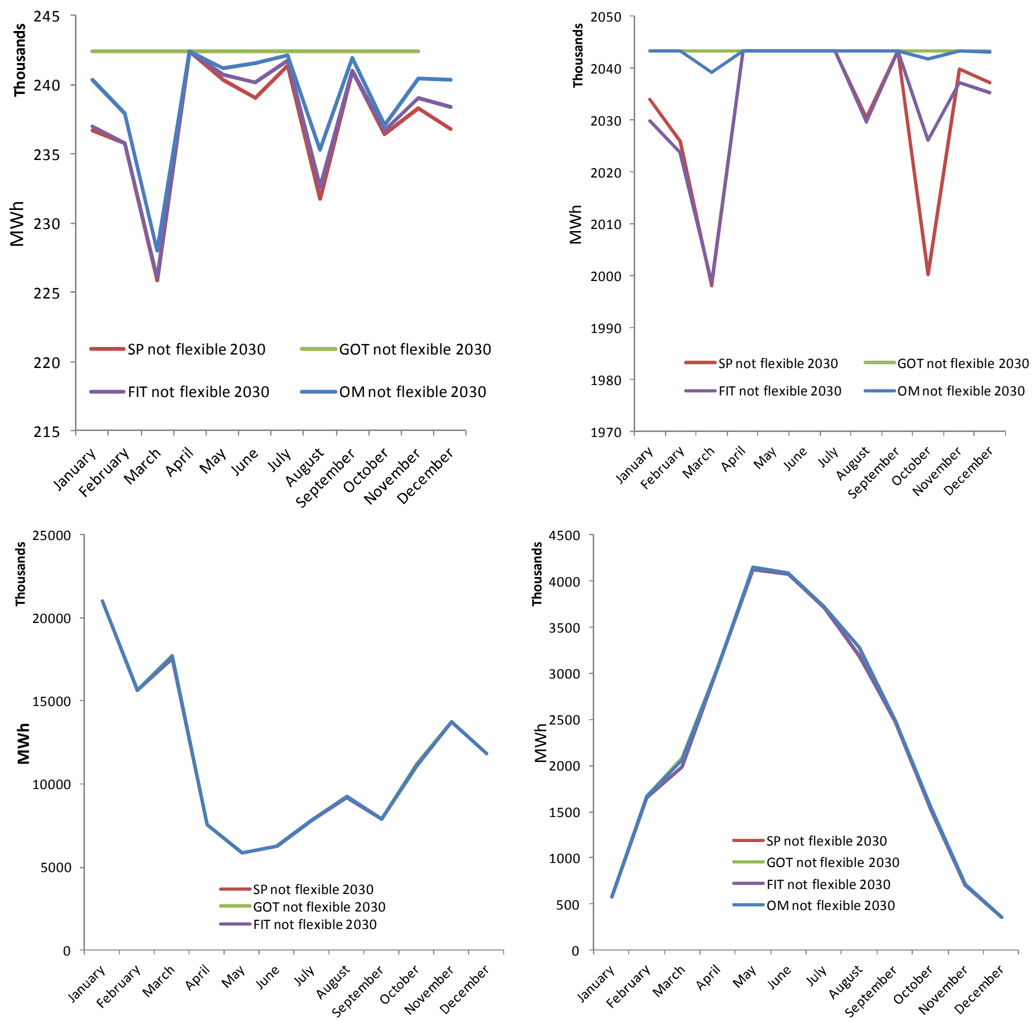
Figure 4.2: Duration curve of the residual demand.



Source: own illustration, data from the PowerACE model.

As explained in section 3, in 2030 it is assumed that all the nuclear plants will shut down and the percentage of hard coal will steeply decrease as well, whereas the percentage of gas plant is almost doubled. Apart from the nuclear, that will be phased-out for politically reasons, the rest are results of the optimization model, so they are used as assumption. Anyway this seems to be a possible scenario because the renewables reduce the average utilization of the conventional plants, which increases the specific capital costs (Nicolosi, 2012), and the cheap conventional plants are the first that face this effect. This can be seen in Figure 4.2 where the duration curve of the residual demand is shown (for the definition of residual demand see Appendix 1). The duration curve shows the number of hours in the year where the residual demand was higher than a certain value. For instance, in 2030, for 30% of the hours in the year the residual demand was higher than the 58% of the maximum residual demand whereas in 2020 it was higher than the 65% of the maximal demand. This effect is much stronger at low levels of residual demand, because the renewable are taking the place of the base load plants, for instance in 2030, 20% of the residual demand it was request for 89% of the time, whereas in 2020 was necessary for 99% of the hours in the year. This leads to a lower utilization of the base load plants which have to run more hours to recover the high investment costs. As peak plants do not face the same situation, this effect coupled to the high installed capacity explains the increased gas share in 2030. In the flexible scenarios with 2030, and in all the scenarios with 2020 as base year, the energy product from renewable sources is almost completely dispatched. In the not flexible scenarios with base year 2030 the constant renewable generators are often curtailed whereas the VRE are almost completely dispatched. For instance, the monthly dispatched generations for the Biogas and the Hydro Power are shown in Figure 4.3 (for the monthly generation's chart of the Biomass and the geothermal power see Appendix 5).

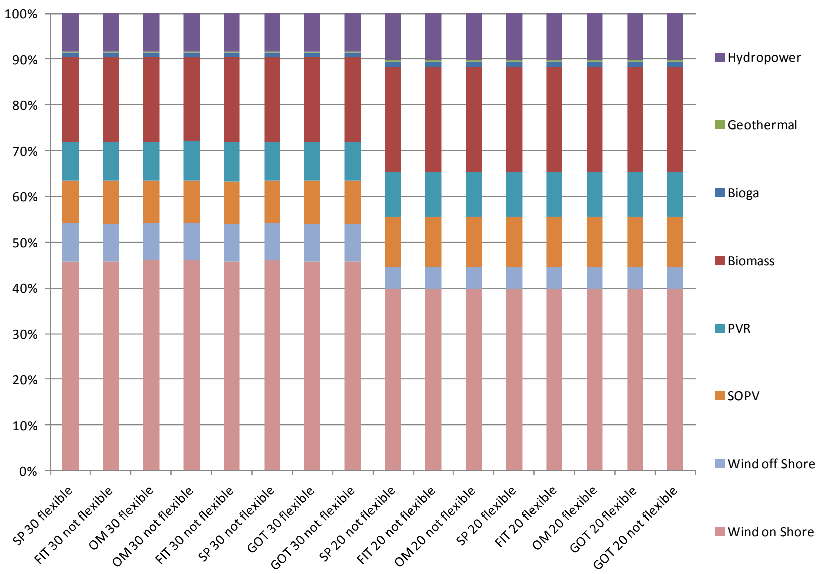
Figure 4.3 : Monthly generation of biogas (top left) and hydropower (top right) onshore wind (bottom left) and solar PV (bottom right).



Source: Own calculation. Data source: PowerACE model.

As the output of the VRE is determined by the weather, their generation is concentrated in some period of the year; with the growth of variable renewables higher frequency of surplus situations with negative price can be expected in the near future. Creating a merit order of voluntary RES-E shutdowns is one of the intentions of the market premium model. The aim is to reduce the negative prices and prevent the disconnecting or switching-off of the thermal plants for a short period, that could cause high costs and also technical difficulties (Klobasa et al., 2013). The model results shows that the constant renewable generators react to the surplus situations. In 2030 they represent 13% of the total generation (see Section 4.3).Therefore they cannot exert a considerable dampening effect. As could be expected the generation in 2030 is higher than in 2020 (see Section 4.3 for the penetration) due to the increase of installed capacity. Even the generation mix of the renewable changes due to the different installed capacity mix. The only factor that has visible impact on the mix and total generation of renewables is the priority dispatch.

Figure 4.4: Annual generation mix of the RES-E.:



Source: Own illustration. Data source: PowerACE model.

4.3 Penetration ratio and Capacity Factor

In all the scenarios with base year 2020 the REs are almost entirely dispatched (see Section 4.2); hence penetration ratios and capacity factors are roughly the same in all the scenarios. The overall RES-E penetration ratio is 35.8% where 23% is from VRE. Wind power has a share of 16% on the total demand and solar power the remaining 7.5%.In Table 4.1 the annual average capacity factors for the year 2020 are presented, which are roughly in line with current levels.

Table 4.1: Capacity factors in 2020.

Biogas	Bio-mass	Geother-mal	Hydropower	PVR	SOPV	Off shore wind	On shore wind
[%]	[%]	[%]	[%]	[%]	[%]	[%]	[%]
59%	67%	25%	42%	10%	10%	18%	19%

Source: Own Calculation. Data obtained with PowerACE.

As expected, the constant generators have higher capacity factors due to their technical possibility to be dependent just to the economic incentives whereas the generation of the VREs depends mostly on the weather conditions.

Also in 2030 the penetration ratio has almost the same value among the different schemes. This could have been foreseen in light of the consideration in Section 4.2, or from the small amount and similar number of hours with negative prices among the scenarios (see Section 4.5.2 and 4.5.1 General Market Parameters). The negative electricity prices occur when in the power market there is a surplus situation. Surplus situation means that the residual demand, demand minus the RES-E generation, is lower than the must run generation for suppliers of ancillary services[21] and exports to other countries. So the small number of hours with negative price means that surplus situations seldom occur and this explains why the RESs are almost completely dispatched. Furthermore as the values are similar among the scenarios it is difficult to quantify the effect of the different policies on the penetration ratio and the capacity factor. Although there are small differences among the scenarios, the flexible scenarios always present

21 The generators in the reserve market, have to be online and operating in order to be able to adequate their production for balance short term demand fluctuation or blackout and to ensure adequate system reliability. So far, in the regulatory framework, is still missing to enable fluctuating REs to participate in the reserve market. The thermal power plants have technically constraints (that are simulated in the model)regarding the minimum load that is roughly 40% of the nominal load; hence the thermal power stations in the reserve market, have to offer 40% of their nominal power in the spot market to a very low price to ensure that they can be online.

higher penetration ratios, because there is no capacity from the generators in the reserve market sold in the power market and hence the RESs are the first that are dispatched.

The RE overall penetration ratio is 49.1-49.3% where 35.3-35.4% is due to the VRE. Wind power has a share of 26.5-26.6% on the overall yearly generation and the solar power the remaining 8.7-8.8%.

The capacity factor increases of 1.6-2% from 2020 (the capacity factor changes are shown in Table 4.2, whereas for the capacity factor in 2020 see Table 4.1). The capacity factor depends on the plant availability, the technical efficiency of the energetic conversion and to the possibility to be dispatched in the wholesale electricity market, which is related to the merit-order curve.

The small growth of the capacity factor is likely due to the assumption about the working hours in section 3. The merit-order curve changes are lead by the coupled effect of the REs support policy and the different conventional fleet in the 2030. The renewable policies influence the merit-order curve because they affect the bidding behavior of the RE generators. The parameters that influence the bid of the REs are the *fuel cost*, the *FiT values* and the *MV* (for a complete explanation see Section 3, for a summary see Section 4.2). The capacity mix of the conventional power station fleet, in 2030, is different from the one in 2020 (see Figure 3.8). The replacement with gas of technologies as nuclear, hard coal, lignite, that have lower variable costs, leads to higher average market electricity price (see Section 4.4.1, 4.4.2, 4.5.1, 4.5.2-General Market Parameters) and changes the shape of the merit-order curve in the conventional part. Table 4.2 shows the variation of the capacity factors for the VRE generators.

As there is no clear differences among the different policies it seems that, *at this penetration level* the effect of the assumed changes in the conventional fleet have a predominant impact over the merit-order changes due to the REs, although the merit-order effect due to a different support policy could be present at higher penetration of VRE.

Table 4.2: The table contains the variations of the capacity factor from 2020 for the fluctuating renewable technologies.

	PVR	PV	Off shore wind	On shore wind
	[%]	[%]	[%]	[%]
FiT				
Flexible	1.7	1.7	1.4	2.0
Not flexible	1.7	1.6	1.4	1.9
GOT				
Flexible	1.7	1.7	1.4	2.0
Not flexible	1.7	1.7	1.4	2.0
OM				
Flexible	1.7	1.7	1.4	2.0
Not flexible	1.7	1.7	1.4	1.9
SP				
Flexible	1.7	1.7	1.4	2.0
Not flexible	1.7	1.6	1.4	1.9

Source: Own research.

The variation of the capacity factors from 2020 to 2030 of the dispatchable generators are shown in Table 4.3. The value is always between -0.1 and 1.2%. The reduction of the utilization of the dispatchable generators is because they adjust their production when a surplus situations occurs in the power market (see Section 4.2)

Table 4.3: The table contains the variation from 2020 of the capacity factor for the constant renewable technologies.

	Biogas	Biomass	Geothermal	Hydro Power
	[%]	[%]	[%]	[%]
FiT Flexible	0.9	0.7	0.0	0.6
FiT Not Flexible	0.0	0.7	0.0	0.4
GOT Flexible	1.2	0.7	0.0	0.6
GOT Not flexible	1.2	0.7	0.0	0.6

OM Flexible	1.0	0.5	0.0	0.6
OM Not flexible	0.4	-0.2	0.0	0.6
SP Flexible	0.8	0.7	0.0	0.6
SP Not flexible	-0.1	0.6	0.0	0.4

Source: Own calculation. Data obtained with PowerACE.

4.4 Simulation results of the year 2020

4.4.1 Not flexible scenario

General Market Parameters

In Table 4.4 are collected the general market parameters from the simulation with not flexible scenario in 2020.

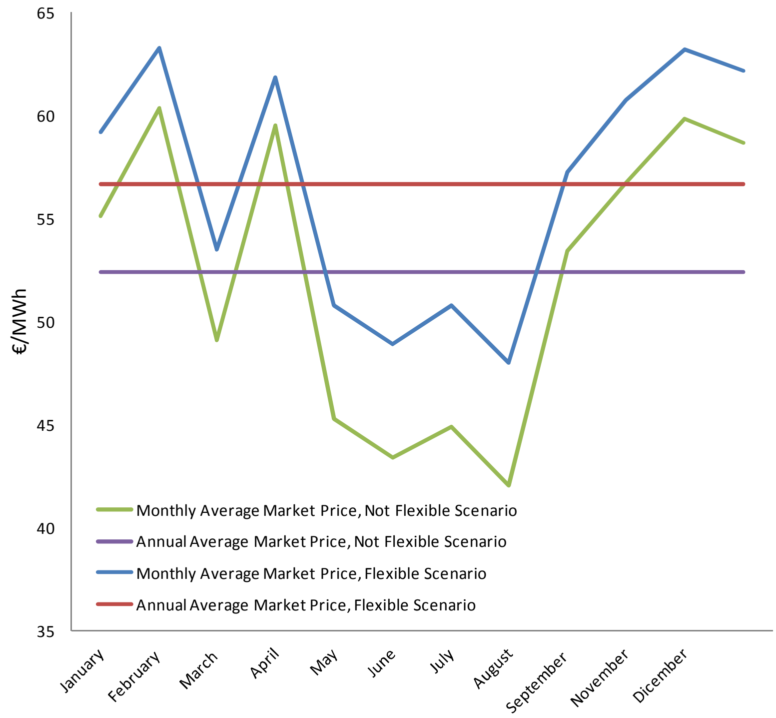
Table 4.4: General market results from the simulation with not flexible scenario, year 2020.

Support Scheme	Average Market Price	Maximum Price	Minimum Price	Standard Deviation	Negative price Hours
	[€/MWh]	[€/MWh]	[€/MWh]	[€/MWh]	[hours]
FIT	52.373	85.2	-69.2	19.089	2
GOT	52.355	85.2	-150.0	19.247	2
OM	52.392	85.2	11.0	19.013	0
SP	52.384	85.2	-20.4	19.035	2

Source: Own calculation. Data Source: Power-ACE model.

All the support mechanisms present the same evolution of the monthly average market price during the year (Figure 4.5). Every scenario´s price curve has the same shape but their positions on the graph are shift according the yearly average market price. As can be seen in Table 4.4, the schemes present subtle differences in the yearly market price (from the lower yearly average market price to highest is just 0.04 €/MWh). Hence in the following is shown just the yearly evolution of the spot market price for the Sliding Premium scheme (see Figure 4.5).

Figure 4.5: Yearly price evolution for the simulation in year 2020.



Source: Own calculation. Data Source: Power-ACE model.

In the light of the RES-E bidding behavior algorithms (see Appendix 9, Appendix 10, Appendix 11) it could have been foreseen that the OM scheme presents the highest yearly average market price. The OM algorithm sets the generator´s bid price at their marginal cost, which cannot be negative, instead of the other schemes that normally bid in the market at negative price. The lower average market price is set by the GOT scheme, due to its bid price that always is -150 €/MWh.

As explained above, the REs supported by the OM scheme bid at their marginal cost in the spot market. The marginal cost for a VRE is assumed to be 0 €/MWh, and for the biofuel-fired plants is the assumed equal to their fuel cost (see Biofuel prices). Whereas, the RES-E normally bids in the power market at negative price when they are supported by the other support schemes[22] (see Appendix 9, Appendix 10, Appendix 11),the conventional plants bid at their variable cost, where the cheap base-load technologies, as nuclear and lignite, are bidding close to the RES-E marginal costs (see Table 3.5). In 2020 the majority of the conventional load is served by the base load generators (see Section 4.2). Considering these aspects, it becomes clear why the OM scheme presents the smallest Standard Deviation followed by the Sliding Premium (0.1% higher than the OM), Feed in Tariff (0.4% higher than the OM) and the Grid Operator Trader (1.2% higher than the OM).

The *number of hours with a negative price* can be used as a *qualitative* parameter to asses how many times the renewable generators are setting the price in the spot market, because, as is explained above, the RE generators are the only generators bidding at negative price (also the must run capacity bid at negative price but normally the demand is not that low to call just the “must run” of the reserve).

In this scenario, the different support mechanisms have small impact on the general market parameters (see Table 4.4). The impact is difficult to be assessed because the renewable are seldom setting the price (see hours with negative price in Table 4.4). Therefore the market is little affected by the different bidding behaviors of the RES-E. This may be due to the small share of RES-E in the power market compared to the conventional generation (see Section 4.3).

The minimum prices show better the impact of the different RES bidding behaviour on the market prices. The lowest clearing price present is from the Grid Operator Trader scheme and is -150 Euro per Mega Watt Hour (€/MWh), that means that it was a RES to set the price. The next lower price is set by the FIT scheme (roughly 46% of the GOT scheme) followed by the SP (14%) and OM with a positive value of 11€/MWh. With a difference of 161€, on the clearing price this hour clearly shows the deep difference in how differently the RE generators bid in the market if supported in a different way. In

[22] In the SP scenario the bid price could even be positive because is also function of the MV and marginal costs. The RES generators have a positive bid price when the MV plus the marginal cost is higher than the FIT value. This may happen for the Biogas and Biomass but they represent a small part of the RESs. Hence, even for the SP scenario bid from the RESs have mostly negative price.

the Feed in Tariff (FIT) scheme the minimum price is reached just once, whereas in the other schemes the minimum clearing price is reached twice.

This is due to the fact that the different support scheme generate different merit order and consequently they brought on line different RES. For instance, in Appendix 6 and Appendix 7, is shown the generation dispatched outlook in the hours where is reached the minimum price for the FIT and Sliding Premium (SP) scenarios.

In this hour the FIT scenario brought online biogas and more hydro power, compared to the SP scenario, in the same hour. The hourly generation of the biogas and part of the hydropower, produced in the FIT scenario, is entirely supplied by the Solar Photovoltaic Power (PV) in the SP scenario.

In the FIT scenario[23], is dispatched more Hydro Power in place of the PV because for some years his FIT value is higher than the PV´s FIT value (see Figure 3.9); the biogas has never higher FIT value than the PV but from 2000 up to 2003 the Biogas FIT value coincide to the Hydro Power FIT value, so probably the Biogas was brought online only by coincidence. In the Open Market (OM) scheme the Biogas is dispatched as in the FIT scheme and furthermore even waste[24] is dispatched.

The price is set by either the Biomass or Biogas, as the most expensive technology dispatched in these hours, see Appendix 8, moreover the price correspond exactly to the Bio-fuel price that is assumed to be equal to his marginal cost (see Section 3.5.1).

RE Parameters

Annual Market Value

The annual MV of the constant generators is shown in Table 4.5.

[23] In the FIT bidding behaviour the marginal costs (MC) are not considered (see Appendix 10: Bidding behaviour algorithm for the RE bidder supported by the Feed in Tariff mechanism.)

[24] The marginal cost of the Waste technology, in the simulation, is assumed equal to 0 €/MWh.

Table 4.5: Annual MV of the RE dispatchable, not flexible scenario, year 2020.

Support Scheme	Biogas	Biomass	Geothermal	Hydropower
	[€/MWh]	[€/MWh]	[€/MWh]	[€/MWh]
FIT	52.38	52.35	52.35	52.35
GOT	52.33	52.33	52.33	52.33
OM	52.37	52.37	52.37	52.37
SP	52.38	52.36	52.36	52.36

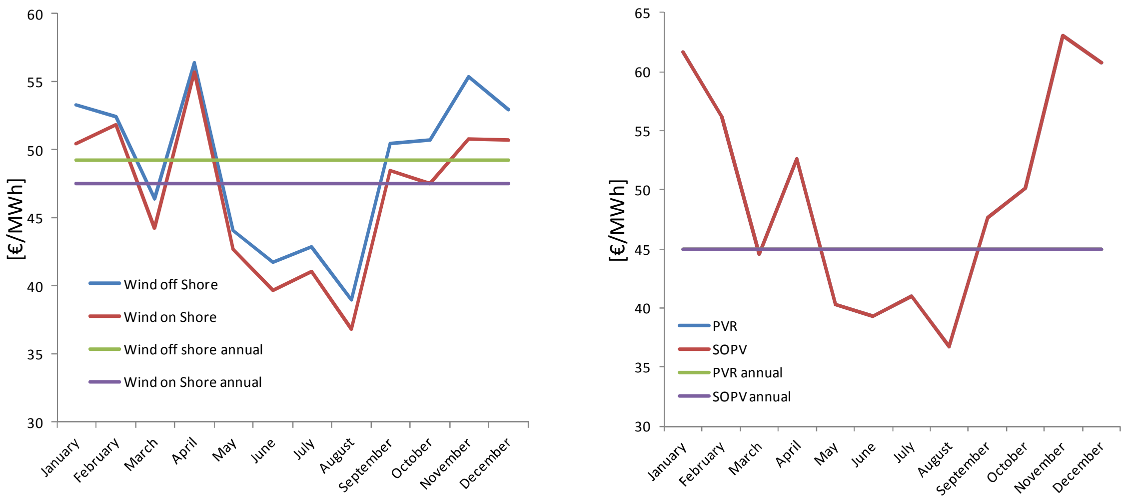
Source: Own calculation. Data source: PowerACE model.

The annual market value of the VRE is shown in Table 4.6; whereas the monthly MVs are shown in Figure 4.6.The MV are presented just for one scheme because they are really similar among the different scenarios.

Table 4.6: Annual MV of the RE partially dispatchable, not flexible scenario, year 2020. Own calculation. Data source: PowerACE model

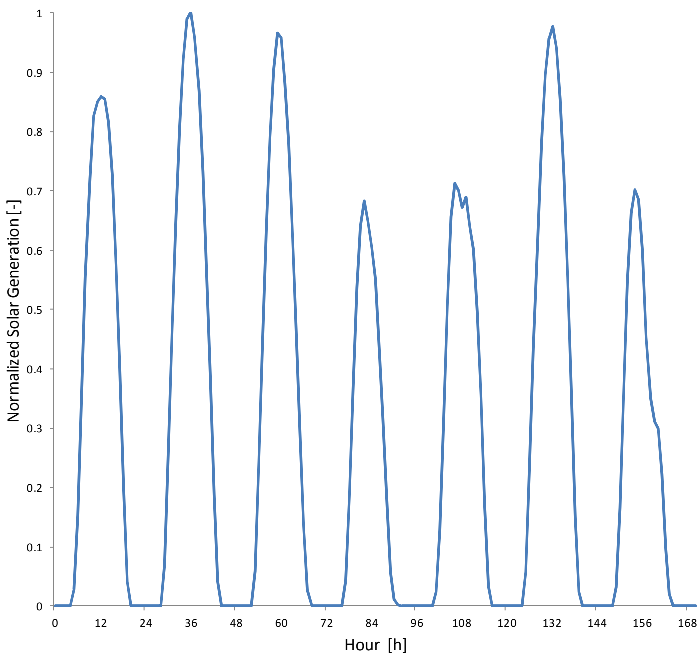
Support Scheme	PVR	PV	Off shore wind	On shore wind
	[€/MWh]	[€/MWh]	[€/MWh]	[€/MWh]
FIT	44.8684	44.8710	49.1973	47.4620
GOT	44.7615	44.7615	49.1515	47.4181
OM	44.9715	44.9715	49.2414	47.5043
SP	44.9310	44.9310	49.2241	47.4877

Figure 4.6: Monthly MV 2020, Own calculation. Data obtained with PowerACE.



The monthly wind value follows the shape of the monthly average market price but all the values are shifted down (see Figure 4.5). This means that when the wind is producing the spot market prices are low. The distortions from the monthly energy price are due to the moment when the generators feed-in the energy, in other words, to generation profile. The PV has more "peaky" generation compared to the wind. In fact, the solar MV value drops down deeply during the summer, because the yearly solar generation is mostly concentrated in that period. Furthermore, the solar value is more sensible to the penetration rate because its production has even a daily periodicity, due to solar irradiation nature (see Figure 4.7, that leads to have high generation in few hours, where consequentially the price drops down and hours without any production.

Figure 4.7: Solar normalized generation profile of the first week of July.



Source: Own illustration.

Annual Market Value Factor

As was introduced, the market value factor of the dispatchable sources is close to 1 (see Table 4.7) because they are able to adjust their production based on the economic incentives.

Table 4.7: Annual MVF of the RE dispatchable, not flexible scenario, year 2020.

Support Scheme	Biogas	Biomass	Geothermal	Hydro Power
	[-]	[-]	[-]	[-]
FIT	1.0005	1.0000	1.0000	1.0000
GOT	1.0000	1.0000	1.0000	1.0000
OM	1.0001	1.0000	1.0000	1.0000
SP	1.0003	1.0000	1.0000	1.0000

Source: Own Research.

Whereas the MVF of the fluctuating REs is lower than 1 there is no clear result about the effect of the different bidding behaviour on the MVF. The SP scheme presents higher MVF compare to the FiT, but the differences are at the third digit after the decimal point, so they are not very relevant.

Table 4.8: Annual MVF of the RE partially dispatchable, not flexible scenario, year 2020.

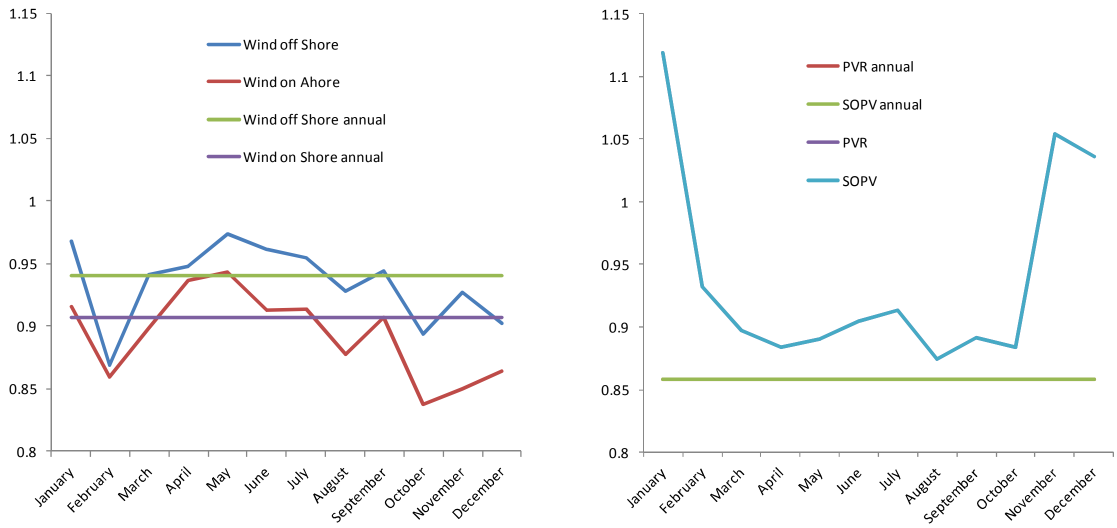
Support Scheme	PVR	PV	Off shore wind	On shore wind
	[-]	[-]	[-]	[-]
FIT	0.8571	0.8571	0.9398	0.9066
GOT	0.8553	0.8553	0.9392	0.9061
OM	0.8587	0.8587	0.9403	0.9071
SP	0.8581	0.8581	0.9401	0.9069

Source: Own Research.

The MV is the weighted average of the *spot electricity prices*, where the weight is the hourly generation of the considered technology. It expresses the “average market price” seen from the considered technology, or in other words the *value* of the wind in the market. Whereas, the MVF, is the weighted average of the *relative prices*, where the base price is the average market price. Therefore the MVF is useful to asses whether the considered technology is producing in hours where the price is high. The monthly MVF of the wind (Figure 4.8) present a different shape from its MV (see Figure 4.6). This means that when the wind is dispatched the energy market price deviates from the monthly average. The wind generation is high from October to March, but from January to March is decreasing and from September to December is increasing. Looking at the

Figure 4.8 it can be noticed that distortion of the MVF curve from the wind value curve is exactly the opposite. The maximum monthly wind value occurs when there is the minimum wind generation and vice versa. This means that the feed-in of the wind power involves the price to deviate from its monthly average. This result it was expected from the literature, and shows that the high in-feed of VREs leads to reduce their MVF their self.

Figure 4.8: Monthly MVF of the VREs, not flexible scenario 2020.



Source: Own Calculation. Data Source: PowerACE model.

For the solar power the distortion in shape from the solar value is smaller. This means that the hourly price when the solar technologies are producing is in line with the monthly average market price.

The annual solar MVF is lower than the monthly value curve. The reason why the annual solar MVF is shift from the monthly curve could be easily understand in light of the Equation 5.

Equation 5: Annual MVF.

$$MVF_{annual} = \sum_{i=0}^{12} \frac{G_{monthly}}{G_{annual}} \cdot \frac{\bar{p}_{monthly}}{\bar{p}_{annual}} \cdot MVF_{monthly}$$

The annual MVF, differently from the MV, is not the weighted average of the monthly MVF. In other words, annual and monthly MVF are weighted averages of relative prices with different base prices. The fact that the annual MVF is lower than the monthly curve means that big part of the solar generation was produced when the average market price was low.

4.4.2 Flexible Scenario

General Market Parameters

In Table 4.9 are collected the General Market Parameters from the flexible scenario simulation in 2020.

In this simulation there is no clear result regarding the impact of the considered different mechanism for supporting the RE in the electricity market (see Table 4.9).This is due to the coupled effect of the assumption of flexibility and to the fact that, in 2020, the share of the RES in the electricity market is supposed to be quite small. The effect of these two assumption leads to the fact that the RE are always dispatched and, in this case, they are never the last technology called to produce; that means that they never set the market price. These results could be expected in the light of the few hours with negative prices from the simulation with not flexible scenario in the same year (see Section 4.4.1 General Market Parameters Table 4.4).

Even if is not possible a comparison between the different policy impact is still possible to compare the results as flexible and not flexible scenarios (see Section 5)

Table 4.9: General market results from the simulation with flexible scenario, year 2020.

Support Scheme	Average Market Price	Maximum Price	Minimum Price	Standard Deviation	Negative price Hours
	[€/MWh]	[€/MWh]	[€/MWh]	[€/MWh]	[hours]
FIT	56.649	85.2	24.2	15.511	0
GOT	56.649	85.2	24.2	15.511	0

OM	56.649	85.2	24.2	15.511	0
SP	56.649	85.2	24.2	15.511	0

Source: Own Research.

RE Parameters

In light of what is discussed in the Section sopra the RE parameters will be presented just once, without any reference to the support mechanism, because the results are the same for all the schemes. Furthermore, even the monthly evolution and the comments of the MV and MVF are not presented because has the same evolution of the not flexible scenarios but they are shift according the value in the following tables (see Section 4.4.1).

Annual Market Value

Table 4.10: Annual MV of the RE dispatchable, flexible scenario, year 2020.

Biogas	Biomass	Geothermal	Hydro Power
[€/MWh]	[€/MWh]	[€/MWh]	[€/MWh]
56.6303	56.6303	56.6303	56.6303

Source: Own Research.

Table 4.11: Annual MV of the RE partially dispatchable, flexible scenario, year 2020.

PVR	PV	Off shore wind	On shore wind
[€/MWh]	[€/MWh]	[€/MWh]	[€/MWh]
50.2162	50.2162	54.1010	52.8081

Source: Own Research.

Annual Market Value Factor

Table 4.12: Annual MVF of the RE dispatchable, flexible scenario, year 2020, Own calculation.

Biogas	Biomass	Geothermal	Hydro Power
[-]	[-]	[-]	[-]
1	1	1	1

Table 4.13: Annual MVF of the RE partially dispatchable, flexible scenario, year 2020.

PVR	PV	Off shore wind	On shore wind
[-]	[-]	[-]	[-]
0.8867	0.8867	0.9553	0.9325

Source: Own Research.

4.5 Simulation Results of the Year 2030

4.5.1 Not Flexible scenario

General Market Parameters

Table 4.14: General Market parameters, 2030 not flexible scenario.

Support Scheme	Average Market Price	Maximum Price	Minimum Price	Standard Deviation	Negative price Hours
	[€/MWh]	[€/MWh]	[€/MWh]	[€/MWh]	[hours]
FIT	67.88	100	-83	23.5	173
GOT	66.48	100	-150	32.6	173
OM	69.62	100	0	13.8	0
SP	69.12	100	-30	16.4	159

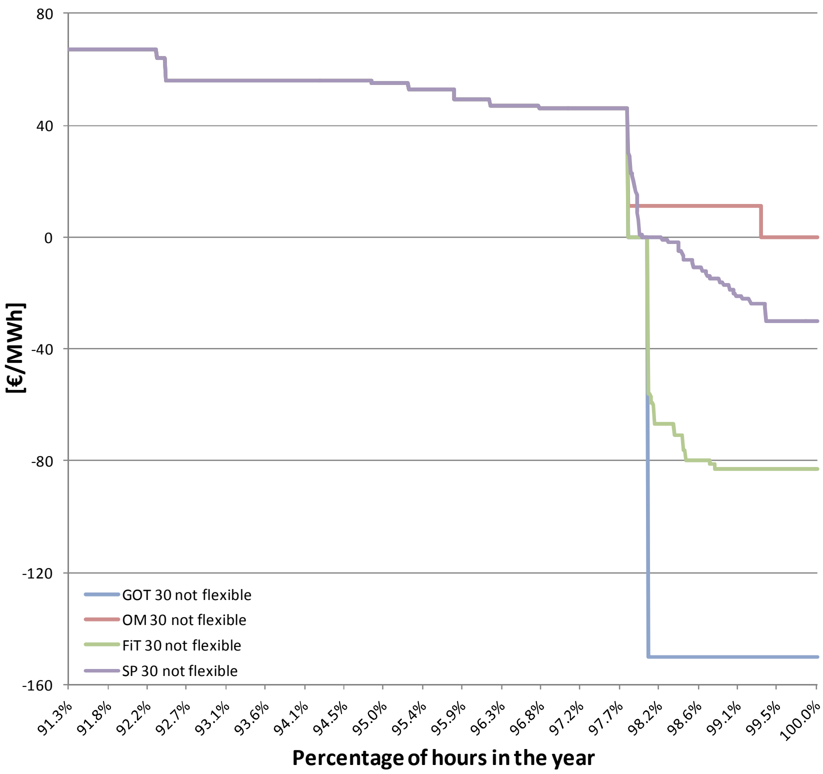
Source: Data retrieved with PowerACE.

In Table 4.14, the general market parameters are presented. In 2030 is more clear the impact of the bidding behavior. For instance, the impact can be noticed on the annual average market prices and on the standard deviation. The more the scheme is *market oriented*[25] the higher is the average market price and smaller is the standard deviation. That is due to the bid prices of the RES-E, which are closer to bid of the conventional power stations. The biggest difference is between the GOT and the OM. The standard deviation in the GOT scheme is 18.8 €/MWh higher than in the OM, and the annual average energy price is 3.14 €/MWh higher in the OM. The considerations about the

[25] For the explanation of market oriented scheme see Appendix 1: Definitions.

minimum and maximum price are similar to the one in Section 4.4.1-General Market Parameters. In the schemes where the RES-E can bid at negative price, the number of hours where the clearing price is negative are not that different. But change the negativity of the market prices according the bidding behavior (see Figure 4.9), and this have a strong impact on the possibility to have revenues of the renewables generators as will explain in the following.

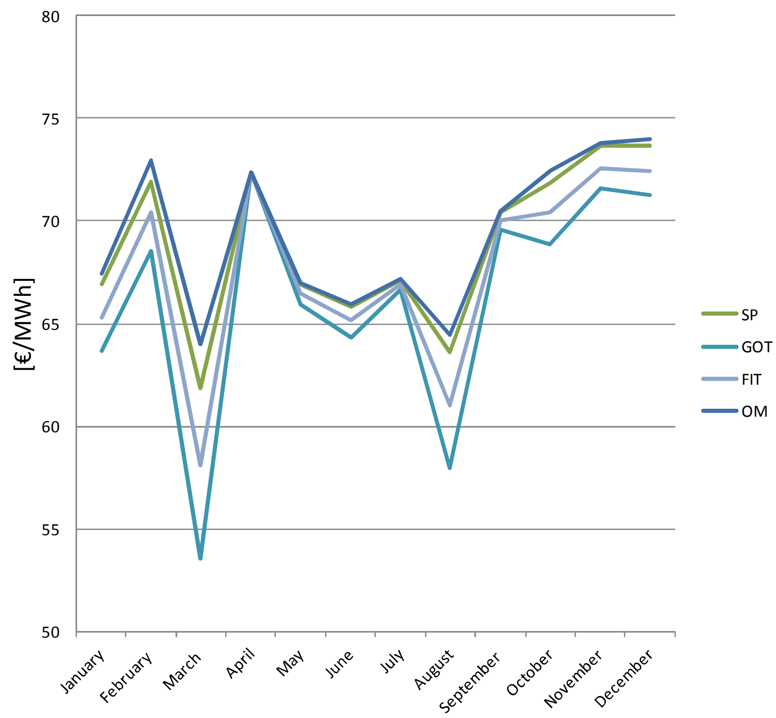
Figure 4.9: Sorted market prices of the not the not flexible scenario 2030, enlargement of the last part.



Source: own illustration. Data obtained with PowerACE.

The most important finding concerns the yearly evolution of monthly average spot market price, see Figure 4.10

Figure 4.10: Monthly average market price, scenario 2030 not flexible.



Source: own illustration. Data obtained with PowerACE.

The bidding behaviour does not have a considerable impact on the total generation, because the renewables are anyway cheaper compared to the conventional technologies (see Section 4.2), but deeply affect the market prices, especially in the months where the feed-in of VRE are high (January to March for the wind power, and July and August for the solar power.

Generally the market prices are higher compared to 2020 likely for: the higher CO_2 price, fuel prices and different conventional fleet (see Section 3). Furthermore the prices do not drop during May, June, and July as in 2020, likely due to the changes in the conventional fleet. The SP scheme compared to the GOT, that is the more market oriented, permits to have even in the months with high feed-in of wind, for example in March, prices definitely higher (in the SP scheme in March the monthly average energy price is 8.25 €/MWh higher than in the GOT scheme).

RE Parameters

The RE parameters for the constant generators are not present in the next sections because they are less relevant compared to the VRE values.

In the interest of simplicity, the monthly MVs and MVFs are presented just for the On shore wind and PV; Off shore wind and PVR are left out because they have similar behavior to the presented technologies.

Annual Market Value

Table 4.15: The Annual market values of the VREs in 2030, not flexible scenario.

Support Scheme	PVR	PV	Off shore wind	On shore wind
	[€/MWh]	[€/MWh]	[€/MWh]	[€/MWh]
FIT	62.25	63.68	62.24	60.65
GOT	59.54	59.54	59.38	56.82
OM	65.37	65.35	65.90	64.52
SP	64.59	65.35	64.77	63.38

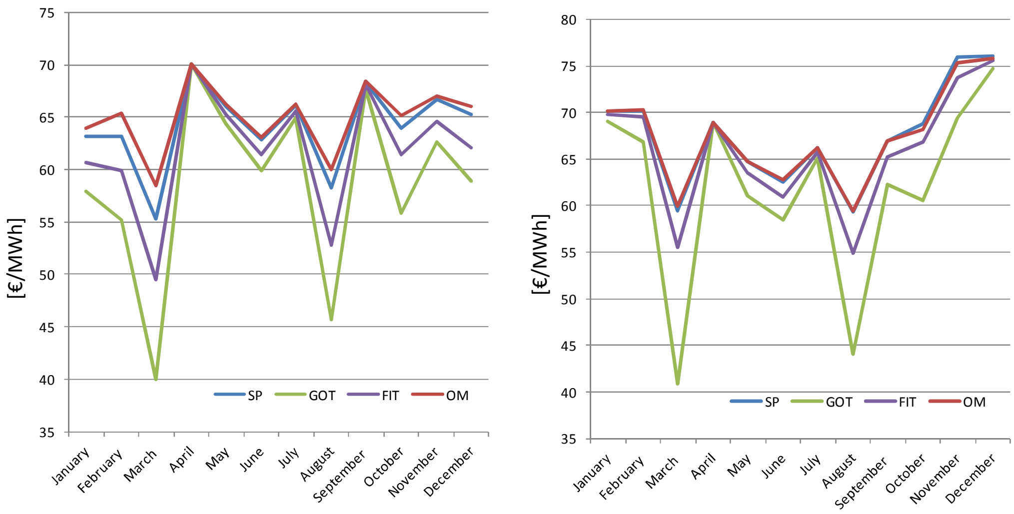
Source: Data obtained with PowerACE.

The annual MVs for the fluctuating energy sources are shown in Table 4.15. In this scenario it is possible to asses the impact of the bidding behavior on the renewable generators.

As the annually average market price, Table 4.14, even the annual MVs are higher when the support scheme is more market oriented. The reasons of this effect could be found on the higher bid price of the renewables.

Higher MVs means, for the partially dispatchable generators, higher possibility to have incomes from the market.

Figure 4.11: Monthly MVs for On shore wind (left) and PV (right) 2030 not flexible scenario.



Source: own illustration. Data obtained with PowerACE.

The monthly evolution of the MV is shown in Figure 4.11. As could be expected, the bidding behaviour has even stronger impact on the monthly market values than to the average market prices. For instance, the wind value in the SP scheme is 15.34 €/MWh higher than in the GOT scheme whereas the market price difference is 8.25 €/MWh. The differences between the support schemes are higher in the months where the feed-in of renewables is high; likely because the REs are setting the hourly price mostly in these periods. As is explained in Section 3, the SP scheme simulates the German Market premium support scheme. The generators earn, for each MWh that they feed-in the grid, a premium that is in charge to the consumers. The premium is calculated as the FiT value minus the monthly market value. Hence higher monthly market value a smaller public cost to support the renewables.

Annual Market Value Factor

The annual MVFs of the fluctuating generators are shown in Table 4.16. The results show that, under considered assumptions, the annual MVFs are higher for the more market oriented schemes as OM and SP.

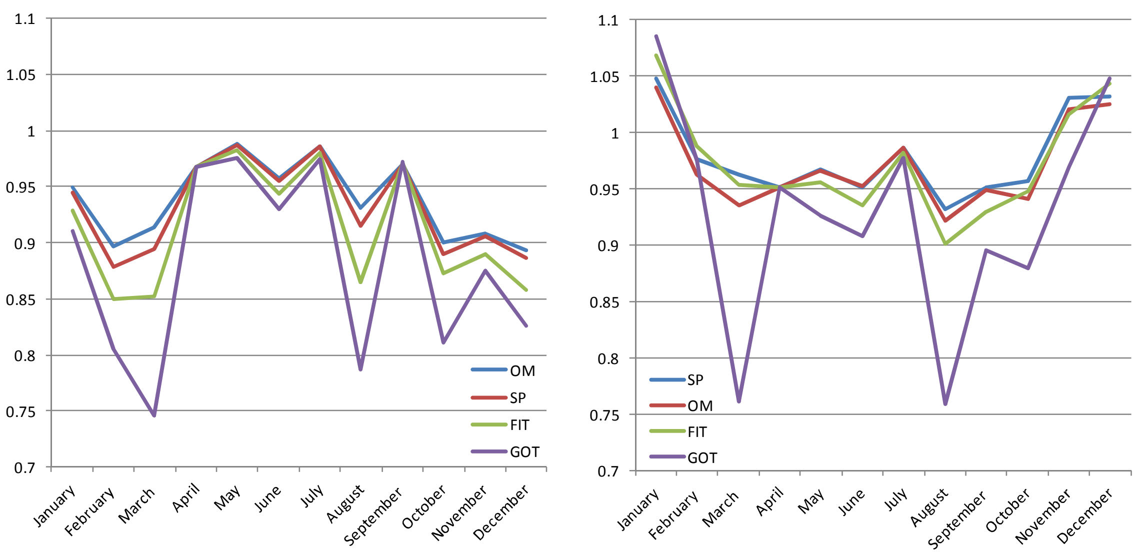
Table 4.16: The Annual MVFs of the VREs in 2030, not flexible scenario.

Support Scheme	PVR	PV	Off shore wind	On shore wind
	[-]	[-]	[-]	[-]
FIT	0.92	0.94	0.92	0.90
GOT	0.90	0.90	0.90	0.86
OM	0.94	0.94	0.95	0.93
SP	0.94	0.95	0.94	0.92

Source: Data obtained with PowerACE.

In Figure 4.12 are shown the monthly development of the value factors for the On shore wind and the PV. Looking at Figure 4.12, the first consideration that could be done is that the market oriented support schemes, as SP and OM, give more stability and higher value during the year to the MVF of the VREs. Another interesting consideration is that the PV value factor during the summer does not drop down as in 2020 likely due to the more stability of the market prices (see Figure 4.10).

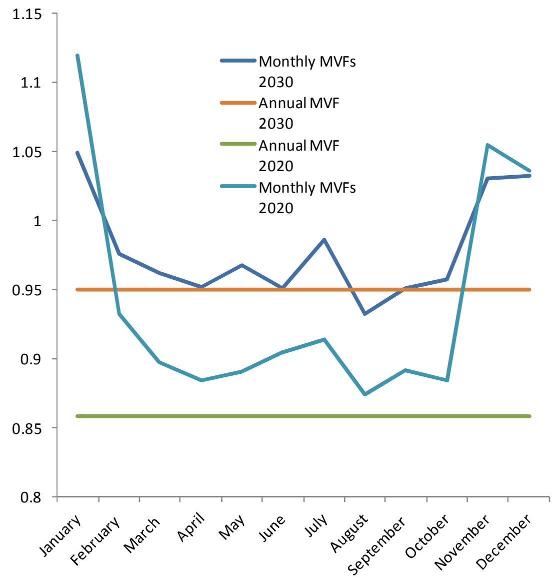
Figure 4.12: Monthly MVFs for On shore wind (left) and PV (right), 2030 not flexible scenario.



Source: own illustration. Data obtained with PowerACE.

The effect of the of the more stability of the market price during year affect the annual market value of the solar power, see Figure 4.13. In the scenario 2020 not flexible, the annual MVF is further from the monthly MVF´s curve than in 2030. In light of Equation 5 and Figure 4.10 is clear that this due average price during the summer months, where the generation of the solar power is high.

Figure 4.13: Comparison PV MVFs of the scenarios 2020 and 2030 not flexible.



Source: own illustration. Data obtained with PowerACE.

4.5.2 Flexible scenario

General Market Parameters

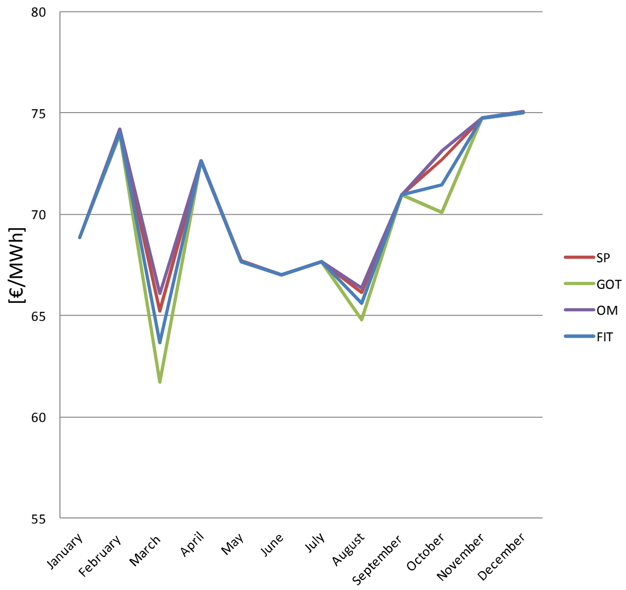
Table 4.17: General Market parameters for the flexible scenario in 2030.

Support Scheme	Average Market Price	Maximum Price	Minimum Price	Standard Deviation	Negative price Hours
	[€/MWh]	[€/MWh]	[€/MWh]	[€/MWh]	[hours]
FIT	70.23	100	-83	14.7	42
GOT	69.88	100	-150	18.6	42
OM	70.65	100	0	11.3	0
SP	70.52	100	-30	12.2	39

Source: Data obtained with PowerACE.

Also in this scenario, the *general market parameters* show the impact on the spot prices of the bidding behaviours of the renewable. The effect is less visible compared to the not flexible scenario, because the renewables are less times setting the wholesale market price (see at the *number of hours with negative price* in Table 4.17; for an explanation why the number of hours with negative price can be use to asses the number of times where the renewable are setting the price see Section 4.1). Although the yearly average energy prices are not really different among the schemes, the impact on the energy market can be better seen from the monthly average market prices development (see Figure 4.14).

Figure 4.14: Monthly average market prices of the scenario flexible, 2030.



Source: own illustration. Data obtained with PowerACE.

RE Parameters

Annual Market Value

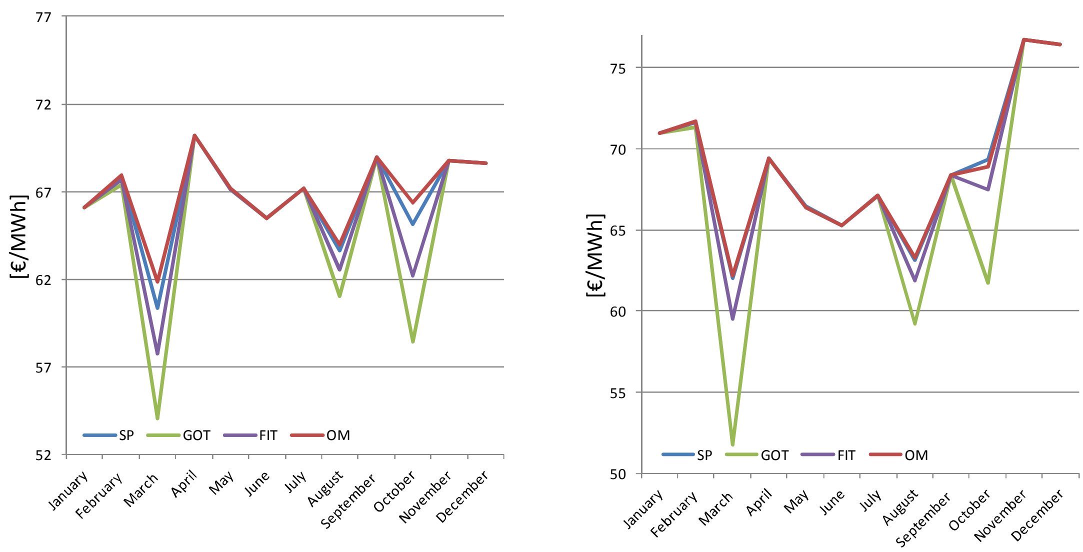
Table 4.18 Annual MVs of VREs of the scenario 2030 flexible.

Support Scheme	PVR	PV	Off shore wind	On shore wind
	[€/MWh]	[€/MWh]	[€/MWh]	[€/MWh]
FIT	66.21	66.66	66.67	65.59
GOT	65.42	65.42	65.68	64.66
OM	67.11	67.11	67.63	66.61
SP	66.85	67.11	67.32	66.27

Source:. Data obtained with PowerACE.

Although the small number of hours where occurs the negative prices, the bid support scheme has considerable effect on the monthly MVs especially on the solar value.

Figure 4.15: Monthly MV´s curves of the scenario 2030 flexible.



Source: own illustration. Data obtained with PowerACE.

Annual Market Value Factor

The annual market value factors are presented in Table 4.18. The effect of the support policy is easier to be asses from Figure 4.17 that shows the monthly evolution of the monthly MVFs. Differently from 2020, the solar value factor do not drop during the summer months due to the more stability of the market prices.

Figure 4.16: Annual MVs of the fluctuating REs in 2030, flexible scenario.

Support Scheme	PVR	PV	Off shore wind	On shore wind
	[-]	[-]	[-]	[-]
FIT	0.95	0.95	0.95	0.94
GOT	0.94	0.94	0.95	0.93
OM	0.95	0.95	0.96	0.95
SP	0.95	0.96	0.96	0.94

Source: Data obtained with PowerACE.

Figure 4.17: The monthly MVF´s curves for On shore wind (left) and PV (right). Scenario: 2030 flexible.

Source: own illustration. Data obtained with PowerACE.

4.6 Summary

The results, within the considered assumption, shown that the policy design do not considerably affect the renewables dispatched generation of the VREs. Anyway, with a higher penetration of renewables, the policy design may affect even the dispatched generation.

In 2020 the impact of the design on the power market can not be clearly assessed. This is due to the still low share of renewable energies.

In 2030 the impact on the market can be assessed. The design of the support scheme has a big effect on the electricity prices (see Figure 4.10 and Figure 4.14). The variation of the average market price is reflected in the market value of the VREs (see Figure 4.11 and Figure 4.15). The bidding behavior affects differently the arithmetic spot market means and the MVs. The MV is influenced even by the generation, and the merit-order effect is higher when high in-feed of fluctuating energy occurs. In other words, when the generation of the fluctuating energy sources is high than the price is lower, therefore the MV is more influenced than the average means from the bidding behavior. The MVF (Figure 4.12 and Figure 4.17) can be used to assess the relative changes between the arithmetic prices means and the MVs. More the residual system is inflexible more the renewable bidding behavior have higher effects on the MV than to the arithmetic mean of the energy prices. This can be seen in Figure 4.12 and Figure 4.17, in the not flexible scenario the bidding behavior has higher influence of the MVFs. The biding behavior has even a strong effect on the fluctuation of the spot market prices, in the not flexible scenario the difference on the standard deviation in 2030 for the not flexible is ca. 15 €/MWh.

The bidding behavior has a stronger effect on the solar technologies than the wind power; this could be due by their different generation profiles, the solar generation is more concentrate in some hours of the day than the wind power.

The flexibility gained by removing the reserve in the spot market appears to blur the effect of the bidding behavior, but it could have more visible impact on higher share of the renewables. This means that the bidding behavior increase the flexibility of the system mainly in the periods where occurs low residual demand whereas the “thermal must-run” affect all the system (see Section 2).From the results, emerge that in the scenario of 2030 the dispatchable renewable generators react to the high in-feed of VREs. Anyway, due to the assumption (Section 3), they represent a small share of the total install capacity; consequentially they have not the ability to exert a considerable dampening effect on the high fluctuation of the residual demand.

5 Discussion

As introduced in section 4.6, the main effects of the market designs are visible in the electricity prices instead of the renewable dispatched generation.

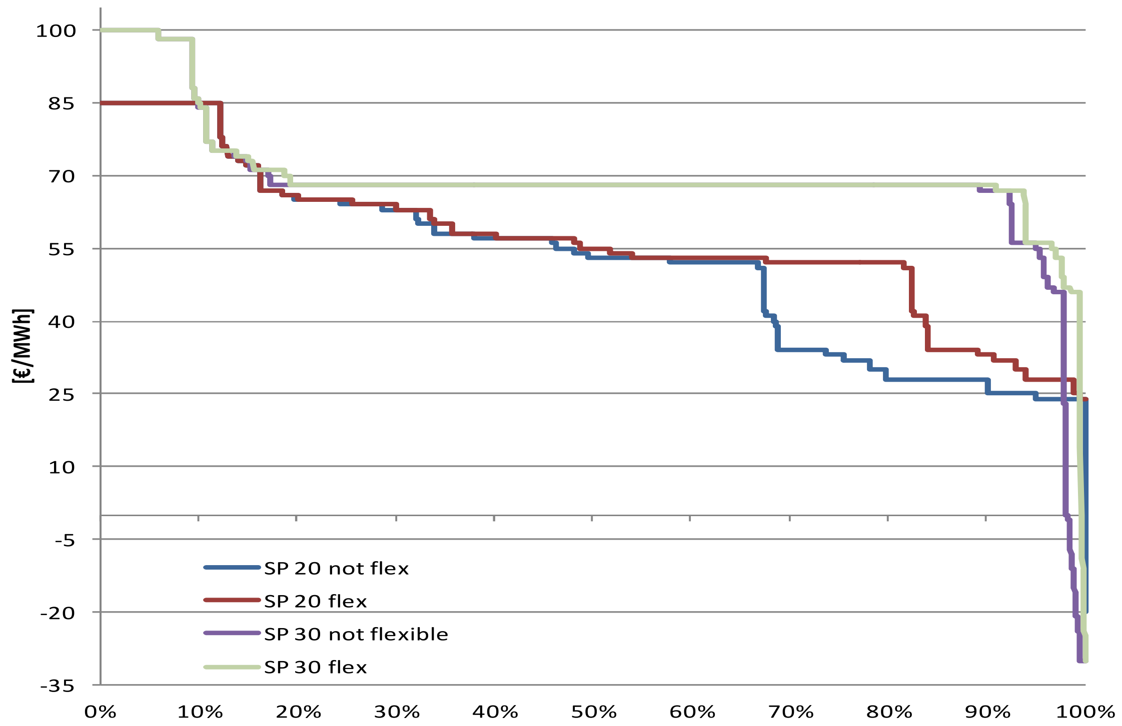
According (Sensfuß F. et al., 2008) , (Hirth, 2013), and (Nicolosi, 2011), the type of the conventional fleet, fuel and CO_2 prices, interconnections among inter/intra-national markets have a big influence on the market price (section 2 gives an overview of the impact of these factors on the market price). The aim of the work at hand is not to asses the single impacts of those parameters on the market prices but rather to asses the impact of the RES-E bidding behavior on the market price and how they interact with the other parameters.

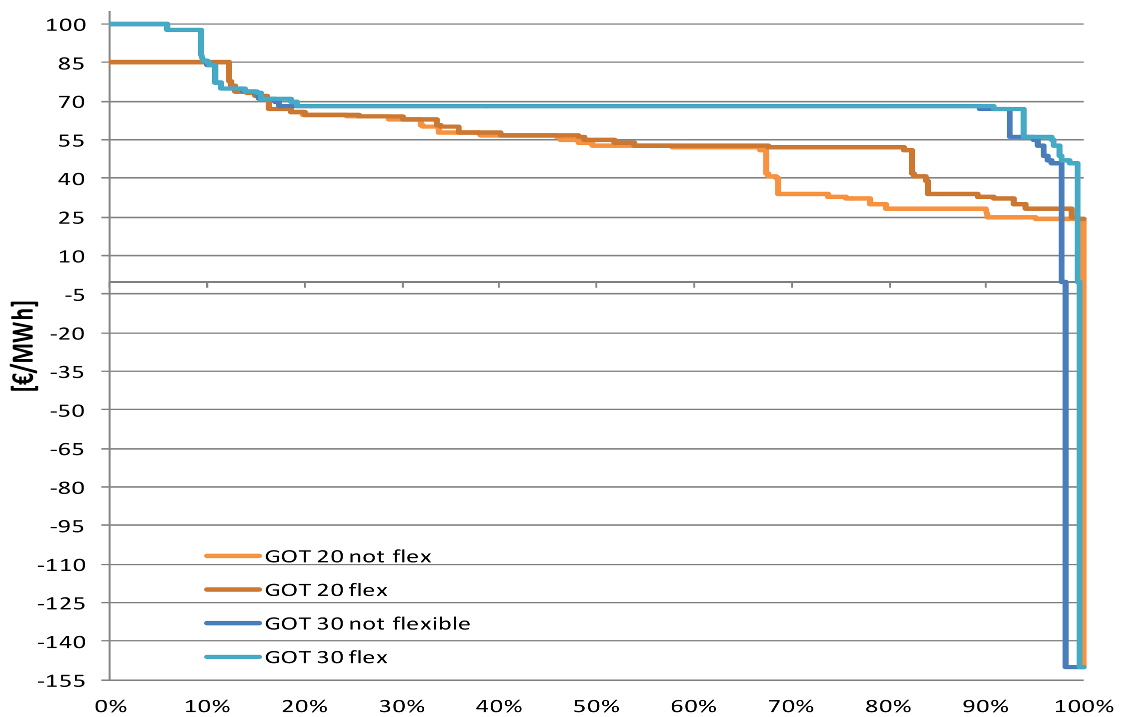
The sorted market price curves for the SP and GOT schemes are in Figure 5.1, the FIT and OM sorted market price curves are not shown because they are similar to the ones presented. From the figures is clear that *the first part of the curves,* until the drop of the price*, is not influenced by the bidding behaviors* because is the same for all the schemes. Hence, the first part of the curve is just influenced by the other effects.

The combination of the more flexible conventional fleet, the higher CO_2 and fuel prices makes the energy prices higher and more stable in the scenarios with 2030 as base year. Moreover the high prices have a longer duration in 2030 than in 2020. Due to the high share of gas. Thus the price is mostly set by the same technology.

The results suggest that the interconnection with the reserve market has a small influence, in absolute terms, on the spot market prices; but it increases the high prices duration (the flexible scenarios, compared to the not flexible scenarios with the same base year, are more shift on the right side of the area chart).

Figure 5.1: Energy price duration curves of the SP scheme (top) and GOT scheme (bottom).

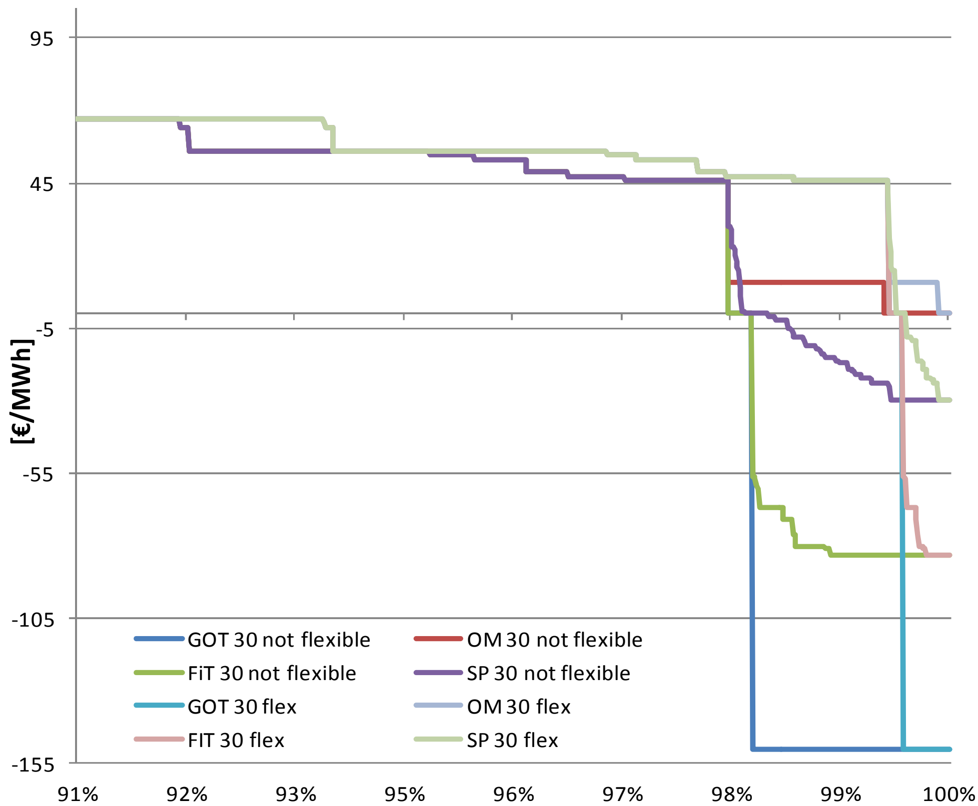




Source: own illustration, data obtained with PowerACE model.

The contractions of the power plants for the reserve influence the overall flexibility of the system. The "must-run" due to reserve market interconnections has a stronger effect on the scenario with base year 2020. This is due likely to the capacity different capacity mix of the conventional fleet. In 2020 the share of base load plants is higher than in 2030, therefore the overall flexibility of the system is much lower in 2020. The base load plants has normally high installed capacity per plant, therefore their obligation to be online all the month have a different effect on overall flexibility of the wholesale market. Figure 5.2 represent the enlargement of the right side of the prices duration curve, where the spot prices drop. This part of the curve represents the oversupply periods (the theoretical framework of the oversupply situations is present in section 2). The oversupply situations frequency decreases with the flexible scenarios as they do not have the "must-run" generation see Figure 5.2.

Figure 5.2: Enlargement of the energy price duration curves for the simulation with 2030 as base year.



Source: own illustration. Data obtained with PowerACE.

The bidding behaviour has impact on the market prices during the oversupply situations. Since the overall flexibility of the system is mainly required in the period of high or low residual demand, is clear how is important that the bidding behaviour of the renewables is harmonize with the market in a order to achieve a flexible and effective system with a high share of renewable energies. Although these situations represent a small number of hours on the entire year, *with high penetration of VREs*[26], the market prices are strongly influenced by these hours, (the monthly average market prices in 2030 are show in Figure 4.14 and Figure 4.10) and consequentially by the support scheme design. The more market-oriented schemes cause fewer distortions to the merit-order curve because their bid prices are closer to the conventional bids, furthermore the RES-E generators are part of the supply curve thus in case of oversupply situation if they are not called to produce because their bid price is to high for the demand, than they cut on their production without any out of market curtailment rule. Therefore in the periods of high in-feed of fluctuating renewables the monthly average market price curve is less influenced. The consequence is higher prices in the hours where there is high generation of renewables, which is translatable as higher MV for the VREs (Figure 4.11 and Figure 4.15 shown the market value of on shore wind and the PV). In other words, the more market-based designs make the electricity price higher and consequentially also the MV of the VREs. The market value expresses the possibility to have revenue from the market for a specific energy source, whereas the value factor is useful for comparing the value of a fluctuating energy source with the constant one (see Section 4.1).

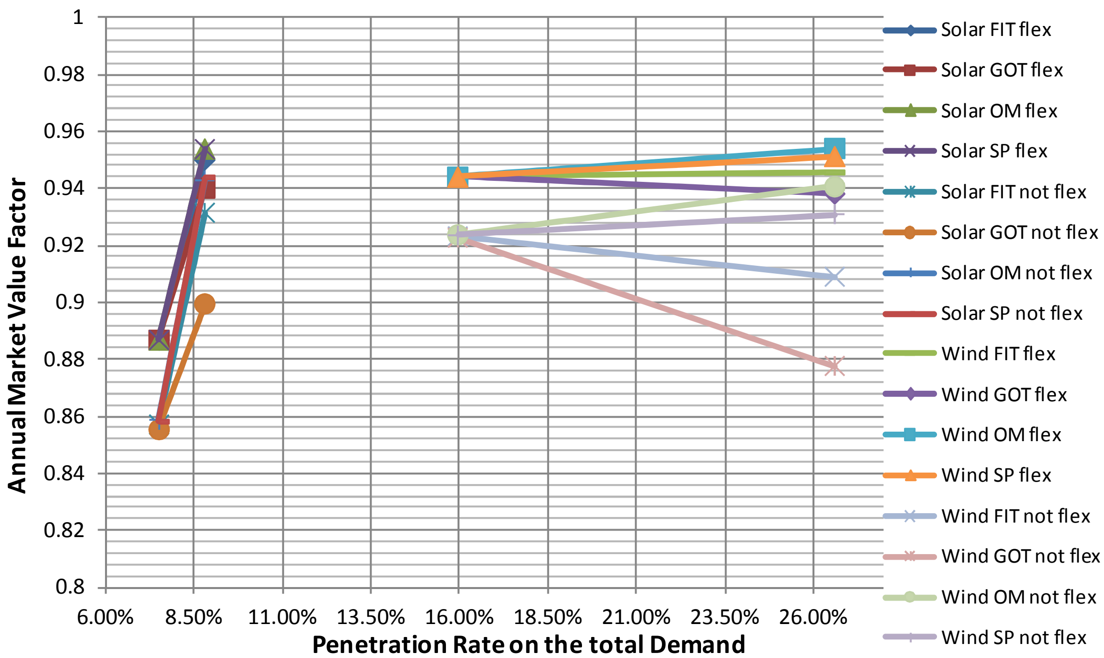
The relative effect between the market price and the MV can be asses with the monthly MVFs (the value factors for on shore wind and PV in 2030 are shown in Figure 4.12 and Figure 4.17). The monthly MVFs show that the more market-based schemes has higher effect on the market revenue possibilities of the fluctuating renewable energy sources than on the average market price. This means that the fluctuating renewables became more favourable in the market if they are supported with a more market-

[26] The scenarios with 2030 as base year have higher RES-E capacity installed. The assumptions and input data are presented in section 3.

oriented scheme. For instance, in March the MVF, under the SP not flexible scenario, is ca. 90% whereas with the GOT not flexible is ca. 75%.

Nonetheless the German Market Premium is based on the monthly market value factor many of the ongoing discussion are focused on the annual market value of the partially dispatchable renewable energy sources, i.e. (Hirth, 2013). As explained in section 4, the annual and monthly market values are both weighted averages of relative energy price but with different basis price. Equation 5 shows how to derive the annual MVF from the monthly MVFs. The monthly value and value factor are more useful to asses the real possibility of income for the variable renewable sources, as their generation is deeply changing among the year, whereas the annual parameters give an overview of the overall response of the market. Figure gives an overview of the deployment of the annual MVF for the solar and wind technology on their penetration on the overall demand.

Figure 5.3:The annual market value factors for wind and solar.



Source: Data obtained with PowerACE. The values are presented in section 4.

The MVFs of the “general technology”, solar and wind, are calculated as arithmetic mean of the particular one (on shore and off shore wind; PV and PVR). The penetration rate is calculated as sum of the singular penetrations.

In 2020 the solar value factor is not influenced by the bidding behaviour as its penetration rate is quite small. But the effect of the bidding behaviour on the solar power is visible in the scenarios with 2030 as base year. Generally, the solar MVF is steeply rising in 2030 due to more flexible residual system. As explained in section 5, the more flexible residual system permits to keep in line the monthly average energy price even during the summer, whereas in 2020 the price was dropping due to high in-feed of the solar power. The only scheme that had not high increase of the annual market value is the not flexible GOT that has ca.5% percentage point less than the other schemes, that means that is the bidding behaviour of the GOT that affect the possibility to have revenue for the solar energies.

The influence of the flexibility on the MVFs due to the reserve interconnections on the annual wind is visible in all the scenarios. The effect is stronger in 2020 due to the less overall flexibility of the supply system.

The effect of the bidding behaviour is visible on the wind value factors of the scenarios with 2030 as base year, likely due to the higher penetration of the wind and the consequentially higher oversupply situations frequency. The scheme that presents the higher annual wind MVF is the OM flexible, and the not flexible GOT has the lower one, with ca. 7% point less.

As all the design decision the benefit can be monetised, in this dissertation the costs for support the renewable are considered.

The Open Market scheme has no costs for the consumers related to the output of the RES-E and the market price is not reduce therefore also the income of the conventional generators is not affected from this support scheme. Anyway, as explained in section 2, renewables have to be supported somehow for be competitive in the market, for example as is advise in (Boute A., 2012) the renewables could be supported with a capacity-based scheme. In the work at hand there are no possibilities to compare quantitatively the cost of the OM with the other schemes. The support level is not directly related to the revenues from the market therefore supporting the renewable on the installed capacity could easily leads to over-/under-compensations to the generators. This kind of remuneration has to include a high risk premium, because the generators are completely exposed to the market price fluctuation.

In the SP, FIT, and GOT the support of the renewables is based on the feed-in in the grid. The GOT is a feed-in tariff support mechanism where the generators gets a fix tariff for every energy unit in-feed in the grid, the generators also enjoy the “grid priority” therefore they are largely dispatched. The FIT scheme can be seen as a fixed premium scheme, where the generators earn a fixed premium on top of the market revenues. The premium that the generators earn is exactly as the tariff that the generators earn under the GOT scheme, but they have to participate in the market. The SP is a sliding premium scheme, means that the generator ´s premium is variable, and is varying according the market revenues of the renewable generators. Higher they are their revenues from the market lower is their support compensation.

The GOT and the FIT have the same cost for the consumers but the GOT permits less saving for the generators side cause of the lower average market price (higher merit-order effect). The savings for the generators side can be asses as difference on the annual average market price times the annual conventional generation. Under the FIT instead of the GOT scheme the savings for the conventional generators side, in the not flexible scenarios 2030, are ca. 400 millions of Euros higher.

The dynamic variability of the premium in the scenario permits savings for the consumers that can be asses as annual MV times the annual generation. In the scenario with 2030 as base year and the renewable can participate in the reserve market (flexible scenario), the MV reduces the costs for support the renewables of ca. 20 billions of Euros.

The possibility for the renewables to be completely integrated in the reserve market reduces the support cost for the consumers and increases the generator ´s savings. The savings that can be obtained without the interconnection with the reserve market are higher when the support scheme is less flexible. For instance the increase of the generators savings due to the flexibility of the reserve market in the SP scheme is ca. 700 millions of Euros whereas if the support scheme is the GOT than the savings is ca. 1 billion of Euros.

The SP permits higher annual average market price than the FIT and GOT, therefore higher conventional generator ´s savings. For instance the generator´s savings between the SP and GOT, in 2030 not flexible, are estimated to ca. 800 millions of Euros.

In summary, the results of this analysis suggest that the sliding-premium (SP) scheme has high potential. Compare to the GOT (feed-in tariff with grid priority) and FIT (“fixed premium”)

1. permits higher savings to both the consumers and conventional generators due to the variability of the premium, although it keep the income flow to the renewable generators constant;
2. As a more market-oriented support scheme permits less distortion on the development of the market prices (smaller merit-order effect);
3. Present higher flexibility in the periods of low residual demand;
4. The higher initially costs due to the management premium are estimate to be 2.7 billions of Euros[27], therefore are covers to the reduction of the support costs due to the variable premium.
5. Compared to the GOT the renewable generators under the FIT and the SP are active in the market to prevent the oversupply situations.

Compare to the OM (the renewables bid into the market at their marginal costs):

1. There is no metric parameters to compare the costs of the OM should be base on other parameters out of the market (i.e. capacity reward);

[27] The fixed management premium for the fluctuating technologies in 2013 was 12 €/MWh and 2.75 €/MWh for the non-fluctuating .The fixed part of the premium will decrease in the upcoming years due to learning effect of the market actors (Klobasa et al., 2013). But this value are used for a safer valuation.

2. In the OM the externalization from the market of the supports could make more difficult analyse the effectiveness of the scheme, and therefore lead to under-/over-compensation;
3. Furthermore the negative bid price of the variable renewable energies mirrors the social value given to the renewables coupled with the un-storability of the electricity, in this way there could be a economic-merit competition between the conventional plants that are unwilling to reduce their load due to technical constrains and the renewable supported by the society.

Moreover all the analysis show that the more flexibility due to the reserve market increase the total welfare. Although the technical problems to complete integrate the variable renewable energies in the reserve market due to their forecast issues, is seen important to integrate them at least in the secondary negative reserve. As a benchmark level for the variable renewable energies could be used the capacity credit. Furthermore the auctions for the energy reserves might be done more often in order to mitigate the uncertainty of the forecast.

Also the intraday market should increase their liquidity in order to reduce the balancing costs. The impacts of the renewable in the power market could also be mitigate also by expanding the European grid infrastructure, or increase the storage possibility.

A possibility for harmonizing the differences among the renewable energy sources, as constant and variable, could be to have different scheme per technology. For instance, the dispatchable generators could be directly marketed and they could be supported based on the capacity because they can react to the economic incentives as the conventional. Whereas for the fluctuating energies cannot react just to the economic incentives therefore they have to be supported based on the output. Furthermore the variability of the premium ensures to not give overcompensation.

6 Conclusions

6.1 Summary

Due to environmental and competitiveness reasons the European Union decided to support the RES. Since then, the share of renewable energy in the power market is steadily increasing.

Every European country has ambitious target to reach towards a low carbon economy. As the renewable energies in the market are in a not fair competition field, they have to be supported from the society in order to achieve the optimal level.

As hydro potential is almost exploited and biofuel-fired plants are limited by sustainability constraints much of the growth will need to come from wind and solar power, which are variable energy sources, in terms of output.

The penetration of the renewable energies has a strong impact on the power market, especially the variable energy sources. The main impacts of the renewable on the power market are the reduction of the average utilization of the conventional fleet, the future investments on conventional technologies, reduction of the average market price and increase the volatility of the spot market prices.

Since Germany has a thermal power system, as many other European countries, the integration of the renewable has even more severe impacts than countries with a high share of hydro power with possibility of storage the energy. Therefore Germany is considered a good research case for study the integration of the renewables.

The negative correlation of RES-E in-feed and the power prices have already been discussed in the literature, and this is known as merit-order effect. The volume of the merit-order effect is influenced by other factors as the CO_2 price, fuels cost, and the type of the conventional fleet.

Many mechanisms are suitable for support the renewables in the electricity market. In the literature seems that one of the important features of a support scheme is the compatibility with the liberalized market, the schemes more compatible are called market-oriented support schemes. The type of support mechanism influences the power market in two ways: different capacity installations, thus different renewable portfolios, and the way in which renewables participate in the electricity market. Recent studies analysed the impact due to different installation and contrary to the expectations the more market oriented scheme does necessarily have less impact on the market prices. To the author´s knowledge there is no quantitative studies about the impact on the market prices due to the bidding behaviour of the renewable energies, therefore is considered important to seek to fill the knowledge lack with an empirical study.

As power systems increase in complexity due to higher shares of intermitting RES-E, is also increasing the requirements for power system modeling. With Germany as example, this dissertation seeks to discuss to what degree the impact on the electricity price due to the increasing RES-E share could be mitigate with a more market oriented support scheme.

The support schemes analyzed were: the German market premium, the feed-in tariff scheme, fixed premium, and a scheme where the support to the renewables were not given from the output, therefore the renewable just bid their marginal costs.

6.2 Contributions

The results suggest that the sliding-premium scheme have high potential. Compared to the feed-in tariff and fixed premium permits to have higher savings to both the consumers and conventional generators, although it keeps the income flow to the renewable generators constant. The sliding-premium generates less distortion on the development of the market prices (smaller merit-order effect); and gives to market higher flexibility in the periods of oversupply. The main critic that is move to the sliding feed-in premium is the higher initial costs due to the management premium that has to be born from the consumers. The results show that the reduction of the costs for the scheme from the feed-in tariff or fixed premium is ca. 20 billions in 2030, whereas the evaluated cost for the management premium are approximately 2.7 billions of Euros.

For the comparison to the open market scheme there are no metric parameters in terms of costs. Anyway also in the open market scheme the renewable have to be support in other ways (i.e. capacity reward).

The externalization from the market of the supports cost could make more difficult analyse the effectiveness of the scheme, and therefore lead to under-/over-compensation due to the different revenues. As the “open market support scheme” permits higher consumer´s savings, because of the decrease of the merit-order effect and the absence negative bid, could be implemented a mixed support mechanisms where for the constant generators is reward the capacity and the fluctuating renewable energy are supported by the sliding premium.

Moreover, were analysed the effect on the spot market of the reserve market interconnection. The more flexibility due to the reserve market increases the total welfare and reduces the cost of the support scheme. Differently from the bidding behaviour of the renewable the higher flexibility due the reserve does not impact on the market prices just in the oversupply situations. The flexibility due to the reserve has higher effect on the short-run optimize system, because of the higher share of big base load plants in the conventional mix. Although the technical problems to completely integrate the variable renewable energies in the reserve market, due to their forecast issues, is seen important to integrate them at least in the secondary negative reserve. As a benchmark level for the variable renewable energies could be used i.e. the capacity credit. Furthermore the auctions for the energy reserves might be done more often in order to mitigate the uncertainty of the forecast. Also the intraday market should increase their liquidity in order to reduce the balancing costs. The impacts of the renewable in the power market could also be mitigate also by expanding the European grid infrastructure, or increase where is possible and economic the storage capacity.

From the author point of view is also important to notice that from the results is clear that higher is the flexibility of the residual system lower is the effect of the increasing flexibility due to the support mechanism or the reserve market. Nonetheless this consideration the power market has still to improve to integrate high share of intermittent renewable energy sources therefore every increase of flexibility is considered important.

6.3 Limitations of analysis

The assumption on the PowerACE model to real word situations in many ways, the most important are:

1. In the real word the demand is not completely traded in the spot market, in 2010 was 44.9% of the total(Winkler J., 2011);
2. There is no forecast errors in the generation of the renewable, as the hourly profile is input;
3. The market value for the calculations of the sliding premium bid is calculate with the forecast that are calculate with the GOT scheme- In this way the renewable generators expect lower income than what they will receive, therefore the bid is lower than how would be if the forecast would be calculate according the sliding premium mechanism.
4. For reasons of time were not carry out a sensitive analysis. For instance, could be assumed different fuels costs or weather conditions for assess the confidence of the results.

6.4 Future Work

The work for this analysis could be utilized in many other ways. The new part of the model was designed to be easily adapted to new bidding behaviour of the renewable. Furthermore the code is already operative for all Europe, therefore can be better carry out analysis about the harmonization of different support scheme across Europe.

As remembered in the limitations, the sliding premium model uses the forecast that is calculated by using the GOT to sell the RES-E generation. Therefore a future improvement could be to reiterate the program automatically and uses the result as a forecast. With this two mechanisms could be asses in what degrees the forecast errors of the renewable impact on the market prices.

With this new part could be test quantitative new parameters, i.e. the value of the feed-in tariff, in what degree they impact the market revenues of the renewable.

7 Appendix

Appendix 1: Definitions.

Term	Definition or Explanation
Biomass	In the simulations correspond to biomass, biogas, bioliquid and waste.
Biogas	In the simulations correspond to landfill gas, sewage gas, mine gas.
Residual Demand	The renewables are mostly dispatched, for their low variable costs and for the support policy designs. Moreover the VREs increase the fluctuation of the demand. Use the *residual demand*, calculate as total demand minus the RES-E dispatched, is useful to asses the challenges that has to face the conventional supply power system.
Levelized Costs of Energy (LCOE)	LCOE is determined by dividing the project's total cost of operation by the energy generated during the supposed life time of the plant. The total cost of operation should include all costs that the project incurs (including construction and operation). Incentives for project construction and energy generation can also be incorporated.

Dispatchable/constant renewable energy sources	Biofuel-fired plants, hydro power, and geothermal power are usually called dispatchable/constant renewable energy sources. For the biofuel and the geothermal is understandable why the input is considerable constant. For the hydro power the output depend on the seasonal water level in the rivers. However, an analysis of published data suggests that the market value of the hydro power can be assumed constant (Klobasa et al., 2013)

Appendix 2: FiT values.

Year	On shore wind	Off shore wind	Geo-thermal	Hydro	Biogas	PVR	PV	Bio-mass
	[€/MWh]	[€/MWh]	[€/MWh]	[€/MWh]	[€/MWh]	[€/MWh]	[€/MWh]	[€/MWh]
2000	91.01	91.01	80.53	73.20	72.72	506.18	506.18	176.10
2001	91.01	91.01	80.53	72.90	72.72	506.18	506.18	180.97
2002	91.01	91.01	80.53	72.68	72.72	480.87	480.87	178.32
2003	91.01	91.01	80.53	72.83	72.72	456.84	456.84	170.14
2004	87.00	91.00	115.03	77.02	68.42	563.79	457.00	88.09
2005	85.30	91.00	115.03	77.96	66.59	533.69	434.15	91.34
2006	83.60	91.00	115.03	84.29	65.59	505.89	405.93	89.97
2007	81.90	91.00	115.03	75.90	64.61	478.67	379.54	89.04
2008	80.30	89.20	115.03	82.77	63.64	454.66	354.87	86.30
2009	92.00	150.00	132.50	87.38	66.02	412.47	324.70	87.67
2010	91.08	150.00	131.18	69.23	65.47	344.47	269.83	88.57
2011	90.17	150.00	129.87	91.84	64.93	271.65	213.35	87.50
2012	89.30	190.00	250.00	94.94	63.08	189.32	143.22	203.96
2013	87.96	190.00	250.00	81.21	62.13	142.95	106.39	199.88
2014	89.00	194.00	252.00	81.58	60.73	119.37	94.70	129.41
2015	89.00	194.00	252.00	81.58	60.04	115.64	90.47	129.41
2016	88.64	194.00	239.40	81.17	59.14	108.89	85.19	128.76
2017	87.23	194.00	227.43	80.76	58.26	102.54	80.21	126.21
2018	85.85	194.00	216.06	80.36	57.38	96.55	75.53	123.70
2019	84.48	194.00	205.26	79.96	56.52	90.91	71.12	121.25
2020	83.14	154.00	194.99	79.56	55.67	85.61	66.97	118.84

Source: See section 3

Appendix 3: Renewable Capacity used for the simulations.

	Hydro Power	**On shore wind**	**Off shore wind**	**PVR**	**PV**	**Geothermal**	**Biogas**	**Biomass**
	[MW]	[MW]	[MW]	[MW]	[MW]	[MW]	[MW]	[MW]
1990	3982	55	0	2	0	0	64	615
1991	4033	106	0	2	0	0	69	616
1992	4049	174	0	6	0	0	72	617
1993	4117	326	0	9	0	0	99	639
1994	4211	618	0	12	0	0	124	583
1995	4348	1121	0	18	0	0	138	598
1996	4305	1549	0	28	0	0	153	659
1997	4296	2089	0	26	16	0	167	661
1998	4369	2877	0	54	0	0	283	718
1999	4547	4435	0	70	0	0	305	798
2000	4831	6097	0	114	0	0	321	967
2001	4831	8738	0	176	0	0	327	1085
2002	4937	11976	0	296	0	0	341	1274
2003	4953	14593	0	435	0	0	361	1969
2004	5186	16612	0	824	281	0	397	2233
2005	5210	18375	0	1567	489	0	409	3117
2006	5193	20568	0	2270	629	0	422	3861
2007	5137	22183	0	2772	1398	3	434	4289
2008	5164	23815	0	4101	2019	3	446	4810
2009	5340	25632	60	5615	4951	8	456	5539
2010	5407	27012	168	9372	8163	8	432	6167
2011	5625	28857	203	13360	11679	8	367	6781
2012	5607	30996	308	15510	17133	12	354	7183
2013	5613	33757	903	17080	18868	31	350	7736
2014	5611	36257	1787	18268	20180	48	373	7836
2015	5676	38757	2570	19456	21492	70	384	7936
2016	5740	41257	3354	20644	22804	98	396	8036
2017	5804	43757	4137	21832	24116	133	408	8136
2018	5869	46257	4921	23020	25428	176	420	8236
2019	5933	48757	5704	24207	26741	227	431	8336
2020	5997	51257	6500	24707	27293	289	443	8436
2021	6062	53757	7350	24707	27293	289	455	8536
2022	6126	56257	8200	24707	27293	289	466	8636
2023	6190	58757	9050	24707	27293	289	478	8736
2024	6255	61257	9900	24707	27293	289	490	8836

2025	6319	63757	10750	24707	27293	289	501	8936
2026	6383	66257	11600	24707	27293	289	513	9036
2027	6448	68757	12450	24707	27293	289	525	9136
2028	6512	71257	13300	24707	27293	289	537	9236
2029	6576	73757	14150	24707	27293	289	548	9336
2030	6641	76257	15000	24707	27293	289	560	9436

Source: Own illustration and calculation. Historical data from 1990 to 2013 retrieved from (AGEE stat, 2014) based on (BMWi, 2014).

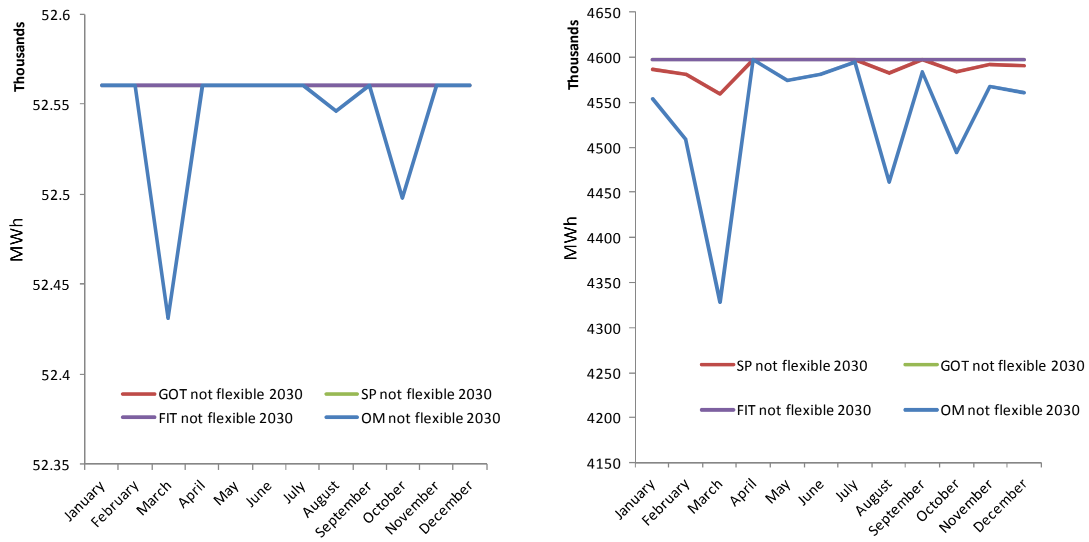
Appendix 4: Renewable generation used for the simulations.

	Hydro	**On shore wind**	**Off shore wind**	**PVR**	**PV**	**Geothermal**	**Biogas**	**Biomass**
	[GWh]	[GWh]	[GWh]	[GWh]	[GWh]	[GWh]	[GWh]	[GWh]
1990	14910	71	0	1	0	0	217	1218
1991	12627	100	0	1	0	0	249	1222
1992	14733	275	0	4	0	0	279	1279
1993	15179	600	0	3	0	0	396	1239
1994	16951	909	0	7	0	0	512	1363
1995	18671	1500	0	7	0	0	559	1451
1996	18729	2032	0	12	0	0	606	1492
1997	14845	2966	0	11	7	0	653	1620
1998	14760	4489	0	35	0	0	1310	1946
1999	16881	5528	0	30	0	0	1454	2131
2000	18828	9513	0	60	0	0	1517	3214
2001	19749	10509	0	76	0	0	1483	3731
2002	20096	15786	0	162	0	0	1548	4500
2003	15087	18713	0	313	0	0	1748	7093
2004	16909	25509	0	416	141	0	1974	8497
2005	16276	27229	0	977	305	0	2164	12190
2006	16574	30710	0	1738	482	0	2149	16551
2007	17566	39713	0	2044	1031	0	2042	22321
2008	16961	40574	0	2962	1458	18	1958	25834
2009	15886	38610	38	3498	3085	19	1919	28659
2010	17265	37619	174	6262	5454	28	1877	32430
2011	14659	48315	568	10458	9141	19	1908	35695
2012	18036	49948	722	12534	13846	25	1852	42781
2013	17596	52430	970	14254	15746	40	1820	46080
2014	20510	58086	2794	14217	15705	104	1938	45816

2015	20763	62523	4025	15432	17047	152	1999	46401
2016	21016	67015	5260	16682	18428	213	2060	46986
2017	21268	71564	6499	17968	19848	289	2121	47570
2018	21520	76167	7742	19289	21307	382	2182	48155
2019	21772	80827	8989	20645	22806	493	2243	48740
2020	22023	85542	10259	21440	23684	628	2304	49324
2021	22274	90313	11619	21809	24091	628	2364	49909
2022	22525	95140	12983	22178	24499	628	2425	50494
2023	22775	100022	14351	22547	24906	628	2486	51078
2024	23025	104960	15723	22915	25313	628	2547	51663
2025	23275	109954	17100	23284	25721	628	2608	52248
2026	23524	115003	18481	23653	26128	628	2669	52832
2027	23773	120108	19866	24022	26535	628	2729	53417
2028	24022	125269	21255	24390	26943	628	2790	54002
2029	24270	130485	22648	24759	27350	628	2851	54587
2030	24518	135757	24046	25128	27757	628	2912	55171

Source: Own illustration and calculation. Historical data from 1990 to 2013 retrieved from (AGEE stat, 2014) based on (BMWi, 2014).

Appendix 5: Monthly generation of the Biomass (right) and Geothermal power (left).



Source: Own Calculation. Data obtained with PowerACE model.

Appendix 6: Generation outlook in the hour within is reach the minimum price for the not flexible scenario in year 2020 and FIT support scheme

Technology	Generation [MWh]
Hour	2148
Biogas	24
Biomass	5631
Demand	-60358
Gas	0
Geothermal	72
Hard Coal	4823
Hydro Power	2423
Lignite	4918
Import/Export	-4296
Nuclear	0
Oil	0
PVR	14443
Pump Storage	-8996
PV	15632
Waste	0
Off shore wind	2825
On shore wind	22860

Source: PowerACE model.

Appendix 7: Generation outlook in the hours within is reach the minimum price for the not flexible scenario in year 2020 and SP support scheme

Technology	Generation [MWh]	
Hour	2148	2149
Biogas	0	0
Biomass	5631	5631
Demand	-60358	-58656
Gas	0	0
Geothermal	72	72
Hard Coal	4823	4823
Hydro Power	2124	2337
Lignite	4918	4918
Import/Export	-4296	-4394
Nuclear	0	0

Oil	0	0
PVR	14443	13488
Pump Storage	-8996	-8996
PV	15955	14900
Waste	0	0
Off shore wind	2825	2906
On shore wind	22860	22971

Source: PowerACE model.

Appendix 8: Generation outlook in the hours within is reach the minimum price for the not flexible scenario in year 2020 and no support scheme for the RES (OM).

Technology	**Generation [MWh]**	
Hour	2148	2149
Biogas	144	192
Biomass	4073	4239
Demand	-60358	-58656
Gas	0	0
Geothermal	72	72
Hard Coal	4823	4823
Hydro Power	2514	2514
Lignite	4918	4918
Import/Export	-4296	-4394
Nuclear	0	0
Oil	0	0
PVR	14443	13488
Pump Storage	-8996	-8996
PV	15955	14900
Waste	1023	1023
Off shore wind	2825	2906
On shore wind	22860	22971

Appendix 9: Bidding behaviour algorithm for the RE bidder that bid directly in the Open Market.

```
private void generateOMBid(int h,RenewableTechnology rTech,int year){
    price=rTech.mc.get(DateManager.getCurrentYear());
    volume=-rTech.loadProfile.get(year)[24*(getCurrentDayOfYear(h)-
    1)+h];
}
```

Source: Own Research.

Appendix 10: Bidding behaviour algorithm for the RE bidder supported by the Feed in Tariff mechanism.

```
private void generateFITBid(int h,RenewableTechnology rTech,Integer
year){
if (!(rTech.FiT.get(year) == 0)) {
    price = rTech.FiT.get(year);
    } else {
        price = rTech.mc.get(DateManager.getCurrentYear());
    }
    price = -price;
    volume = -rTech.loadProfile.get(year)[24*(getCurrentDayOfYear(h)-
    1)+h];
}
```

Source: Own Research.

Appendix 11: Bidding behaviour algorithm for the RE bidder supported by the Sliding Premium mechanism.

```
private void generateSPBid(int h,RenewableTechnology rTech,Region
region,Integer year){
    if(!(rTech.FiT.get(year)==0)){
     price=(float)(rTech.FiT.get(year)-
    (monthlyAvarageMarketPricesForecast.get(region)*
    *relativeMarketValue.get(region).get(rTech)));
   }else{
     price = rTech.mc.get(DateManager.getCurrentYear());
   }
   price=-price;
   price=rTech.mc.get(DateManager.getCurrentYear())+price;
   volume=-Tech.loadProfile.get(year)[24*(getCurrentDayOfYear(h)-1)+h];
}
```

Source: Own Research.

Appendix 12: PowerACE ´s method that generate the hourly bid from the renewable generators according their bidding behaviour

```
public ArrayList<BidPoint> callForBidsSpot(){
    hBids.clear ();
    for (int h = 0; h < 24; h++) {
        for(Region region:DataManagerRegions.scenarioRegions.values()){
            if (region.supportSchemeType.toLowerCase().equals("sp")){
                generateMonthlyForecastBaseYear (h);
```

```
            }
            for(RenewableTechnology
            rTech:region.renewableTechnologies.values()){
                for (Integer
                year:rTech.installedCapacityPerYear.keySet()){
                hBids.add(generateHBid(h, region, rTech, year));
                }
            }
        }
    }
return hBids;
}
```

Source: Own Research.

Appendix 13: PowerACE´s Method for generate the installed capacity per year profile from the total capacity profile.

```
public static void splitCapacityboolean isRefill) {
    for (Region region:DataManagerRegions.scenarioRegions.values()){
        for (RenewableTechnology
        rTech:region.renewableTechnologies.values()){
            HashMap<Integer,Float>installedCapacity=new
            HashMap<Integer,Float>();
            int firstYear=java.util.Collections.min(
            rTech.installedCapacityPerYear.keySet());
            float control = 0f;
            installedCapacity.put(firstYear,
            rTech.installedCapacityPerYear.get(firstYear));
            for(int year=firstYear+1;
            year<=DateManager.getCurrentYear();year++){
                installedCapacity.put(year,0f);
                int lastYear = (year - 1);
                //check if, in order to not have negative installed
                // capacity per year
                if((rTech.installedCapacityPerYear.get(year)-
                rTech.installedCapacityPerYear.get((lastYear)) < 0)) {
                //some plants were shut off.
                    float debt=
                    rTech.installedCapacityPerYear.get(year)-
                    rTech.installedCapacityPerYear.get((lastYear));
                    installedCapacity.put(year, 0f);
                    //Hp: here is assumed the order”first in first out”
                    //of the “power plants”
                    int anno = firstYear;
                        while (debt < 0 && anno < year) {
                            if ((installedCapacity.get(anno) + debt)<0){
                                debt += installedCapacity.get(anno);
                                installedCapacity.put(anno, 0f);
                            } else {
                                installedCapacity.put(
                            anno,installedCapacity.get(anno)+debt);
                            debt = 0;
                            }
                        anno++;
                        }
```

```
                    installedCapacity.put(
                    year,(rTech.installedCapacityPerYear.get(year)-
                    rTech.installedCapacityPerYear.get((lastYear))));
                }
            //update installedCapacityPerYear
            for (int year=firstYear;
            year<=DateManager.getCurrentYear();year++){
                rTech.installedCapacityPerYear.put(
                year,installedCapacity.get(year));
            }
        }
    }
}
```

Source: Own Research.

Appendix 14: PowerACE´s Method that readapt the installed capacity per year with the assumed life time of the plants (20 years).

```
public static void fixLifeTime() {
    for (Region region : DataManagerRegions.scenarioRegions.values()) {
        for (RenewableTechnology
        rTech:region.renewableTechnologies.values()) {
            float control = 0;
            int firstYear=
            java.util.Collections.min(
            rTech.installedCapacityPerYear.keySet());
            if (firstYear<(DateManager.getCurrentYear()-20)){
                for(int year=firstYear;
                year<=(DateManager.getCurrentYear()-20);
                year++){
                    float newCapacity=
                    rTech.installedCapacityPerYear.get(year)+
                    rTech.installedCapacityPerYear.get(year+20);
                    rTech.installedCapacityPerYear.put(
                    (year+20),newCapacity);
                    rTech.installedCapacityPerYear.remove(year);
                }
            }
        }
    }
}
```

Source: Own research.

Appendix 15: PowerACE´s method for generate the hourly generation per every year from the total generation.

```
public static void calculateAnnualRenewableLoad() {
        DecimalFormat small = new DecimalFormat("##.0000");
        DecimalFormat big = new DecimalFormat("##");
        for (Region
         region:DataManagerRegions.scenarioRegions.values()){
            for (RenewableTechnology
            rTech:region.renewableTechnologies.values()) {
                rTech.loadProfile = new HashMap<Integer, Float[]>();
```

```
                for (int year:rTech.installedCapacityPerYear.keySet(){
                    Float[]array=new Float
                    [DateManager.getInstance().hoursInCurrentYear];
                    Arrays.fill(array, 0f);
                    rTech.loadProfile.put(year, new
                   Float[DateManager.getInstance().hoursInCurrentYear]);
                    rTech.loadProfile.put(year, array);
                    if (!(rTech.installedCapacity == 0)) {
                        double annualCoefficent =
                        rTech.installedCapacityPerYear.get(year) /
                        rTech.installedCapacity;
                        for (int h=0;
                        h<DateManager.getInstance().hoursInCurrentYear;
                        h++) {
                            rTech.totalLoadProfile[h] =
                            rTech.normalizedLoadProfile[h] *
                            rTech.generation;
                            array[h]=(float)(annualCoefficent*
                            rTech.totalLoadProfile[h]);
                        }
                    }
                    rTech.loadProfile.put(year, array);
                }// years loop
                if (!(rTech.installedCapacity == 0)) {
            }//tech loop
        }
    }
```

Source: Own Research.

Appendix 16: PowerACE method, generateHbid.

```
private BidPoint generateHBid(int h, Region region, RenewableTechnol-
ogy rTech, int year) {
        if (region.supportSchemeType == "") {
            sysLog.warn("The scenario does not consider any support
scheme thus the RES-load is sell in the open market at the marginal
cost  ");
            generateOMBid(h, rTech, year);
        } else {
            switch (region.supportSchemeType.toLowerCase()) {
            //          Feed-in Tariff scheme
            case "fit":
                generateFITBid(h, rTech, year);
                break;
            case "om":
                generateOMBid(h, rTech, year);
                break;
            //          Fixed premium scheme
            case "fp":
                generateFPBid(h, rTech, year);
                break;
            //          Sliding Premium
            case "sp":
                generateSPBid(h, rTech, region, year);
                break;
```

```
        //          Open Market scheme
        default:
            generateOMBid(h, rTech, year);
            break;
        }
    }
    Integer anno = new Integer(year);
    Object bidderAgent = new String(rTech.name.toString() +
    " ,year of construction " + anno.toString());
    return new BidPointSupply((byte) h, price, volume, region, bid-
    derAgent);

}
```

Source: Own Research.

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