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The Impact of RES-E Policy Setting on Integration Effects - A Detailed Analysis of Capacity Expansion and Dispatch Results

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Abstract

The operation of the power markets is strongly affected by the presence of high shares of electricity from renewable energy sources (RES-E) in the market. Especially in times of high RES-E infeed, firm market situations can lead to extreme results, even to negative power prices. The behavior of RES-E in potential oversupply situations depends on the RES-E support scheme and in particular on the defined curtailment rules. By now, different curtailment rules have not been taken into account in long-run capacity expansion analyses. The present research investigates the impact of curtailment rules on the operation and the investment decisions through the utilization of "The High Temporal Resolution Electricity Market Analysis Model" (THEA) for the German power market under consideration of the neighboring countries. In general the results show that RES-E can provide flexibility to the system if low burdens for curtailment are applied. This comes with the cost of lacking market signals which could trigger investments in flexible generation capacities. However, if RES-E are forced into the market at any cost, the burden for consumers increases and the market signals high demand for alternative flexibilities.

Keywords: Power market modeling, RES-E integration, curtailment rules

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1 Introduction

The promotion of electricity from renewable energy sources (RES-E) in Germany began in the early 1990s. Since 2000, the deployment of RES-E capacities has grown considerably due to the renewable energy sources act (EEG). In 2009, 16.1% of the gross electricity production stemmed from renewable energy sources (RES) of which 6.5% from wind power alone (BMU, 2010a). With a total installed capacity of 25.8 GW at the end of 2009, Germany is the largest wind power market in Europe, in absolute terms.

Since most RES-E technologies are not able to compete in the power market, additional financial support is required to trigger investments. The EEG is a feed-in tariff system (FIT), which remunerates each renewable generated energy unit fed into the grid. The rapid increase of the RES-E share can be attributed to this low risk investment scheme. One crucial support scheme design element is the obligation for the transmission system operators (TSOs) to integrate each generated RES-E unit into the market independent of the actual demand.

The remaining power market faces increasing challenges to integrate the growing RES-E share due to the intermitting nature of wind and solar irradiation. Since each RES-E unit has to be integrated, the conventional side of the power market has to provide the flexibility to adjust itself to the fluctuating residual demand. Throughout the entire article, the residual demand perspective is applied, since the later analysis focuses on the optimization of the conventional supply side. Consequently, RES-E is seen as a part of the demand side, which also bears the support costs. The integration challenges for the supply side can be translated into requirements for the long-run development of the electricity market. Besides the technical challenges of following the fluctuations, the economics of the power market are also challenged. Since an increasing share of the demand is met by out-of-market supported RES-E, the remaining power market faces different requirements, which in the long-run lead to adaptations of the generating capacity. In order to enable the analysis of the new challenges for the power market, the requirements in electricity market modeling also need to mirror mirror the additional complexity. Therefore, 'The High Temporal Resolution Electricity Market Analysis Model' (THEA) has been developed, which takes these additional requirements, in particular the increased temporal resolution, into account. This model is tested in Nicolosi et al. (2010) against other approaches found in the literature to illustrate the importance of high temporal resolution in modeling high RES-E penetration scenarios. This article focuses on the German power market, but takes the surrounding interconnected markets into account as well. The analysis concentrates on the impact of various policy options on the ability to integrate RES-E into the power market. In order to analyze the effects of different RES-E support schemes and their corresponding curtailment rules in the long-run, four different policy scenarios are calculated.

The article is structured as follows. The next chapter provides the motivation and an overview of the literature. Section 3 discusses the applied methodology. Section 4 provides the input assumptions, scenario definition and the results. Finally, section 5 discusses the results, identifies further research potential and concludes the analysis.

2 Motivation and Literature Review

This chapter motivates the research, provides a brief overview of literature on RES-E market integration and identifies gaps, which are filled by the analysis presented in this article. First, the short-term market effects are explained and discussed. Second, long-run market adaptations, which project the short-term effects into the longer term, are discussed.

2.1 Short-Term Effects

Wholesale power prices tend to be lower in hours with high RES-E infeed because the lower residual demand can be met by cheaper marginal units (see e.g. Neubarth et al. (2006), Bode and Groscurth (2006), Sensfuss et al. (2008) and Wissen and Nicolosi (2008) for a discussion on these wholesale power price reducing effects in Germany, Munksgaard and Morthorst (2008) for Denmark and Miera et al. (2008) for Spain). The literature is divided in two methodological streams. Early analyses are mainly based on empirical analysis and the later research is mainly based on dispatch computer model applications. This article adds the investment perspective under consideration of different curtailment policies to the discussion and includes the possibility of international exchange. The following research questions are analyzed in this article:

- How does the power price evolve with an increasing RES-E share over time?
- How does this influence the value of RES-E and consequently the support costs for the consumers?
- How does the power market adapt to the increasing RES-E share?
- Which market design options enable the further integration of increasing RES-E shares?

The analysis assumes a competitive power market in order to isolate the fundamental drivers of the price effects without stipulating additional assumptions on market power behavior. One motivation for the detailed analysis of RES-E curtailment policies are the findings of Nicolosi (2010) who discusses the significant negative power prices in oversupply situations due to the preferential infeed within the German FIT. It has been shown that due to the infeed obligation of the FIT, power prices decreased as low as -500 EUR/MWh. By now, curtailment rules have been included in the regulatory framework to avoid such dramatic price drops. Other RES-E support schemes do not require an exogenously defined curtailment rule but follow an intrinsic logic which triggers curtailment due to economic considerations of the RES-E plant operator. To show the intrinsic characteristics of an alternative RES-E support scheme, Figure 1 shows the price effects in the ERCOT power market in Texas where the federal 'Production Tax Credit (PTC) acts as fixed premium payment to support RES-E.

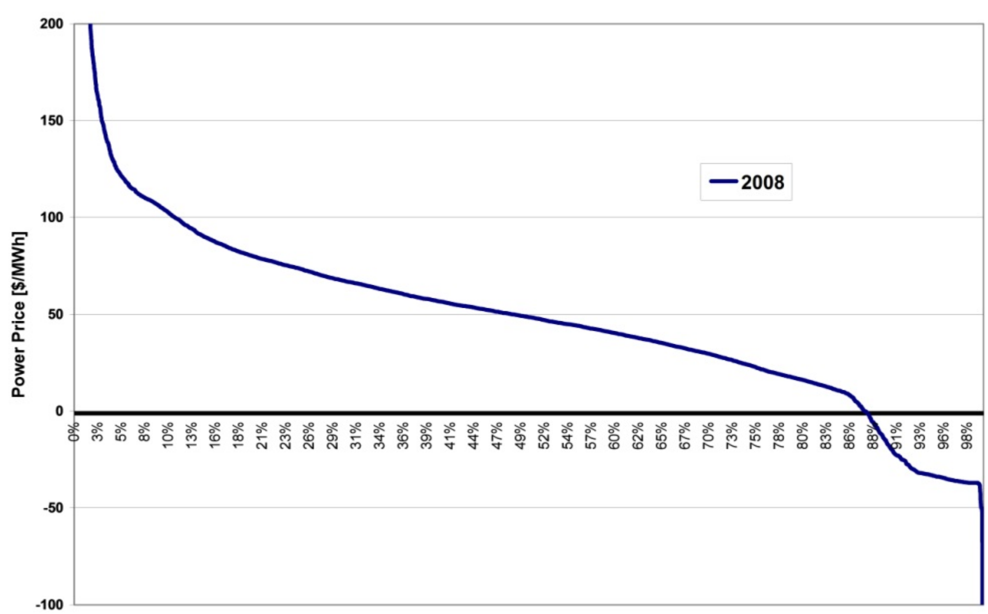

Figure 1: Price duration curve in Western Texas in 2008, source: author, data provided by ERCOT (2010)

By the negative price convergence at roughly -35 USD/MWh, it can be seen that the curtailment decision reflects the level of the premium payment. As long as the power price is above the negative value of the premium, the income for the wind generator is still positive (i.e. if the premium is 30 EUR/MWh and the power price is -20 EUR/MWh, the profit is still 10 EUR/MWh). If the power price drops below this level, the operator curtails the wind energy due to economic reasons. This short-term observation has also effects in the long-run for the investment decision generating capacities. Wissen and Nicolosi (2008) and Miera et al. (2008) started discussions on capacity adaptation within this context, but mainly on a qualitative level. However, in order to assess the economic implications of the RES-E market value, a long-run perspective is required, which takes system adaptations into account. Understanding the short term effects is nevertheless of fundamental importance for the analysis. Hence, the fundamental dispatch structure and the resulting market prices are of particular interest. Therefore, in this article, the short-term effects are put into context by analyzing dispatch and prices on the basis of a capacity portfolio optimized over time. Consequently, an overview on research concerning long-run capacity development is provided in the following.

2.2 Long-Term Effects

Deriving an economic value of RES-E for a power system solely based on the static perspective of a dispatch model or empirical data is not sufficient since the evolution of RES-E includes by definition the long-term perspective of investment decisions. Consequently, capacity adaptations of the remaining system have to be included in the analysis as well as done by e.g. Dena (2005) and Decarolis and Keith (2006) with different simplifications. The dynamic process in which new power plant investment decisions are considered is critical in modeling the impact of RES-E on the power system. The particular context defines the required attributes of the capacity mix. In any case, the generating capacity has to be sufficient to guarantee a reliable operation of the system. The terminology of the reliability problem follows roughly Batlle et al. (2007), who distinguish between security, firmness and adequacy:

- Security is understood to be the readiness of existing generating capacity to respond, when needed, to meet the actual load. This means that the capacity is capable of following the load pattern.
- Firmness is defined to be the short-term generating availability resulting from the operational scheduling of installed capacity. This definition is modified to incorporate the ability to provide sufficient reserve capacity and energy at the same time. If the market is firm at a certain point, opportunity costs influence the pricing mechanism. In the context of this article, this is especially important in low demand situations.
- Adequacy means the existence of sufficient available installed capacity to meet demand at any time.

Despite the interrelation between short-term dispatch results and longer-term investment decisions, modeling the combined impact of both effects has proven challenging. Two general research streams exist in the literature, pure dispatch approaches and investment and dispatch problems which usually apply a reduced temporal resolution. NREL (2008), Pehnt et al. (2008) and Dena (2010) analyze RES-E penetration effects with a temporal resolution of 16, 144 and 288 load levels respectively. Nicolosi et al. (2010) show the importance of modeling with high temporal resolution of 8760 hours in high RES-E penetration power markets. The analysis in this article is based on the same methodological approach and assesses the long-run effects of different RES-E policies on the market development. The particular focus lies on the capacity adaptation and dispatch behavior under the assumption of different curtailment rules for RES-E. Besides the conventional market results, one of the main outputs are the wholesale market values of different RES-E technologies.

3 The High Temporal Resolution Electricity Market Analysis Model

This section explains the basic methodology, which enables 'The High Temporal Resolution Electricity Market Analysis Model' (THEA) to calculate the impact of RES-E on the capacity mix in high temporal resolution. The section is structured as follows: First, the general structure of Benders Decomposition is explained in a simplified manner. Second, the modeling framework of THEA is explained in a qualitative way to provide an intuitive understanding of the methodology. A detailed technical model description can be found in Nicolosi (forthcoming).

To allow efficient solutions to the dispatch and capacity expansion problem in a high temporal resolution of 8760 hours per year, an approach that was first presented by Benders (1962), and is known as 'Benders Decomposition', is implemented. Based on the duality theory, large mathematical problems can be decomposed into smaller problems by fixing the complicating variable in the subproblem (SP) and optimizing it in the master problem (MP) through an iterative algorithm that converges when an optimal solution is reached. Cote and Laughton (1979) presented an initial application of Benders Decomposition to power system optimization and proved its advantages for a simple investment and operation problem in terms of memory requirements and solution times.

THEA is a linear optimization dispatch and investment model. Investment decisions are computed in 5-year steps up to 2070, which enables an economic interpretation until 2030 due to long lifetimes of the investments. THEA's main advantage is a high resolution investment decision based on a full dispatch year. Not only considers the investment decision all extreme situations of one year, but the dispatch part of the model provides information on part-load and start-up costs based on a full year allowing for a detailed analysis of typical as well as extreme contiguous time frames. The investment decisions in the MP are optimized according to the results from the dispatch part of the model, which provides information on efficient capacity adaptations in form of duals of the capacity restriction. This investment decision is updated in every iteration according to the SP results until the predefined convergence criterion is fulfilled.

The hourly dispatch considers fuel-type and vintage fleet capacities in order to keep the problem linear (i.e., the model considers all CCGTs within one vintage class as a single unit, and therefore does not evaluate distinct individual plants). All considered technologies in THEA are distinguished between endogenous and exogenous investment possibilities. For endogenous investments, the investment costs are annualized according to a predefined depreciation time and interest rate. The age structure of the existing fleet is mirrored by vintage classes, which take technology developments into account (e.g. increasing efficiency). The coal fleet has six different vintage classes, the CCGT fleet four, the OCGT fleet three and the nuclear fleet two. Existing hydro power capacities and exogenous investments are also included, but new endogenous investments are not possible due to natural resource restrictions. In each modeled year, the gap between incumbent generation capacity and the peak load requirement has to be met by endogenous investments.

In the dispatch problem, THEA optimizes the dispatch of the installed conventional capacities, according to the residual load. Hereby, start-up cost and part-load losses are considered. Additionally, technical ramping constraints are taken into account limiting extreme ramp-ups for individual technologies. The ramping is further limited by minimum load restrictions. Spinning and non-spinning reserve requirements constitute further restrictions to the dispatch problem. In times of high RES-E infeed and low load, the minimum load limitations in combination with reserve requirements force the dispatch solution into extreme situations. To enable the match of supply and demand, RES-E curtailment options are implemented (the curtailment scenarios are explained in detail in the later scenario definition. Since RES-E receive market independent support, the curtailment option is only chosen if no cheaper way is feasible. In the case of oversupply, the typical 'first choice' flexibility is the international exchange between market zones. This exchange is limited by exogenously provided net transfer capacities (NTC) and causes transmission losses. Further flexibilities on the demand and the supply side are storage technologies. In situations of oversupply, storage technologies increase the demand and store energy for high demand hours. In these high demand hours, the storage technologies are part of the supply side and reduce the demand for expensive peaking units. While the capacities of pumped-hydro storage are exogenously provided, compressed air energy storage (CAES) can also be commissioned endogenously.

Since OCGT is the only thermal technology that is able to start-up within 15 minutes, it is also able to provide tertiary reserve without being ramped-up while other technologies need to operate in partload. Therefore, the 'superpeaker' technology can be interpreted as long-term system security investment or capacity adequacy solution, OCGT investments can be interpreted as requirement for the quality of the capacity. The load and the RES-E structure are provided exogenously and are based on historic data. Combined with annual load and RES-E targets for each year, the residual load is computed as well as the required installed RES-E capacities. Since the curtailment per technology is limited by the total infeed of this particular technology, the individual RES-E infeed needs to be implemented in the dispatch problem as well. Other exogenous parameters are the availability of plants and the hydro inflow into the reservoirs.

To enable the computation of this complex problem in an iterative manner, THEA adds one additional tool from recent high-performance-computing (HPC) developments: the dispatch is calculated in a monthly decomposed parallel mode (see Figure 2 for a visualization of this approach within the Benders Algorithm). The advantage of this latter approach is that while a global model utilizes only one processor core, THEA uses all available cores of the modeling server in the SP. In this way, the IT infrastructure can be utilized more efficiently and the overall solution time is reduced substantially.

The main outputs of THEA are the technology choices of the investment decision in the MP and the generation mix of the SP. These outcomes show on an aggregated level, how the market reacts to the increasing penetration of RES-E. These results come with the underlying investment and generation costs. A further dispatch outcome is the international exchange and the price level. Thereby, the main advantage of THEA is the greater temporal detail of these results which are available for every hour of the year. Especially the extreme hours can be analyzed in detail this way.

The basic steps in the dispatch and capacity expansion problem solved by THEA are presented in Figure 2. First, the initial capacity of the power system is calculated in the master problem (MP), representing a mix of existing incumbent generation capacity as well as any new installations that are required to fulfill the power systems' overall capacity requirements. Any new installations required to meet overall capacity obligations under these initial conditions are chosen based on a least cost algorithm, in the first iteration, not considering the dispatch problem. Second, this initial generation capacity mix is passed on to the dispatch part of THEA, the subproblem (SP). The total dispatch costs that come from the SP as well as the capacity duals are then passed on to the convergence check in the third step. Here, the algorithm measures the relative cost difference between the lower bound (LB) and the upper bound (UB).

The lower bound is the target function of the master problem whereas the upper bound is derived from the dispatch cost of the SP and additional cost factors from the MP. Since the initial MP has only information on investment costs, and not on the inefficiency of the dispatch problem that comes from fuel, start-up and part-load costs as well as reserve requirements, there is no possibility that the algorithm can converge after only one dispatch run. Since the algorithm does not converge in the third step, in the fourth step, the full MP receives the dispatch costs as well as the capacity duals. The so called Benders Cut then calculates the change in the capacity mix that leads to a lower cost

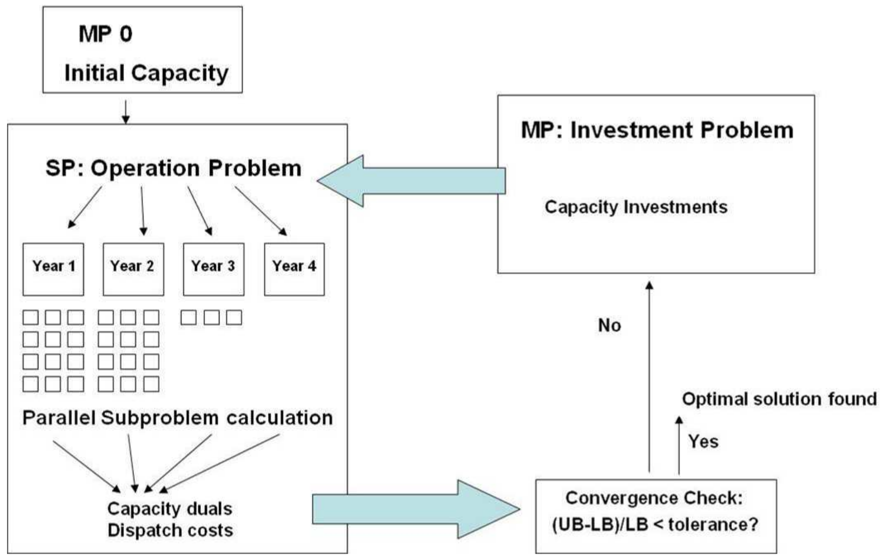

Figure 2: Benders structure with parallelization, source: author

solution on the basis of the capacity duals, which are calculated in the SP and passed on to the MP. In every iteration, one additional Benders' Cut is added to further constrain the solution space. This new capacity mix is then again passed on to the SP and the algorithm continues. If the solution is within the predefined cost tolerance (in this article 0.0001), the algorithm converges with the optimal solution.

One particular strength of THEA is the high resolution price information. Under the assumption of perfect competition and foresight of a well informed benevolent planner, the investment and dispatch costs are minimized. In contrast, global investment and dispatch models follow a different logic when it comes to the interpretation of the marginals of the energy market constraint (see e.g Bartels (2009) for an example of a complex global investment and dispatch model). In a global model, the marginal value in peak hours also reflects the investment costs that are required to fulfill the demand constraint, since all constraints are optimized simultaneously. Therefore, the marginals can only be interpreted as long-run marginal costs, which by definition increase as soon as investments are required. Thereby, long-run marginal costs follow the logic of the peak-load pricing model, but are not necessarily the market results of a market under perfect competition. This is due to the fact, that once investments are undertaken, the bidding process does not take fixed costs into account, but treats them as sunk. In an oligopolistic market structure, companies could influence the market results to cover the investment costs. This however deviates from the assumption of perfect competition which is chosen here to address the fundamental effects of high RES-E penetration independent from ownership assumptions. One additional weakness of the peak-load pricing approach is the arbitrary starting-point. All investments that are undertaken previously to the starting year are not reflected by the marginals of the energy market constraint, future investments however are taken into account. If one would interpret long-run marginal costs of global investment and dispatch models, one could understand those as required price level to cover the required investments, but not as competitive market prices. THEA treats all investment decisions as sunk costs. This approach ensures that the marginals of the energy market constraint can be interpreted as short-run marginal costs or as market prices in a competitive market.

4 The Impact of RES-E Policies on the Market Development

In this section the impact of the RES-E targets until 2030 are analyzed under consideration of the surrounding markets. The ambitious RES-E targets have strong effects on all system components. To get better insight into the dynamics of the power market with increasingly high RES-E shares, the focus is laid on the effects on the RES-E value and on the conventional supply side consisting of different technology types. The demand side is considered by taking into account the financial burden which stems from energy and reserve markets as well as from exogenously applied RES-E support payments.

The next subsection provides an overview of the input assumptions followed by a scenario definition. The remaining part of this section discusses model results, which provide insight into the market adaptation and behavior due to the German RES-E targets, and analyze how the particular curtailment rules affect different market components.

4.1 Input Overview

In order to enable a feasible computation time and at the same time to capture important market interaction features, the modeled power system is limited to 11 zones. The markets which have a direct interconnection with Germany (Denmark, Poland, Czech Republic, Austria, Switzerland, France and the Netherlands) are modeled with all model attributes including intertemporal constraints. In order to reduce computation complexity, interconnector restrictions between Poland and Czech Republic (PLCZ) as well as between Austria and Switzerland (Alps) are neglected. Therefore, these country pairs form one power market each. The same applies for the Nordpool area (North), consisting of Finland, Norway and Sweden, the Iberian peninsula as well as UK and Ireland (UKIE). The latter pooled countries as well as Italy and Belgium are treated differently in the model. Since they are important for the interregional exchange decision of the neighboring countries of Germany, they are also modeled in full temporal resolution, but with a limited equation set (e.g. ramping constraints are removed). In this way, the exchange decisions of the surrounding markets of Germany are taken into account, but instead of the full complexity, a pure merit-order perspective is implemented in these remote zones. As already mentioned above, the individual power markets are able to exchange energy to reduce costs. Although the western European power markets are closely connected, the exchange is limited by net transfer capacities (NTC). The initial NTC values are based on ENTSO-E (2010) and the development is derived from (EWI (2010)).

Demand Side Assumptions

The net electricity consumption excluding plant consumption and consumption of pumped storage plants is derived from the 'National Renewable Energy Action Plans' (NREAP), which each country submitted to the EU Commission (2010). These plans show the expected development until 2020. Since energy efficiency is one of the main goals of the European energy strategy, it is assumed that the electricity demand remains on the 2020 level until 2030 (see Table 1).

One important information of the NREAP is a detailed plan how each country intends to reach its renewable energy targets, whereas the 'EU Renewable Directive' (European Union (2009)) only states overall targets for the renewable energy share of the total energy consumption. The NREAP show the targets by sector and even by energy source. After 2020, the German technology specific RES-E targets are derived from the 'Leitszenario 2010' of the German Federal Ministry of Environmental Affairs (BMU (2010b)). The corresponding technology specific RES-E targets are shown in Figure 3. The RES-E development for the other countries for the time frame after 2020 is assumed to increase further, but by a reduced growth pace of 50% compared to the development from 2010 to 2020.

Table 1: Net electricity consumption excluding own consumption and consumption of pumped-storage plants [TWh_{el}], source: author

Zone	2010	2015	2020	2025	2030
Germany	557	547	525	525	525
France	494	503	513	513	513
Netherlands	116	123	130	130	130
Denmark	34	36	36	36	36
PLCZ	191	197	203	203	203
Alps	105	109	116	116	116
Italy	332	343	355	355	355
Iberia	319	357	403	403	403
Belgium	84	85	86	86	86
UKIE	373	382	391	391	391
North	373	382	391	391	391

The RES-E infeed structures are based on historic weather data. For wind power infeed, the same data source is used as for EWI (2010), where wind speeds from various weather station across Europe have been collected. Since the wind speeds are collected at relatively low measuring points, they are first adjusted by applying a power law adjustment to estimate wind speeds at hub heights. The wind speeds are then converted into electricity by applying a modified wind farm power curve as done in Holttinen (2005) to estimate the power production across larger geographical areas (for comparisons of actual versus modeled power generation from wind speeds, see Fripp and Wiser (2008)). For the PV infeed structure, NRELs 'Solar Advisor Model' (NREL (2010)) has been utilized. It converges measured solar irradiation data into PV generation. The weather data are provided by the U.S. Department of Energy's 'Energy Efficiency & Renewable Energy Program' (DoE (2010)).

Supply Side Assumptions

The economics of individual conventional technologies are determined by various technological and economic properties. Investment costs assumptions and efficiency development follow IEA (2010). Table 2 provides an overview on properties of current technology design as well as on assumptions for future investment options from 2020 on.

The assumptions on storage technologies follow Dena (2010). Pumped hydro storage can only be commissioned exogenously and has a round trip efficiency of 76%. CAES[1] on the other hand can be commissioned endogenously with a six full load hours storage and a round trip efficiency of 70%. The required reserve for system services follows ENTSO-E (2009) and is assumed to be 8.2 GW for positive and negative reserve of which 50% are spinning and 50% non-spinning respectively. Even though this level is slightly higher than today's levels, it is still a moderate assumption since the power system requires a certain amount of conventional generation online to supply grid stabilizing services, such as inertia, frequency control and reactive power in addition to the pure reserve requirements. For the annualization, an interest rate of 10% is assumed for the conventional power plant investments. Furthermore, all costs in this analysis reflect 2009 values. The fuel and CO_2 prices can bee seen in Table 3. In 2010 they are primarily based on the 2009 values of IEA (2010) as well as the coal price assumptions in subsequent years. Natural gas price assumptions after 2010 follow BMWi (2010a). CO_2 price assumptions are based on the impact assessment of the European RES-E directive (Capros et al. (2008)).

[1] CAES in this case is an advanced adiabatic compressed air energy storage, which does not require the co-firing gas and has a higher efficiency than diabatic compressed air energy storage. See e.g. Gatzen (2008) for an analysis of various storage technologies.

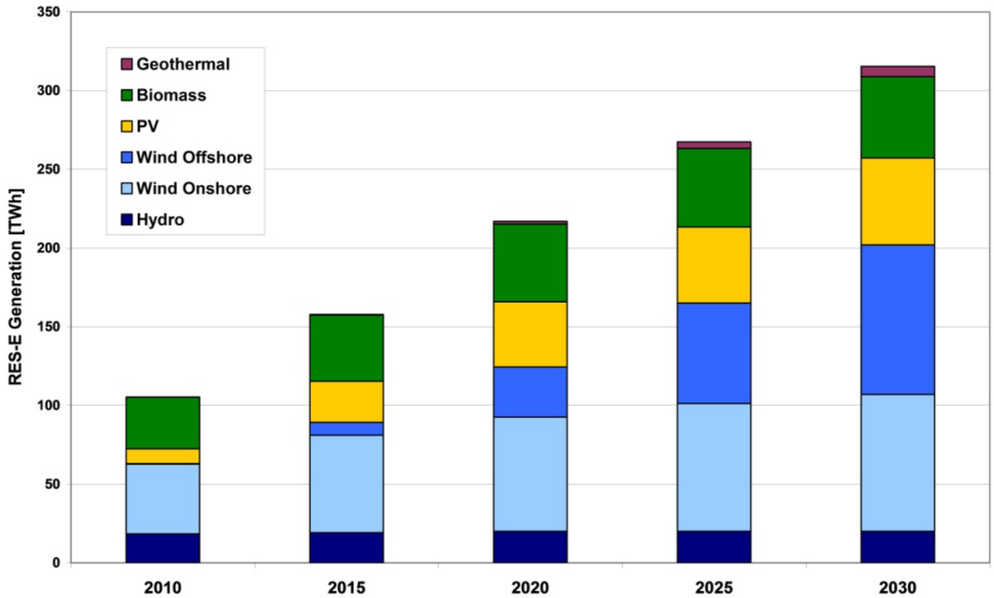

Figure 3: German RES-E generation targets, source: author, based on EU Commission (2010) and BMU (2010b)

Table 2: Conventional technology input assumptions, source: author assumptions, based on information from IEA (2010)

Technology	Parameter	Unit	2015	from 2020 on
Nuclear	Investment Cost	$\frac{EUR}{kW}$	2,735	2,735
	Efficiency	%	33	33
Lignite	Investment Cost	$\frac{EUR}{kW}$	1,368	1,576
	Efficiency	%	43	48
Coal	Investment Cost	$\frac{EUR}{kW}$	1,368	1,576
	Efficiency	%	46	50
CCGT	Investment Cost	$\frac{EUR}{kW}$	648	648
	Efficiency	%	57.8	61
OCGT	Investment Cost	$\frac{EUR}{kW}$	389	389
	Efficiency	%	35	40
Superpeaker	Investment Cost	$\frac{EUR}{kW}$	370	370
	Efficiency	%	35.4	35.4

Table 3: Fuel price assumptions, source: author assumptions, based on BMWi (2010a), IEA (2010) and Capros et al. (2008)

Fuel	Unit	2010	2015	2020	2025	2030
Nuclear	$\frac{EUR}{MWh_{th}}$	3.6	3.6	3.6	3.6	3.6
Lignite	$\frac{EUR}{MWh_{th}}$	1.5	1.5	1.5	1.5	1.5
Coal	$\frac{EUR}{MWh_{th}}$	8.6	8.6	9.4	9.7	9.9
Natural Gas	$\frac{EUR}{MWh_{th}}$	18.2	25	23	24.5	26
CO_2	$\frac{EUR}{tCO_2}$	15	33.8	42.7	45.6	48.5

4.2 Scenario Definitions

The scenario selection is based on different existing RES-E policies and their induced curtailment policy. In case an oversupply situation requires curtailment, a novel modeling approach is applied. Most RES-E integration studies (e.g. BMWi (2010b)) allow curtailment at a price of zero. However, the analysis in Figure 1 for Texas shows that the price level at which RES-E is curtailed depends on the support scheme. In the case of Germany without a curtailment rule, the power price dropped even to -500 EUR/MWh in 2009 without any curtailment rule in place. In theory, it could even have dropped to -3000 EUR/MWh. In the case of Texas on the other hand, market-driven curtailment is observable at negative power prices which reflect the PTC price for RES-E support. In the present analysis, a premium system for Germany is assumed for the 'Base' scenario. Since the currently implemented rule would result in an extreme scenario, it is modeled separately as a sensitivity case. It is likely that Germany implements a premium system in the next EEG amendment in 2012. The assumed premiums do not reflect the required support level, but serve as proxy for the market-driven curtailment. These premiums are derived from the difference between levelized generation costs of the technologies and an average power price level. Wind onshore receives a premium of 34 EUR/MWh, wind offshore 96 EUR/MWh, solid biomass 46 EUR/MWh, gaseous biomass 116 EUR/MWh, liquid biomass 118 EUR/MWh, geothermal 96 EUR/MWh and PV 414 EUR/MWh.[2] These premiums in the Base scenario remain constant throughout the modeling period to ease the interpretation over time. The regulations in the sensitivity scenarios are explained below in the scenario definitions.

- **Base Scenario:** The 'Base' scenario serves as main reference point. The results of the other scenarios are always compared to the results of the 'Base' scenario. This scenario is characterized by a premium system assumption, which allows marked-driven curtailment as explained above. The conventional part of the market is characterized by the nuclear phase-out according to a political agreement in 2002.[3]
- **Curtail0:** The 'Curtail0' scenario does not allow negative bids for RES-E and therefore curtails the infeed as soon as the price is below zero as assumed in most RES-E integration studies.
- **Curtail150:**The 'Curtail150' scenario, starts curtailing at -150 EUR/MWh. It is motivated by the current rule of the German regulator BNetzA, which states that when the spot price reaches -150 EUR/MWh, a second auction is allowed with limited RES-E bids from the TSOs.
- **Curtail3000:** The 'Curtail3000' scenario simulates a pure feed-in tariff system with a TSO infeed obligation as it is defined in most FIT systems. The curtailment level of -3000 EUR is defined by the floor of the Epex Spot. This design provides a strong investment security for RES-E, but has obvious weaknesses in the system integration at high penetration levels. This is also the reason why this current FIT design in Germany does not qualify as base scenario.

4.3 Modeling Results

This section provides an overview of the scenario results on an aggregated level. The results of particular system components are compared between all scenarios. First, the total costs of all scenarios for Germany represent primarily the supply side and are compared with the 'Base' scenario in Figure 4. The calculations include investment costs, operation and maintenance (O&M) costs, variable generation costs, import costs, partload costs and start-up costs. If RES-E can be curtailed as soon as their market value is 0 EUR/MWh, as assumed in the 'Curtail0' scenario, system costs are also slightly lower than with the assumed premium system in the 'Base' scenario. This is due to the perspective

[2] The levelized generation costs are based on investment costs from IEA (2010) and do not fully reflect recent price reductions in some technologies.

[3] In fall 2010, when the scenario assumptions were set, the political discussion on nuclear lifetime extensions was still ongoing. Therefore, the nuclear phase-out still serves as business-as-usual assumption.

of economic dispatch at marginal costs of intermitting RES-E. Interfering with the dispatch based on marginal costs due to political regulation increases by definition the system costs. This is best reflected by the 'Curtail3000' scenario where the market is much more firm due to the extremely high curtailment costs. This additional firmness is reflected by the higher system costs compared to the 'Base' scenario. One can see that the scenario differences increase over time as the system adapts in

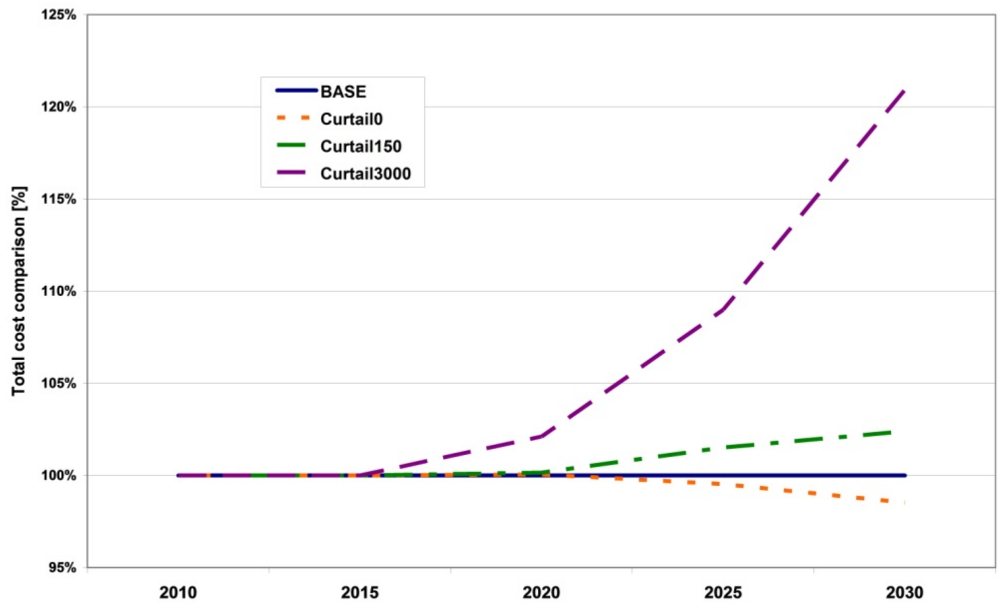

Figure 4: Total cost comparison for Germany, source: author

the individual scenarios. For instance the 'Curtail3000' scenario is much more expensive with a higher RES-E share in later years. Changing the RES-E integration rule, from market bids based on variable cost of zero to an infeed obligation with a forced market clearing at -3000 EUR, increases the costs by more than 20% in 2030. The following subsections discuss the effects on the individual market components to identify the changes in these segments.

The Supply Side

THEA optimizes the capacity mix and the dispatch according to the scenario attributes. Therefore, Figure 5 shows the capacity mix development for each scenario for the years 2020 and 2030 in addition to the starting point in 2010. Overall, it is observable that the total capacity portfolio increases over time and that the demand for conventional technologies is only slightly reduced due to capacity adequacy reasons. However, since the superpeaker technology serves as option to fulfill the capacity requirements but is hardly utilized, differences in the quality of the capacity mix can be observed. This is actually the main advantage of the usage of the superpeaker technology. Without this option, the amount of OCGTs would have been used to provide sufficient capacity as e.g. observed by Decarolis and Keith (2006). With the usage of the superpeaker technology, the quality of the required peak capacity can additionally be assessed. As soon as the utilization of the superpeaker technology reaches a certain share, OCGTs are the economic choice due to a more favorable ratio of investment and variable costs. In other words, if the utilization of a peaker technology is required and therefore it does not primarily serve the capacity requirement, OCGTs are installed. Therefore, OCGTs are required to a certain degree to cover the hours of peak demand. Additionally, OCGTs are able to provide tertiary reserve since they are quick-starting units. The superpeaker technology does

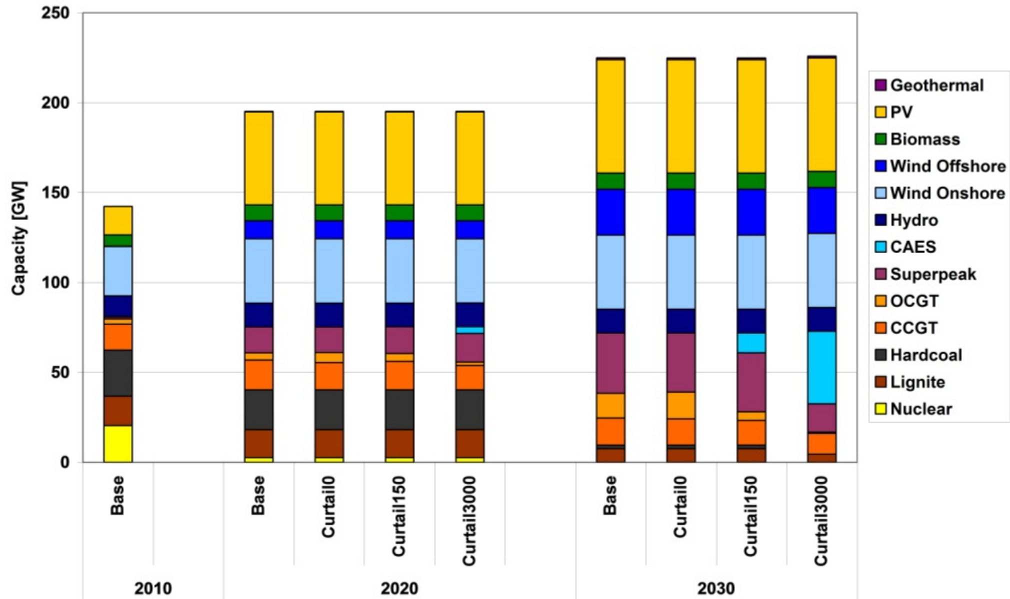

Figure 5: Capacity mix comparison, source: author

not provide this quality. In the assumed premium system of the 'Base' scenario as well as in the free curtailment scenario 'Curtail0', investments in OCGTs are required to provide flexibility in the energy and the reserve market. If higher curtailment costs are assumed, as in the out-of-market assumption in the 'Curtail150' case, where an artificial threshold is defined by the regulator at which curtailment is required to avoid too extreme negative prices, the commissioning of 11 GW CAES crowd out parts of the OCGT fleet and provide the required flexibility instead. If no curtailment rule is applied and the market reaches its limit at -3000 EUR as in the 'Curtail3000' scenario, the effects are much more extreme. However, market rules would quickly change if oversupply situations resulted in prices of -3000 EUR without market clearance. Therefore, this scenario should not be interpreted as realistic. It simply shows that forced RES-E infeed has its limits. In order to avoid the extremely high curtailment costs, investments in 40 GW CAES are observable, which store the RES-E oversupply and avoid too high curtailment costs. The immense CAES fleet provides the entire flexibility requirement and replaces almost the entire OCGT fleet and significantly reduces the required superpeaker capacity. Since the storage technologies benefit from storing energy at extremely negative prices and releasing it to the market at positive prices, their profits increase as shown in Figure 8. Storage technologies benefit from market firmness, since they are able to provide flexibility on both side of the market, the peak hours and the oversupply hours. Additional lignite and hardcoal decommissioning can also be seen in the 'Curtail3000' scenario in 2030. The forced RES-E infeed strongly penalizes baseload capacity and requires the installation of flexible CAES capacity. The high amount of superpeaker capacity is a sign that a higher share of the energy demand can be met by cheaper imports from at least one of the surrounding markets most of the time as can be seen in Figure 6. Overall, the generation capacity becomes more peak oriented with higher curtailment costs. As a consequence of the diverging capacity developments, the generation mix varies significantly as well between most of the scenarios. Even more firm market situations are present in the 'Curtail3000' scenario. The significant amounts of CAES storage and generation are a clear sign of flexibility demand if RES-E is forced into the market. Overall, Germany becomes a netimporting country throughout the scenarios, which confirms the findings of other recent studies such as BMWi (2010a), BMWi (2010b) and BMWi (2010c). Figure 7 shows in more detail the development of the international exchange over time. The

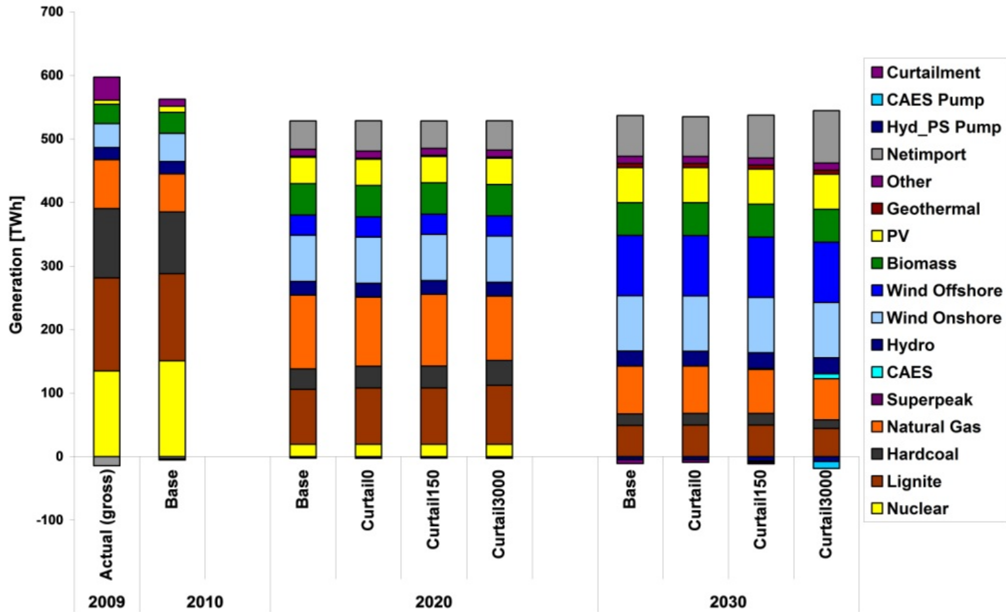

Figure 6: Generation mix comparison, source: author and AGEB (2010)

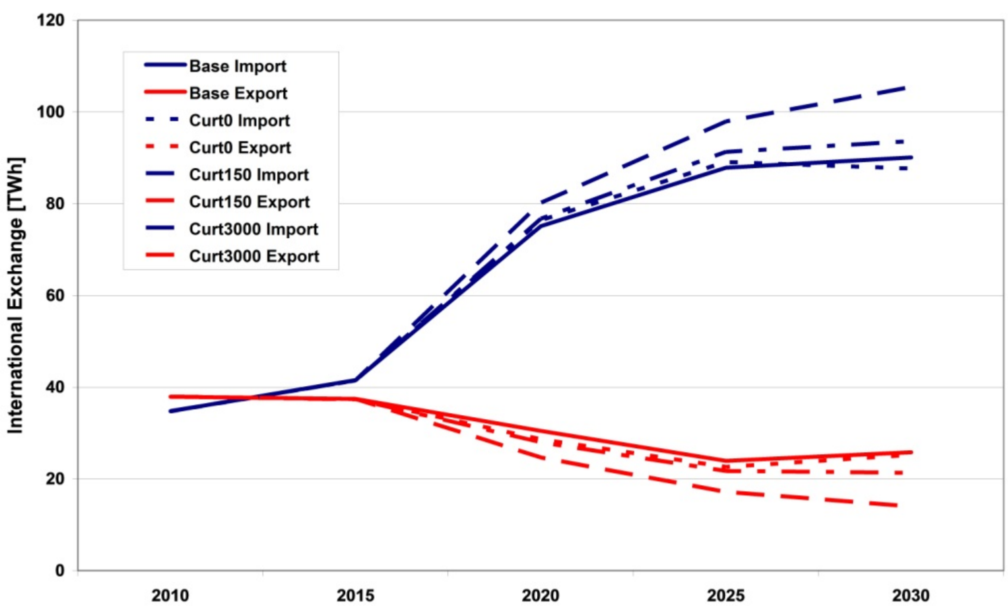

Figure 7: Development of international exchange, source: author

overall trend shows that exports decrease over time while the imports increase. This phenomenon is attributed to the phase out of the German baseload capacity. Between the scenarios it is observable that the amount of exports decreases with higher curtailment penalties and the amount of imports increases. As explained above, the capacity mix is more peakload oriented with higher curtailment penalties. This leads to less cheap energy for export and more situations in which cheaper energy can be imported. A second reason for the reduced export is that energy in oversupply situation can be stored in the additional CAES plants. The shift in the generation structure has also consequences for the profitability of the particular technologies. Therefore, the pure cost perspective is extended by an analysis of the producer rent. Dependent on their economic and technical attributes, technologies have different values in the scenarios. Storage technologies have a better economic situation if the overall system is less flexible. In this case the provided flexibility of the storage technologies is very valuable for the system. Figure 8 shows the producer rents (PR) per technology in all scenarios. The

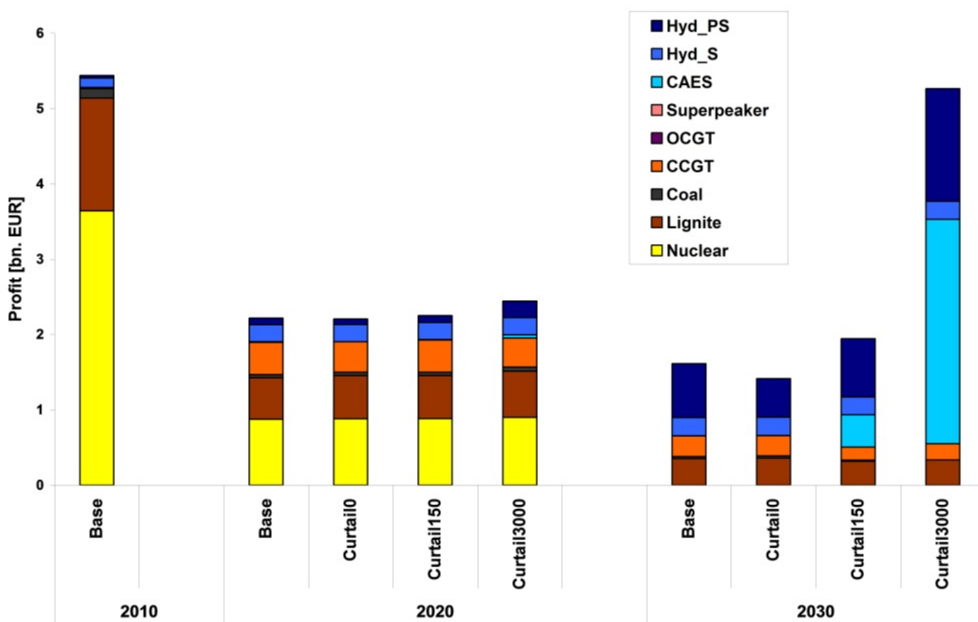

Figure 8: Producer rent comparison, source: author

calculation mirrors the short-term perspective, meaning that the energy and reserve market income per technology is reduced by the variable costs. Consequently, this analysis represents the profitability of existing units and fixed costs are treated as sunk. Since each technology receives the power price for their produced energy, which is set by the marginal unit, the PR are highest for base load technologies.

The system is under pressure in the 'Curtail3000' scenario, where the flexibility of curtailment is penalized with 3000 EUR. Consequently, the profitability of pumped hydro storage increases. In the 'Curtail150' and the 'Curtail3000' scenario, additional flexibility is required for economic operation, which leads to investments in CAES capacities. The demand and therefore the profitability for CAES is even higher in the expensive curtailment scenarios. Here, CAES profits from compressing energy at negative prices and generating at positive prices. This is a clear sign that flexibility becomes highly valuable if other system components are less flexible and therefore benefits from the higher price volatility. In order to provide an overview of the future price volatility Figure 9 shows the price duration curves of the 'Base' scenario for the years 2010, 2020 and 2030. The development towards higher RES-E shares leads to a steeper slope of the price duration curve. The large plateau in the negative price area in 2030 represents the curtailment of wind power at the negative value of the

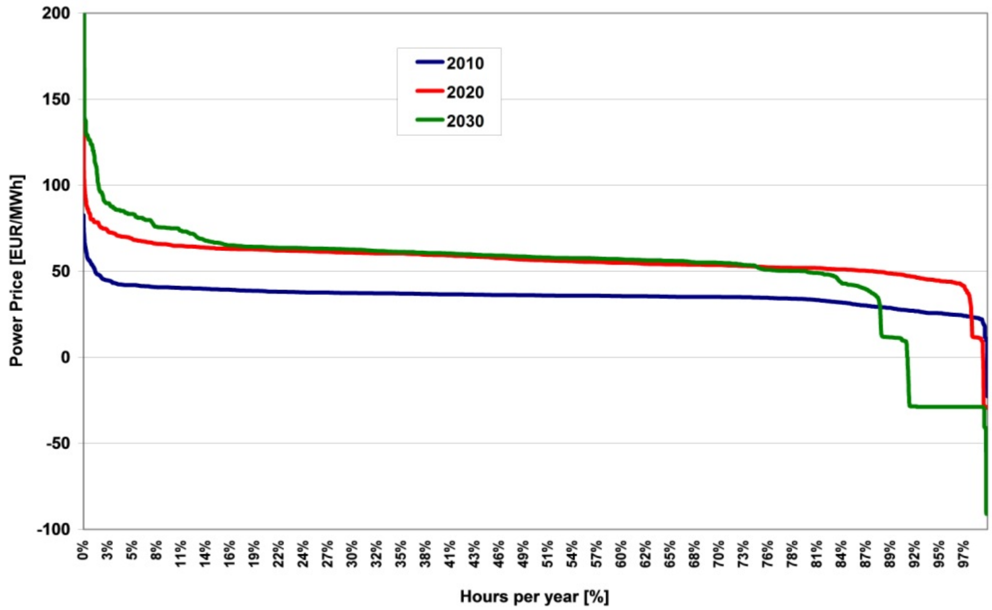

Figure 9: Price duration curves of the 'Base' scenario, source: author

premium as explained with the ERCOT example in the motivation. The development towards higher price volatility has strong effects on all system components which will be discussed in more detail in the following.

Figure 10 shows the reserve market volume as indicator of market firmness. Compared to the 'Base' scenario, the 'Curtail0' scenario shows less firmness due to the ability to curtail the RES-E oversupply without any costs. This possibility is treated as additional flexibility in the market. This flexibility is reduced as soon as the curtailment penalty increases. As discussed above, the market firmness increases in the 'Curtail150' scenario to a level that requires CAES to reduce the firmness. The reserve market volume increases nevertheless to 112% of the 'Base' scenario in 2030. The forced RES-E infeed in the 'Curtail3000' scenario increases the firmness further, which has been seen in the high CAES investments and can also be seen in the reserve market volume, which rises to 217% of the volume of the 'Base' scenario.

The Demand Side

While certain technologies are more profitable depending on the scenario setting, the consumer has to pay the corresponding market price. Therefore, the term consumer cost is based on the resulting market prices. Figure 11 shows the consumer costs, divided into market relevant costs (energy and reserve market) and RES-E support costs. This analysis takes into account the energy market price, the reserve market price as well as the RES-E support value. Other consumer cost components, such as other grid fees and taxes are not included in the analysis. The energy market costs for the consumer is the demand in each hour valued by the power price. The total energy market costs increase due to the rising fuel costs. The reserve market costs are part of the grid fees in Germany and consist of the price of the reserve products multiplied by the reserve requirements. The RES-E support costs are calculated as the difference between the levelized generation costs of each technology, which mirrors the required support payment, and the market price in each hour. To calculate the levelized generation costs, which are used to estimate the required support costs for the scenario comparison, future in-

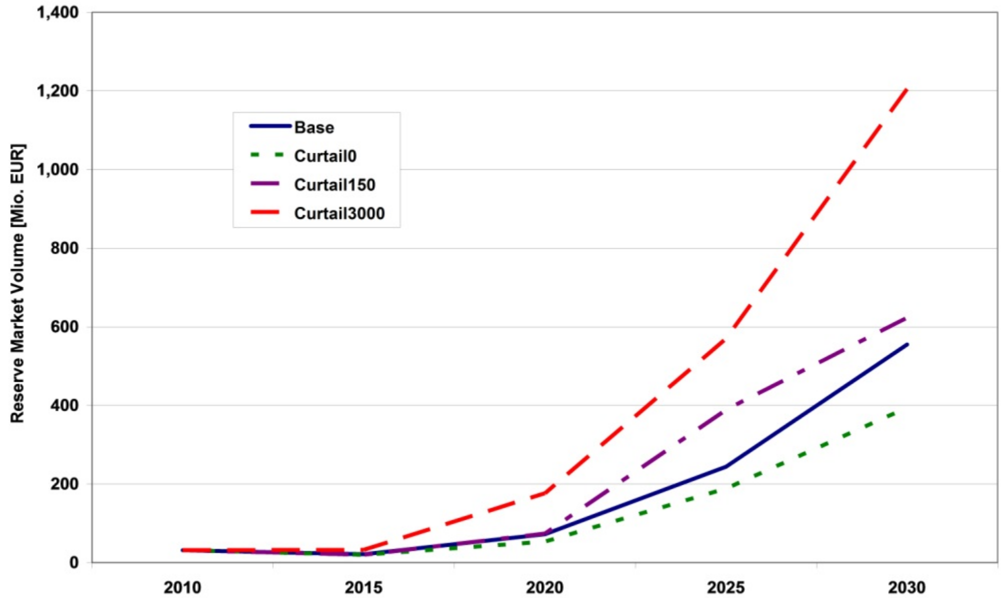

Figure 10: Reserve market volume ('Base' vs. 'Curtail0', 'Curtail150' and 'Curtail3000'), source: author

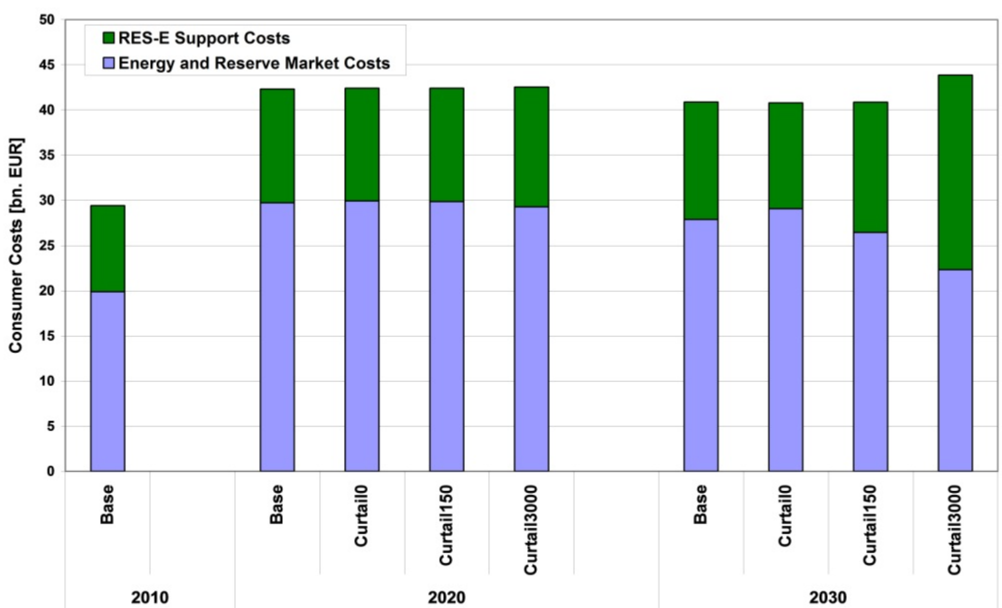

Figure 11: Consumer cost comparison, source: author

vestment cost assessments are taken from IEA (2010) and variable biomass costs from BMU (2010b).[4] To annualize the investment costs, a depreciation time of 20 years and an interest rate of 8% is assumed.

It is assumed that in this support scheme design, the regulator knows how much curtailment occurs each year and the levelized generation costs take the actual full load hours into account. This means, that the support payment is higher if a technology is curtailed more often in order to enable the recovery of the fixed costs. This approach avoids that the support scheme costs are lower if more curtailment occurs. The total support scheme costs therefore depend directly on the value of the individual RES-E in each hour.[5] In reality, the FIT is locked in at the year of commissioning and is valid for 20 years. In the present approach, the level is calculated for each year individually in order to ease the interpretation without carrying costs resulting from previous years, which cannot directly be attributed to particular effects. The support costs which the consumer has to pay are the aggregated differences between the FIT (here levelized generation costs) and the market value of RES-E.

The overall consumer cost burden remains relatively stable between the different curtailment cases with the exception of the 'Curtail3000' scenario. It can be seen that the RES-E integration policy strongly affects the cost distribution. RES-E support costs are the lowest in the 'Curtail0' scenario, followed by the premium system assumption in the 'Base' scenario. The out-of-market curtailment level of at least -150 EUR in the 'Curtail150' scenario strongly increases the support costs, but at the same time reduces the energy market costs almost to the same extent. In sum it is slightly more expensive than the 'Base' scenario. The 'pure' FIT system assumption with the infeed obligation in the 'Curtail3000' scenario not only increases the RES-E support costs, but also increases the total consumer costs. It becomes apparent that the forced RES-E integration strongly affects the entire system, which consequently leads to a higher cost burden for the consumer. As explained above, the effects are compared to each other on the basis of the required support costs based on levelized generation costs for each year. In order to provide a better understanding of the effects, Figure 12 shows the support cost differences between the scenarios per MWh for a wind power plant, which is installed in 2010 and receives the same absolute FIT until 2030. The levelized generation cost, which represent the required FIT level, is 83.9 EUR/MWh based on the previously discussed assumptions. The difference between the FIT and the market value of the wind energy is the required support costs, which is passed on to the consumers (as seen in Figure 11). Due to the increase of the fuel costs after 2010, the required support costs are reduced in all scenarios. At a certain penetration level, the value of wind power is reduced due to its price depressing effect. This leads to an increase of the required support costs. The particular value of wind energy depends on the scenario assumptions. Overall, the support cost depend on the flexibility of the entire system and its ability to absorb the wind energy. The 'Curtail3000' and 'Curtail150' scenarios reduce the flexibility of the market compared to the 'Base' scenario and therefore require higher support costs.

It is intuitive that the support scheme design affects the consumer costs, which can be seen in Figure 11. While the RES-E support costs increase with the curtailment penalty, the overall costs remain more or less the same with exception of the extreme penalty assumption in the 'Curtail3000' scenario in which the overall costs for the consumer increase. Because the more RES-E is forced into the market, the lower the energy market costs. Therefore, the value of RES-E and consequently the total RES-E support costs strongly depend on the support scheme design. Figure 13 shows the scenario comparison of the relative RES-E value. The increase of the curtailment penalties reduces the value of the individual RES-E. In the 'Curtail0' scenario, the individual RES-E value is the highest,

[4]The costs do not entirely reflect the current cost structure. Especially the assumed PV investment costs do not reflect the rapid cost decrease in the recent years. Nevertheless, since the analysis focuses on the differences between the scenario comparison and not the absolute values, the deviations from current cost levels can be ignored.

[5]The previously defined curtailment penalties would in reality mirror the height of the particular premium. In this modeling framework, this would require additional iterations to specify the height of the premium, since the amount of curtailment has repercussions on the required support level. Therefore, the applied curtailment penalty and the support costs can deviate in this approach.

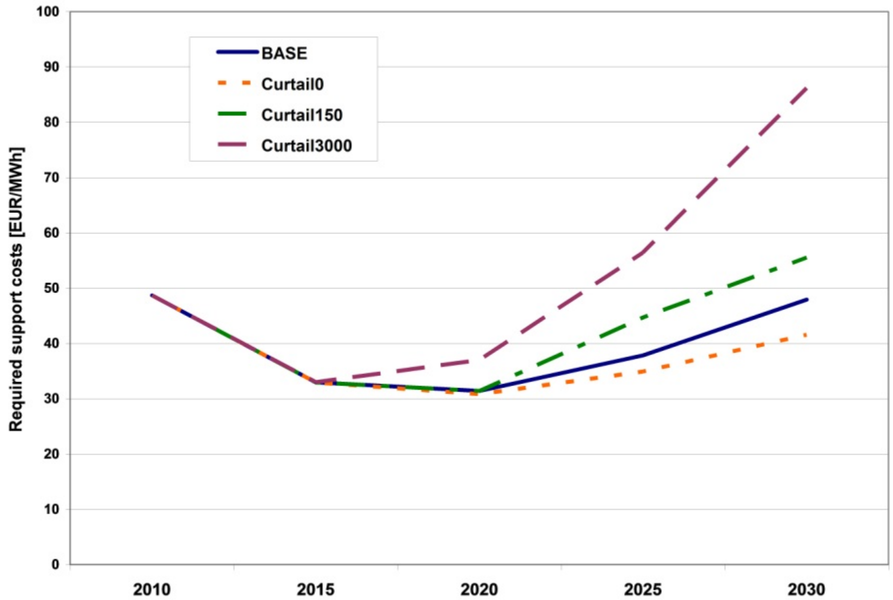

Figure 12: Support cost difference per MWh for a wind power plant installed in 2010, source: author

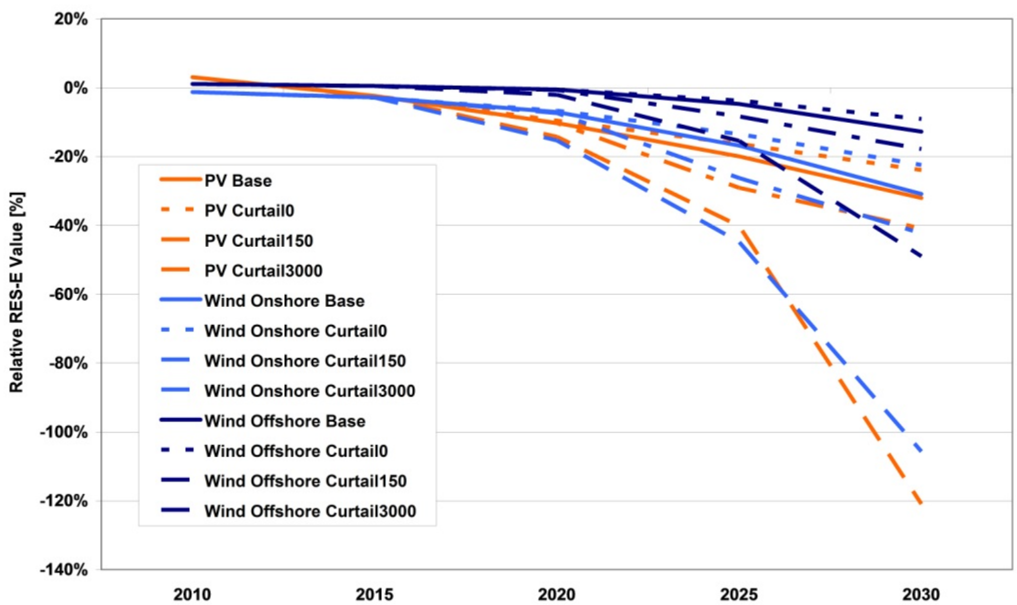

Figure 13: Relative RES-E value ('Base' vs. 'Curtail0', 'Curtail150' and 'Curtail3000'), source: author

since curtailment triggered as soon as the power price is zero and the value reducing effect is primarily the merit-order effect. The results of the premium assumptions in the 'Base' scenario are primarily curtailment decisions at slightly negative prices above -100 EUR/MWh. The RES-E value is therefore slightly lower than the one from the 'Curtail0' scenario. The out-of-market curtailment level of -150 EUR/MWh in the 'Curtail150' scenario shows already stronger value reducing effects. These effects are the highest in the 'Curtail3000' scenario. Even though the majority of curtailment is avoided by the CAES storage, the RES-E values decrease dramatically. Figure 14 shows the absolute values, which directly determine the total RES-E support costs for the consumers. The high curtailment penalty

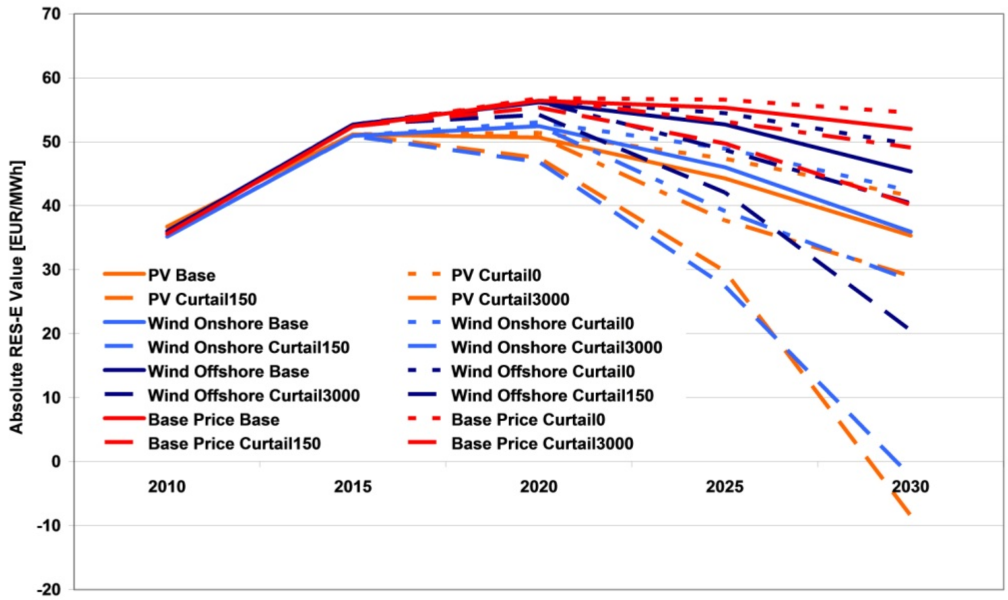

Figure 14: Absolute RES-E value comparison ('Base' vs. 'Curtail0', 'Curtail150' and 'Curtail3000')

in the 'Curtail3000' scenario leads to negative RES-E values for PV and wind onshore. Even though the total RES-E curtailment is reduced to 2.6% of the amount of the 'Base' scenario in 2030, the impact on the value is high enough to result in a RES-E value below zero. While in the 'Curtail150' scenario the total curtailment amount is reduced to 40% of the 'Base' scenario in 2030, the value of PV is reduced to 82% of the value of the 'Base' scenario and the value of wind onshore to 79%. The same logic applies in the 'Curtail0' scenario, where the RES-E values are above the ones from the 'Base' scenario. Also the base prices reflect the impact of the curtailment penalties. While the price in the 'Curtail0' scenario is 5% above the one from the 'Base' scenario, the prices for the 'Curtail150' and 'Curtail3000' scenarios are 6% and 23% lower respectively. The scenario comparison of the price behavior in 2030 can be seen in Figure 15 by the price duration curves. The overview of the price duration curves illustrates the impact of the RES-E support scheme designs and their corresponding curtailment rules. While the 'Base' and the 'Curtail0' scenarios show similar price patterns, apart from the lowest price levels which are set by the different curtailment penalties, the patterns in the other two scenarios deviate stronger. The 'Base' scenario curtails at the individual RES-E premium levels and shows overall negative prices in 8.8% of the time. The 'Curtail0' scenario curtails at a power price of zero, which is the market results in 9.1% of the time. Both scenarios show the same pattern at the positive side. The 'Curtail150' scenario starts curtailing at -150 EUR/MWh. However, the price also drops to lower values compared later to the 'Base' scenario. The reason for the delayed drop in the 'Curtail150' scenario is the added storage capacity, which reduces the market firmness in these hours. Due to the utilization of the additional CAES storage in the 'Curtail150' scenario, negative

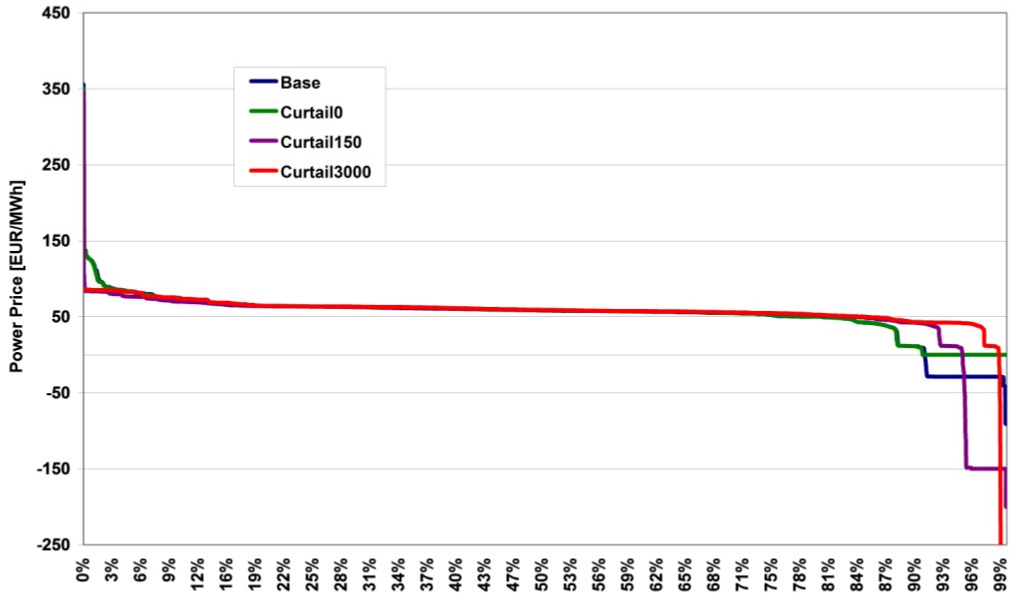

Figure 15: Comparison of price duration curves ('Base' vs. 'Curtail0', 'Curtail150' and 'Curtail3000'), source: author

price results can be reduced to 4.8% of the time. This effect is strongly increased in the 'Curtail3000' scenario, since the high curtailment penalty leads to much higher CAES investments which delay the price drop and lead to negative prices in less than 0.8% of the time. On the positive price side, the two lower curtailment cost scenarios deviate in a few hours to higher prices due tot he utilization of OCGTs. This pattern is avoided in the other two scenarios due to the utilization of the additionally stored energy.

In sum, the RES-E support scheme design strongly influences market behavior as soon as critical penetration levels are reached which lead to firm market situations. The generation capacity becomes more peak oriented with higher curtailment penalties, which requires higher netimport amounts. At a certain point, even CAES investments are required to provide flexibility to enable efficient market clearance. The consumer has to bear higher RES-E support costs when RES-E are forced into the market, but benefits from reduced energy market costs until the distortions of the market become too extreme and costly flexibility options are required. On the one hand, the market benefits from price signals, which reflect the requirement for flexibility. On the other hand, too much market distortions through too ambitious RES-E integration forces result in higher costs and penalize the RES-E value substantially.

4.4 Critical Discussion of Modeling Results

The modeled scenarios provide an overview on adaptation effects under different policy scenarios in high temporal resolution. With an increasing RES-E penetration, it has been shown that the more friction is in the market, the higher is the peak oriented generation capacity. This finding confirms the results of previous studies such as Dena (2005), Lamont (2008) and EWI (2010) who show that less baseload capacity is required in high RES-E power systems. However, since a deterministic approach is applied, the results can still be considered as conservative. By trend a stochastic approach which incorporates uncertainty e.g. in terms of forecast errors, would lead to an even higher peakload share. The present analysis extends the previous research by applying various curtailment rules. The effects are noteworthy. Depending on the level of the curtailment penalty, the power market adapts to the degree of flexibility the curtailment rule implies. Under high curtailment penalties, substantial investments in CAES can be observed. Decarolis and Keith (2006) showed that diabatic CAES is not competitive in a carbon constrained system with a wind energy share of 70% of the load. Without knowing how curtailment is treated in their analysis, this finding cannot be confirmed for advanced adiabatic CAES. Gatzen (2008) concludes that adiabatic CAES could be a successful storage application. Nevertheless, he underestimates the increasing price volatility due to intermitting RES-E and neglects curtailment penalties. Therefore, he assumes a future flattening of the merit-order which cannot be confirmed by the present research.

Therefore, this approach extends findings of other studies, such as BMWi (2010a) and BMWi (2010b), who also calculate high RES-E penetrations in the German power market, but apply curtailment at power prices of 0 EUR/MWh as applied in the 'Curtail0' scenario. These previous findings substantially underestimate the integration challenges due to the assumed flexibility of RES-E curtailment. As long as the the power price drops to at most 0 EUR/MWh, this price depressing effect seems beneficial. If the price drops to -150 EUR/MWh frequently (as currently defined by the BNetzA), integration challenges are recognized and seem much more alarming than a frequent price of 0 EUR/MWh.

Besides the findings for CAES, the curtailment rule shows also significant insight into RES-E support costs. In fact, a trade-off is observable between high curtailment penalties, which lead to system adaptations and lower RES-E support costs, which are present with relaxed curtailment penalties. The fundamental challenge is already observable in todays firm market situations as discussed in Nicolosi (2010). The firmness of the power market would even be increased if additional must-run generation restrictions which are required for system services in addition to reserve requirements would be applied.

5 Conclusion

The integration of large amounts of RES-E challenges the operation of the power system and leads to long-run adaptations. The market firmness is observable in negative power prices and high prices for negative reserve products. These market results signal additional demand for flexibility in the market and therefore already indicate requirements for system adaptation.

The negative correlation of RES-E infeed and power prices has already been discussed in the literature but still calls for additional modeling applications in real-scale power systems with international exchange. Open research questions are further found to concern long-run system adaptations, especially in set-ups which reflect the complexity of intermitting RES-E infeed and operational power market requirements. The present article adds particular curtailment policies of RES-E support schemes to capacity expansion power system modeling in a real-scale power system with 8760 hours in a multi-year, multi-zonal set-up.

Compared to the latest literature, the applied approach captures a significant part of the complexity which RES-E infeed places on the power system. Nevertheless, further research is required to fill open spaces, which were not addressed in detail in the present analysis. The research has been conducted from the perspective of a well informed benevolent planner to capture the fundamental system adaptations. Nevertheless, the real world is usually characterized by more friction than a purely linear optimal world. Therefore, a magnitude of different approaches can be applied to the analysis of RES-E integration challenges. Besides game theoretic assumptions on the behavior of more or less dominant market participants, more detail can also be applied in the operation of the system. While the present research captures fleet-wide operational constraints, specific power blocks can be modeled for a more detailed analysis. While block specific dispatch models are used for short time periods (e.g. the day-ahead market), long-run system adaptations are not yet analyzed with such detail. From an IT technical point of view this is currently quite challenging, future IT solutions however might enable this degree of detail.

The findings of the present research are summarized in the following. The value of RES-E has been shown to be strongly affected by the particular scenario setting. Overall, the consumer costs induced by the power market are reduced due to a higher RES-E share if RES-E is forced into the market. On the other hand this increases the RES-E support costs, but triggers capacity adaptations which are required in the long run. Figure 16 shows the dimensions which should be considered by policy makers for the long-term development of the power system. One finding, which has not yet been discussed

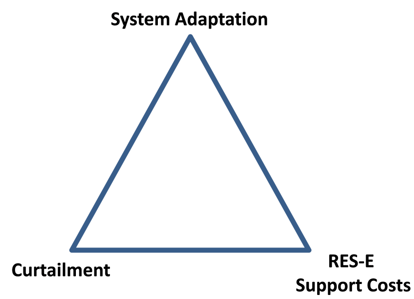

Figure 16: Renewable integration triangle, source: author

in the literature is the importance of the RES-E support scheme, and in particular its corresponding RES-E integration policy, for the long-run system adaptation. The RES-E integration policy is one major flexibility design criterion in power systems with a high RES-E penetration. It has been found that if RES-E is forced into the market by heavily penalizing curtailment substantial flexibility requirements are forced upon the remaining system, which even results in substantial investments in storage technologies. This finding is not only important from a market design perspective, but also for modeling RES-E integration in general.

Furthermore, the value of the grid infrastructure increases due to the higher value of diverging system imbalances. If RES-E can be curtailed without much additional costs, e.g. based on a premium payment, the integration challenges are relaxed since RES-E provides additional flexibility to the system. This on the other hand leads to lower market signals which could trigger system adaptation.

In conclusion, it is shown by this research that the design of all system components which affect the flexibility of the market requires careful consideration in order to enable a system adaptation which allows for higher RES-E shares.

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