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# An optimal mix of conventional power systems in the presence of renewable energy: A new design for the German electricity market

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ABSTRACT

In this paper we develop a new market design for the German electricity market. Our new market design simultaneously ensures security of energy supply and ongoing expansion of renewable energy (RE). The methodological approach applied considers the special challenges resulting from the intermittent nature of RE – we simulate developments in the German electricity market between 2015 and 2034 and differentiate across various power plant technologies according to their ability to flexibly react to changes in the residual load. In theory, a composition of power plants that is optimally adapted to residual load always leads to the most cost efficient supply of electricity. However, our empirical analysis demonstrates that this does not necessarily lead to an improved market environment, both in terms of power plant profitability as well as uninterrupted power supply.

## 1. Introduction

Compared to the rest of the world, German consumers largely enjoy a secure electricity supply (defined as a permanent and sustainable coverage of demand for electricity). The average 'unavailability' of electricity per customer in 2012 was 15.91 min (Federal Network Agency, 2013). Uninterrupted delivery needs to be ensured both during peak load hours, as well as in the event of technical problems that lead to unexpected downtimes of (conventional and renewable) power plants (BMWi, 2012). In this context, an undergoing transformation of German energy policy poses major challenges to uninterrupted electricity supply in the near future. On the one hand, the gradual phasing-out of nuclear power, as decided by the German government in early 2011 after the events in Fukushima, is expected to lead to a considerable reduction of conventional generating capacity (Bundesgesetzblatt, 2011). Moreover, as a result of increased air quality standards, some older coal-fired plants will also shut down (European Union, 2010; BDEW, 2012). On the other hand, the increasing infeed of renewable energy (RE) also represents a further threat to the security of electricity supply. In order to counteract the expected strong fluctuations caused by RE reliance, it will be necessary to have a significant amount of controllable power plant capacity. Due to its close to zero marginal costs and the priority purchase obligation for its use, the increasing amount of RE does, however, lead to a reduction in the market price of electricity and the displacement of conventional power plants (Lang, 2007; Wüstenhagen and Bilharz, 2006; Federal Ministry of Justice, 2014). Hence, the profitability of conventional power plants may deteriorate to such an extent that many power plant operators are forced to consider closing down their plants (Sensfuß et al., 2008; Sorge, 2013).

Against this background, the ability to maintain a high level of supply security is already endangered in some regions in Germany (Amprion et al., 2013), with substantial energy deficits expected in the medium to long term (Matthes, 2012). As a temporary countermeasure, the German Federal Government has introduced a provision for procuring power reserves. Under this provision (and in return for an appropriate remuneration), those power plants considered to be indispensable for maintaining the security of supply are kept as a reserve

*Abbreviations:* BL, Base Load; BLPP, Base Load Power Plant; CCGT, Combined Cycle Gas Turbines;; CM, Contribution Margin; CPP, Full Power Plant Capacity; EEG, Erneuerbare Energien Gesetz (Renewable Energy Sources Act); FCPP, Annualised Fixed Costs of Power Plant; GT, Gas Turbines; GWh, Giga-Watt hours; I, Intersection; LDC, Load Duration Curve; LDCM, Load Duration Curve Model; MCB, Marginal Costs of Base load power plant; MCM, Marginal Costs of Medium load power plant; MCP, Marginal Costs of Peak load power plant; MCPP, Marginal Cost Curve of Power Plant; ML, Medium Load; MLPP, Medium Load Power Plant; MO, Merit Order; MW, Mega-Watt; MWh, Mega-Watt hours; NPV, Net Present Value; P, Price of electricity; Peak, Peak load pricing; PDC, Price Duration Curve; PL, Peak Load; PP, Power Plant; PLPP, Peak Load Power Plant; RE, Renewable Energy; RLDC, Residual Load Duration Curve; TCM, Total Contribution Margin of power plant; VoLL, Value of Lost Load

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outside the actual energy markets (Federal Ministry of Justice, 2013a, 2013b). Provisions for interruptible loads represent a further measure for ensuring a stable supply of electricity. Such provisions for interruptible loads would oblige energy-intensive companies to reduce their amounts of demand for a certain period in exchange for an agreed remuneration (Federal Ministry of Justice, 2013c). Such regulations are seen as temporary solutions with the intention to introduce a fundamentally new design for the electricity market in the near future. The goal of the new market model is to ensure a permanently secure supply without having to compromise on further expansion of RE.

To our knowledge, our analysis provides the first attempt to develop a new market design that simultaneously ensures security of energy supply as well as ongoing expansion of RE. In contrast to the existing literature (e.g. Nicolosi, 2012; Peek, 2012a, 2012b; Batlle and Rodilla, 2010; Boot and van Bree, 2010; Briggs and Kleit, 2013; Cramton et al., 2013; Gottstein and Schwartz, 2010; Keay-Bright, 2013; Meyer et al., 2014; Matthes et al., 2012; Neuhoff et al., 2013; Perkins, 2014), the methodological approach applied here explicitly considers the special challenges resulting from the intermittent nature of RE– we simulate developments in the German electricity market between 2015 and 2034 and differentiate across various power plant technologies according to their ability to flexibly react to changes in the residual load. Accordingly, the paper provides new insights both to the scientific community and policy makers; this can serve as guidance for selecting adequate instruments that simultaneously ensure a stable security of supply and the extension of renewables in a sustainable manner.

In the next section we present current alternative views on the need for a new market design, as well as review relevant energy models in the literature. Section 3 presents the theoretical approach to the development and subsequent analysis of a new market model, based on the considerations put forward in Section 2. Section 4 analyses the need and practicality of new market designs using empirical data. Finally, Section 5 summarises our main findings.

## 2. Electricity market designs: mechanisms and adequacy

### 2.1. The German energy-only market: concepts and background information

As the current electricity market in Germany is operating on the basis of actual (rather than potential i.e. available capacity) production, it is commonly referred to as an energy-only market. In relation to the total amount of electricity consumed, a relatively small proportion is traded on the spot market; the greater part is procured by direct supply contracts (Garz et al., 2009). However, regardless of the form of the contract, all prices are geared to those on the spot market, as deviations would provide scope for arbitrage.

In line with microeconomic theory, an operator offers the output of a power plant at its marginal cost (Varian, 2004). On the energy exchange market, all bids are collected and ranked in an ascending order according to individual marginal costs (offering prices; see Bode and Groscurth, 2006). This produces a prioritisation scheme for power plants with different marginal costs, which is termed the merit order (MO), and corresponds to the supply curve of the electricity market. The energy exchange accepts bids, beginning with the lowest ones, until the demand-side quantity of electricity is met (Henriot and Glachant, 2013). The price of electricity is determined by the last bid accepted that satisfies demand (Wirth, 2013). According to peak load pricing theory, the peak demand price must be above the marginal cost of the most expensive type of power plant in order to ensure that these plants can cover their capital costs (Pillai, 2010). Basically, the marginal costs of a conventional power plant depend upon its net efficiency, the respective fuel and $CO_2$ emission costs, and other variable operating and maintenance costs (Lang, 2007). Fig. 1 displays the MO (supply curve) for conventional power plants and the corresponding demand for electricity on the energy exchange spot market.

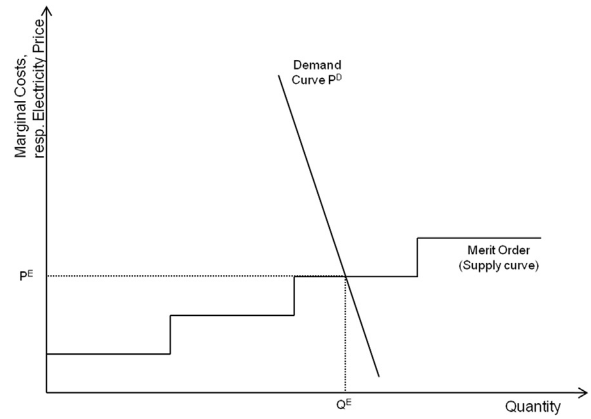


**Fig. 1.** Schematic supply and demand curve on the spot market.

RE in Germany is largely incentivised through the country's Renewable Energy Sources Act ("Erneuerbare-Energien-Gesetz" - EEG). Under this act, operators of renewable energy power plants are paid for the generation of their supplied electricity (by the transmission network administrators) according to fixed tariffs set by the state (Lesser and Su, 2008; Couture and Gagnon, 2010; Schleicher-Tappeser, 2012). Electricity from RE is generally subject to a prioritised arrangement in Germany. Under this arrangement, the operators of public transmission networks must positively discriminate in favour of electricity generated by renewables, before purchasing electricity generated from other energy sources (Federal Ministry of Justice, 2014). Since the introduction of the amended EEG in 2014, new RE power plants are expected to carry out a mandatory level of direct selling depending on their installed capacity. On the exchange market, this green energy is traded on an equal footing with conventionally produced electricity and sold at the same price.

In general, RE has minimal marginal costs in the form of variable operating and maintenance costs. Typically, when the electricity generated from RE is traded on the energy exchange market, this leads to significant changes in the MO (Paraschiv et al., 2014). The diagram below shows that, owing to its marginal costs close to zero, the additional supply of RE is at the leftmost end of the MO-curve, thereby resulting in the original supply function shifting to the right and the equilibrium electricity price falling - this is commonly referred to in the literature as the merit order effect (MOE) (Sensfuß et al., 2008; Felder, 2011; Henriot and Glachant, 2013). The MOE of RE is dependent upon the gradients of the supply and demand curves on the one hand, and the quantity of RE provided on the other.

This downward effect of RE on spot market prices can be observed even when the generated quantity of RE is not traded on the energy exchange market. Owing to the aforementioned obligation of transmission network operators to give priority to RE during electricity procurement, the infeed of electricity generated from RE results in a reduced demand on the spot market (when the latter is not traded on the energy exchange market, see Felder, 2011). In this context, one should note that the demand for electricity is relatively inelastic with respect to changes in prices (at least in the short term – this corresponds to a steep demand curve, as depicted in Figs. 1 and 2; see also Sioshansi, 2008).

### 2.2. A Review of the literature

There is an ongoing heated debate on whether energy-only markets offer sufficient economic incentives to permanently ensure a stable electricity supply. Elberg et al. (2013), Cramton, Ockenfels (2012) and Joskow (2006) claim that the energy-only market can fail due to a very price-inelastic demand. They point out that the vast majority of customers are not "smart metered" (i.e. not using a time-of-use metering

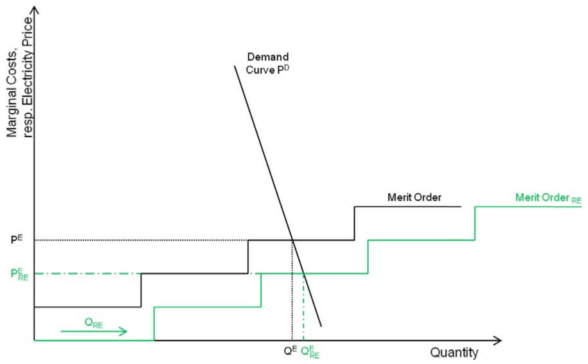


**Fig. 2.** Effects of an increasing amount of renewable energy on the spot market.

structure, and, hence, their actual electricity purchases per hour are not measured), which prevents billing them according to the current (hourly) price of electricity on the spot market. Instead, these customers pay a pre-defined average electricity price for their total consumption that does not reflect current availability or the actual price of supply. Accordingly, there is no incentive for them to reduce demand in times of very limited supply, which may result in blackouts or forced outages. Likewise, Cramton et al. (2013) identify low demand flexibility as a central problem of electricity markets, since consumer unawareness of real-time prices impedes adequate reactions and, thus, results in a highly price-inelastic demand. They add that this, in turn, hinders establishing market-clearing prices, which represent a crucial prerequisite for efficient generation capacity (and its corresponding mix). According to Boot and van Bree (2010), smart meters can stimulate demand responses to varying prices, and specific contracts may enable consumers to level off peaks and troughs. Therefore, they recommend to view smart meters as an integral part of existing infrastructure, rather than as an object of individual choice.

In contrast, Müsgens and Peek (2011) and Dyllong (2013) argue that, at least in Germany, approximately 60% of all customers can actually react to price signals on the current market. They support this by pointing out that, in the German market, a significant share of consumers already have smart meters or an appropriately configured electricity purchase agreement that enables them to influence price developments on the wholesale market.

A further, often cited, argument to support the view that the existing energy-only market is not sufficient to ensure supply security in the long term is the so-called "missing-money" problem (Rodilla and Batlle, 2012; Hogan, 2005; Tietjen, 2012). This term refers to the fact that the price levels determined on energy-only-markets (according to the merit-order-principle described above) are too low to provide sufficient incentives for investment in new power plants. According to Cramton et al. (2013), wholesale markets fail to generate prices that reflect the opportunity cost consumers place on electricity consumption in times of fully utilised capacity. The term Value of Lost Load (VoLL) refers to the price consumers would be willing to pay to avoid blackouts (Tietjen, 2012). However, since they are unable to recognise situations of extreme scarcity, the VoLL cannot influence prices adequately. As a result, merit-order prices with an inelastic demand are too low to cover the cost of all power plants involved.

In addition, the ever-increasing feed-in of RE inevitably leads to declining electricity prices on the wholesale market. Cludius et al. (2014) estimate the price effect of wind and photovoltaic electricity generation in Germany between 2008 and 2012, and find that each additional GWh of renewable electricity fed into the grid reduces the price on the electricity day-ahead market by 1.1–1.3 €/MWh. In 2006, the associated total value of the price effect resulting from RE exceeded the net support payments for RE generation according to EEG (Sensfuß et al., 2008). While consumers benefit from the increase in renewable electricity, the operators of conventional power plants pay the bill of this structural shift: the profitability of conventional plants suffers significantly from lower spot market prices (Henriot and Glachant, 2013). Milstein and Tishler (2009) also show that, due to optimal responses of electricity producers to demand fluctuations, underinvestment in competitive electricity markets is inevitable: instead of building new capacity that remains idle during long periods of time, producers let the electricity price spike. For this reason, in many markets a price cap is introduced (Elberg et al., 2013). However, if this price cap is set too low, the operators of peak load power plants, which are exclusively used during times of high demand, in turn do not earn sufficient margins.

The "missing money problem" is also recognised by Müsgens and Peek (2011), but they add that its impact can be mitigated by the use of different flexibility and adaptation mechanisms both on the supply and demand side. On the supply side, they list increasing electricity imports, the utilisation of emergency generators, the reactivation of power plants in cold reserve, and retrofit measures for existing facilities to extend their service life and increase their efficiency. On the demand side, instruments for ensuring short-term security of supply include a reduction of exports, the increased use of smart metering and improved efficiency in energy use (efficient equipment) (Gottstein and Schwartz, 2010).

## 3. Methodological approach

In this section we present the theoretical underpinnings of our model of the German electricity market. We develop a reference electricity market design that represents the status quo, as well as a new market design. An underlying key assumption is that conventional electricity is fully traded on the spot market. Furthermore, there is no transnational trade in electricity – we focus exclusively on the German market. Section 3.1 describes the model that represents the status quo of the electricity market. Section 3.2 describes the modelling of our new market design.

### *3.1. Load duration curve model*

In order to analyse the impact of a new electricity market design on the economics of conventional power plants, a basic electricity market model (the Load Duration Curve Model, LDCM) is taken as a starting point (Poulin et al., 2008; Turner and Doty, 2007; Geiger, 2010). The LDCM is based on the Residual Load Duration Curve (RLDC) and the MO. It allows to determine electricity prices and to calculate contribution margins of power plants. According to the RLDC, the hourly electricity demand in MW for the entire 8760 h a year is depicted in descending order. The quantities demanded correspond in each instance to total demand less the RE infeed RE. Fig. 3 depicts a typical RLDC for the German electricity market.

A typical MO-curve of conventional power plants (for the German electricity market) is depicted in Fig. 4. Corresponding to the

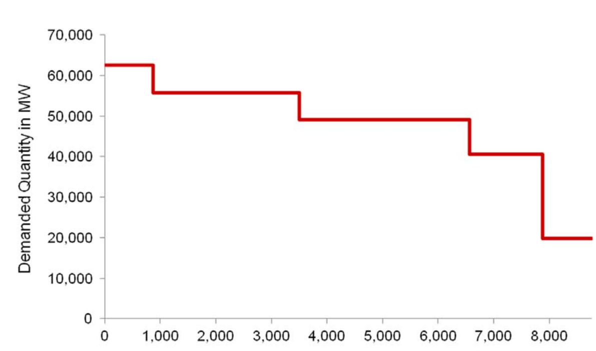


**Fig. 3.** Residual load duration curve (Own depiction based on EEX, 2010–, 2013, EEX, 2010– 2014).

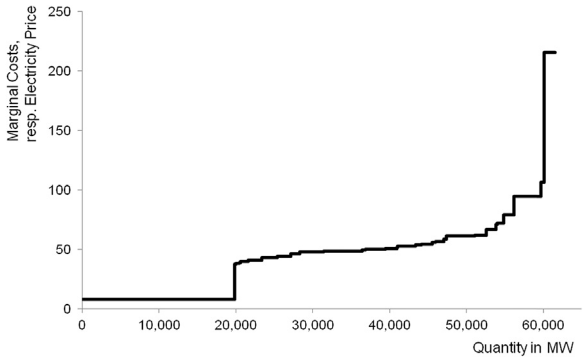


**Fig. 4.** Merit order curve (Own depiction based on WestLB, 2009).

methodology described earlier, the MO has been created according to increasing marginal costs of available power plant capacities.

By linking RLDC and MO, it is possible to determine the applicable prices for electricity (for the hourly amounts of demand in a year). Electricity prices for each MW supplied, as identified from the MO, are assigned to the respective electricity demand of the RLDC. On that basis, electricity prices for the demanded quantities are allocated to the corresponding duration in hours (of equivalent demanded quantities). This derivation leads to the so-called Price Duration Curve (PDC). Fig. 5 graphically summarises such a procedure.

Based on the PDC, the contribution margins of each power plant in the spot market can be determined by means of integral calculus. Fig. 6 displays the Price Duration Curve (PDC) together with the marginal cost curve ($MCPP_i$) of a power plant $PP_i$.

The contribution margin (CM) of power plant ($PP_i$) per MW of installed capacity is given by the following equation:

$$CMPP_i = \int_0^{d_i} [PDC(x) - MCPP_i(x)]\,dx, \tag{1}$$

where x = number of yearly production hours
$d_i$ = production hours (power $\text{plant}_i$).

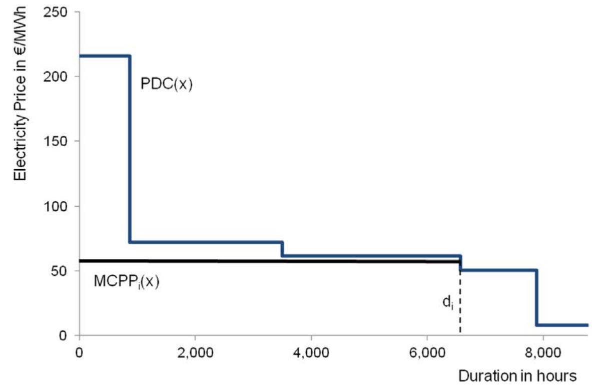


**Fig. 6.** Price Duration Curve and Power Plant's contribution margin.

Taking into account each power plant's full capacity ($CPP_i$) in MW, the total contribution margin (TCM) of ($PP_i$) can be defined as follows:

$$TCMPP_i = CPP_i \bullet CMPP_i. \tag{2}$$

Taking into consideration the annualised fixed costs of a power plant ($FCPP_i^n$), the net present value (NPV) of a power plant is now given by:

$$NPVPP_i = \sum_{n=1}^{n_{op}} \left(\frac{TCMPP_i^n - FCPP_i^n}{(1+dr)^n}\right), \tag{3}$$

where superscript n refers to the year of production, $n_{op}$ represents the operating lifetime of $PP_i$ and dr represents the discount rate.

### 3.2. New electricity market design

The new electricity market design is based on the idea that both the electricity price and the profitability of conventional power plants are significantly dependent on the level of adaptation of conventional power plants to RE supply. Against this background, a methodology is utilised that makes it possible to model the most cost-effective composition of a conventional power plant complex. The upper chart of

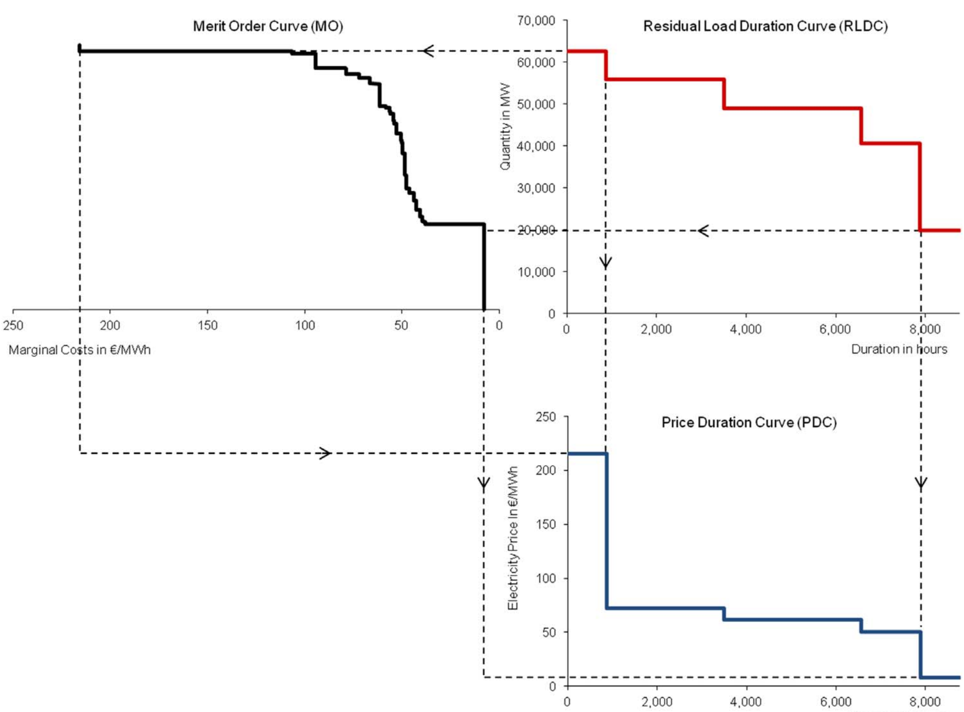


**Fig. 5.** Load Duration Curve Modell (Own Depiction).

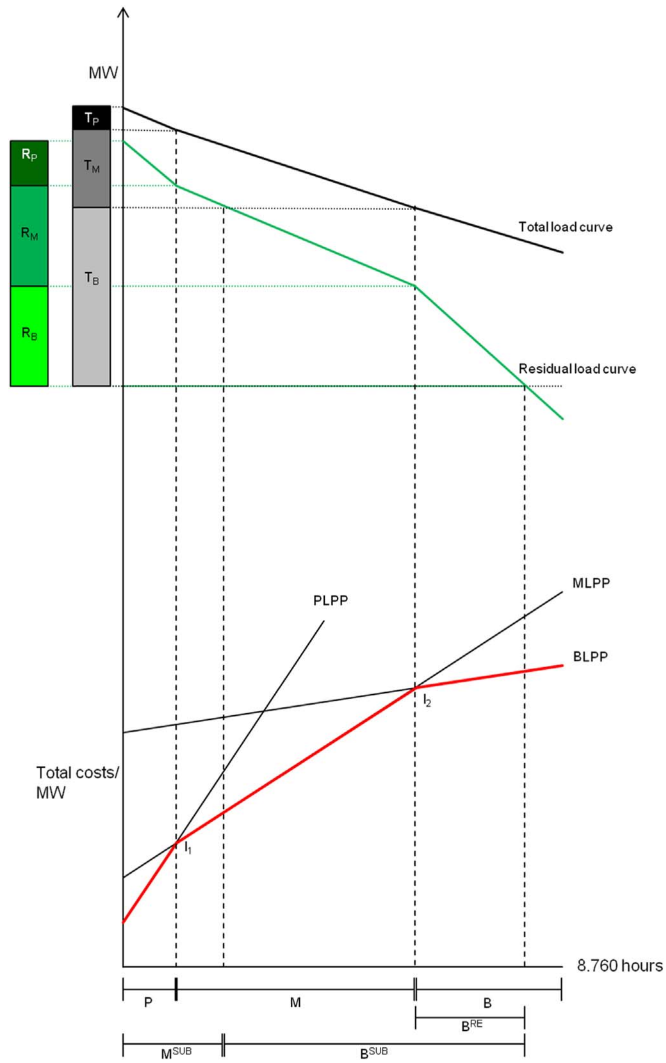


**Fig. 7.** Effects of RE on the optimal composition of the complex of power plants *(Own Depiction based on* Nabe, 2006*,* Weber and Woll, 2007*,* Wissen and Nicolosi, 2008*,* Miera et al., 2008*,* Fürsch et al., 2014*).*

Fig. 7 depicts the hourly electricity demand in MW in descending order for the entire 8760 h of a year. While the grey curve depicts the total electricity demand (Total Load Duration Curve or LDC), the green curve shows the difference between total demand and the infeed from RE. This remainder of the demand is equivalent to the Residual Load Duration Curve (or RLDC). In the bottom part of Fig. 7, the total annual cost per MW of base-load (BLPP), medium-load (MLPP) and peak-load power plants (PLPP) are shown as a function of their periods of use. Typically BLPPs are nuclear or lignite power plants that are built to operate the entire year on a full-time basis. Hard coal, Combined Cycle Gas Turbines (CCGT) and Gas Turbines (GT) can be considered as MLPPs. These power plants have lower starting- and shut-down times and can thus be utilised more flexibly. PLPPs, such as oil power plants, are able to operate particularly flexibly and are hence utilised to meet the highest demands during a day. The intersections of the three curves with the ordinate represent the annual fixed costs for each class of power plants. The slopes of the curves reflect the marginal production costs.

The intersections $I_1$ and $I_2$ of the curves delineate the periods of use, during which a change of power plant class leads to lower total annual costs. The red curve (efficiency cost curve) indicates the type of power plant technology that can satisfy the respective levels of demand for a given annual number of hours at the lowest total cost. The optimal composition of the conventional power plant complex as shown in the top left of Fig. 7 can be determined by transferring the intersections $I_1$ and $I_2$ to the demand curves. The quantities $T_B$, $T_M$ and $T_P$ in the grey bar represent the optimal mix of conventional BLPP, MLPP and PLPP for an electricity market that does not include RE. The capacities $R_B$, $R_M$ and $R_P$ in the green bar represent the most cost-effective mix of conventional types of power plants satisfying the RLDC, i.e. for a power system with a significant proportion of RE.

Assuming that the complex of conventional power plants is optimally adapted to the infeed of electricity from RE, the corresponding (long-term equilibrium) electricity price can be derived from the efficiency cost curve shown in red (Fig. 7). The slope of this curve corresponds to the marginal cost of the most cost-effective type of power plant for each respective amount of electricity demanded. The example provided by Fig. 7, therefore, indicates that (regardless of the supply of RE) the price of electricity corresponds to the marginal costs of a PLPP and MLPP during the P and M time intervals respectively (apart from the peak load pricing mechanism). By contrast, the number of hours, during which the marginal costs of BLPP determine the price of electricity, differs depending on the amount of RE infeed. Without taking RE into account, the price of electricity during the B time interval is equal to the marginal costs of a base load power plant. The average price of electricity $P^T$, given the optimal adaptation (to RE) of a conventional complex of power plants to the LDC, can thus be described as follows:

$$P^T = \frac{MCP + MCM + MCB + Peak}{8.760}, \tag{4}$$

where MCP = Marginal Costs of PLPP
MCM = Marginal Costs of MLPP
MCB = Marginal Costs of BLPP
Peak = Peak Load Pricing.

As described above, by generating electricity from RE, a part of the base load is covered, consequently, the RLDC becomes zero or negative during certain hours with high RE production (above $B^{RE}$). The price of electricity $P^{RE}$, therefore, corresponds to the marginal cost of a BLPP only during the $B^{RE}$ time intervals (and for operating hours exceeding $B^{RE}$ the price of electricity becomes zero):

$$P^{RE} = \frac{MCP + MCM + B^{RE}MCB + Peak}{8.760}, \tag{5}$$

because $B^{RE} < B$, $P^{RE} < P$. In summary, it can be shown that for an optimal adaptation of a conventional power plant complex, the infeed of RE leads to a reduction in the average price of electricity.

The impact of a sub-optimal adaptation of a power plant complex to the infeed of RE can also be illustrated using Fig. 7. The power plant complex depicted in the grey bar (top part of Fig. 7), which has been optimally configured for the LDC, serves here as a point of reference. In contrast to the initial approach, however, we now make the assumption that a strong expansion of RE is successful; as a result, the actual demand corresponds to the RLDC depicted in green. In such a scenario, there is a significant excess capacity of BLPPs. This implies that the number of hours, where the relatively low marginal costs of a BLPP determine the price of electricity, is now clearly larger (see $B^{SUB}$ area, where $B^{SUB} > B$). During the remaining amount of hours $M^{SUB}$, the price corresponds to the marginal cost of an MLPP. The existing PLPPs are no longer needed and do not, therefore, determine the price at any time. In addition, the existing excess capacity impedes shortage pricing during peak loads. Summing up, a sub-optimal adaptation of a power plant complex to the infeed of RE results in a significantly lower average price for electricity (denoted by $P^{SUB}$):

$$P^{SUB} = \frac{M^{SUB}MCM + B^{SUB}MCB}{8.760}, \tag{6}$$

where $P^{SUB} < P^{RE} < P$.

The new market design incorporates these interdependencies. While the supply side initially consists of the same conventional power plants as in the reference market design, for each consecutive year, the complex of power plants is modelled to be optimally adapted to RLDC (thus representing the most cost-effective composition of different power plants). As a next step, for each of the 8760 h per year, the most cost-effective power plant technology is selected, allowing us to derive the efficiency cost curve. As demonstrated earlier on in Fig. 7, at the kinks along the efficiency cost curve, the corresponding threshold number of operating hours are linked to the RLDC in order to calculate the equivalent amount of installed capacity of each power plant technology. This corresponds to the optimally adapted (to RE supply) complex of power plants, which is then compared to existing real conventional power plant capacities. The capacities of those power plants in the market are allocated on the basis of optimal adaptation guidelines. In case there is need for additional capacity of a particular power plant technology, these quantities are complemented by the excess capacity of remaining technologies, again according to optimal adaptation guidelines.

In case that excess capacities fail to meet the entire demanded quantity, an investment (in additional capacity) is made to optimally fill the gap. This assumes that necessary investments materialise within the next year (in reality, one might a expect a longer time lag between the decision to build a new power plant and the time it goes into operation– relaxing this assumption does not alter substantially our later findings regarding observed differences between the two electricity market designs). If, on the contrary, the existing power plant capacity exceeds the optimal adaptation level, redundant power plants are not allowed to offer their capacities in the market. Based on this allocation of production capacities, the profitability of power plants (that are in the market) is again modelled by utilising the LDCM.

## 4. Simulations

### 4.1. Data

Our analysis considers the period between 2015 and 2034. The forecast of German electricity demand is based on reported data from the European Energy Exchange (EEX, 2010–2013). For the years 2010–2013, the hourly average electricity demand is calculated, which is then projected to remain stable until 2034. It is assumed that demand-increasing developments (e.g. in the form of electric mobility) are counterbalanced by increasing energy efficiency (later on, we relax this assumption and carry out a sensitivity analysis). Assumptions concerning the future installed capacity of RE are based on the expansion goals of the German Federal Government (Federal Ministry for the Environment, Nature Conservation, Building and Nuclear Safety, 2012). As to availability, bioenergy and geothermal energy are assigned a customary availability factor of 0.9, while the availability factor of hydroenergy is 0.4 (Möst et al., 2012). The availability factors of solar and wind energy are calculated based on time series analyses. For this purpose, the real hourly production of solar and wind energy for the years 2010–2014 is compared to the maximum potential production per hour (EEX, 2010–2014). The future hourly production of RE is then represented by the product of the assumed future capacity installed and the respective average hourly availability factor. Subtracting the total hourly RE production from the corresponding total demand results in the residual demand. This quantity depicts the demand that is left to be met by conventional power plants. The depiction of the conventional complex of power plants is based on data from the Federal Network Agency (2015). To account for any unavailability of plants, as well as start-up and shut-down periods, the installed capacity of each power plant is reduced by 10% (Enervie, 2014). Economic and technical data of existing power plants are mainly based on empirical data that have been collected within the research department of the German bank WestLB (WestLB, 2009) (any missing data of existing power plants are determined by linear interpolation).

Through the application of the LDCM (see Section 3), the profitability of each German power plant is determined for the years 2015–2034 (at each point in time, a fictive complex of power plants is modelled for the next ten years that follow). During this period of time, power plant shutdowns according to their assumed life cycle are taken into consideration. To account for peak load prices, the prices on the spot market are increased by 5%. A weighted average cost of capital equal to 7.14% is used as the discount rate (Enervie, 2014). On this basis, the NPV of each power plant (at each point in time)is calculated for the fictive time span of ten years. In addition, an optimisation modelling is executed in order to identify the NPV maximising investment capacity in MW in each of the following power plant technologies: Lignite, Hard Coal, Combined Cycle Gas Turbines (CCGT) and Gas Turbines (GT).

Apart from power plants that are taken out of production due to technical reasons, the decommissioning of power plants due to economic considerations is modelled as well. In this context, we assume that a power plant is shut down in case its NPV is negative for five years in a row. Both power plant shutdowns, as well as new investments, are assumed to take effect in the subsequent year, respectively. Finally, Fig. 8 shows the total cost curves of the six power plant technologies under consideration (i.e. nuclear energy, lignite, hard coal, CCGT, GT and oil) for the starting year 2015.

### 4.2. Model-based results

In this section we compare the model-based results of both the reference and the new market mechanisms. The presented simulations are based on the benchmark projections (constant electricity demand over time, increasing $CO_2$ prices (on average 8% per year), a discount rate of 7.14% and an electricity price markup of 5%).

#### 4.2.1. Development of conventional power plant capacity

Fig. 9 displays the total installed capacity of conventional power plants, as well as the RLDC between 2015 and 2034 for the reference (r) and the new market mechanism (n). In the reference market mechanism, a very large number of power plants are expected to shut down after five years. As Fig. 10 reveals, the reason for this decommissioning of capacity is largely due to economic inefficiency and only partly to power plants reaching the end of their lifecycle. For the remaining years, there is no further decommissioning as a consequence of economic inefficiency, which is mainly driven by nuclear energy being phased out (with the last nuclear power plants shutting down by 2022; see also Bundesgesetzblatt, 2011). Overall, investments generally remain low – investment in lignite and CCGT power plants, in particular, lead to a NPV maximising solution only for certain years. The results indicate that, in the reference electricity market design (that tries to capture the current market conditions as close as possible), there are not sufficient economic incentives that guarantee an adequate amount of power plants to meet residual load.

The new electricity market design reveals a different picture. For the majority of years, there is a sufficient amount of conventional power plant capacity to meet residual load. It is only for very few years that supply falls below demand. As described in the previous section, in the new electricity market design, investments are not made based on a modelling of NPV maximisation, but instead on a complex of conventional power plants optimally adapted to residual load. For this reason, in each year following disinvestments due to economic inefficiency, there is a sufficient amount of replacement investment to meet demand. In summary, the new electricity market design leads to a higher level of supply that, in most cases, is sufficient to meet demand.

#### 4.2.2. Average annual electricity price

Fig. 11 shows the average annual electricity price both for the

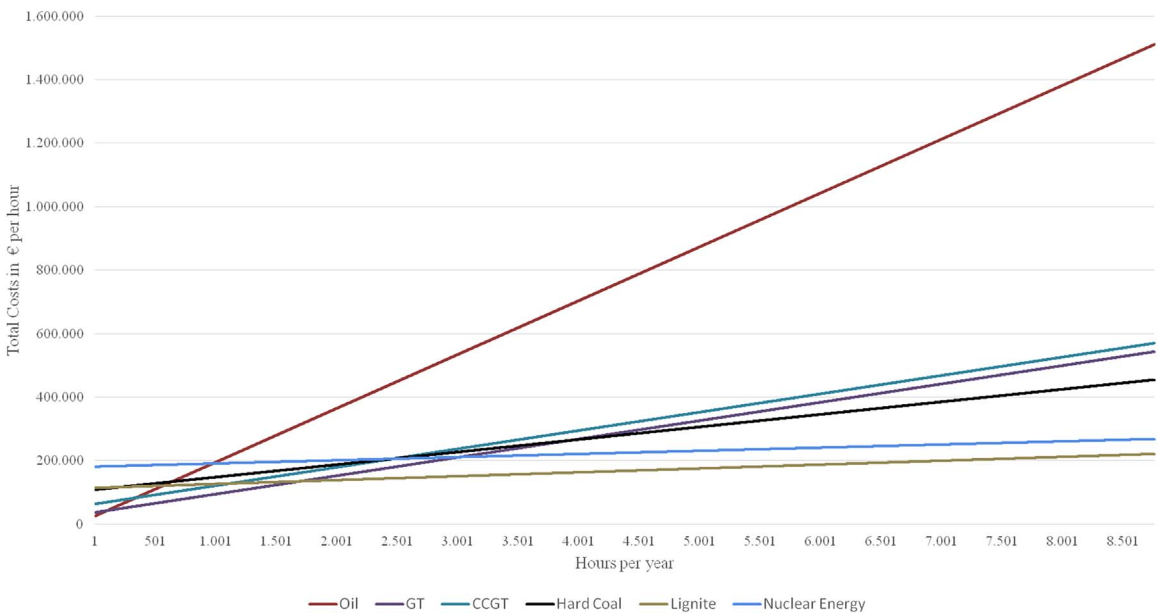


**Fig. 8.** Total cost curves of conventional power plants in the year 2015 *(Own Depiction based on* Elberg et al., 2012 *and WestLB)*.

reference market design and the new electricity market design.

As one can see, the hypothesis that a conventional complex of power plants that is optimally adapted to residual load always leads to a higher average electricity price (compared to a sub-optimally adapted complex) cannot be confirmed by the empirical results. Fig. 12 demonstrates that, in the new electricity market design, the average electricity price is mostly lower than in the reference market design. In 2020, there is a significant increase to more than €150 per MWh due to large disinvestments (of more than 40.000 MW in the previous year). Due to these decommissioning activities, the installed capacity in 2020 is not sufficient to meet demand. As a consequence, all remaining power plants in the market are operating at full capacity all year round, so that the price is always set by the 'high marginal cost' oil power plants. In the following years, the price returns to a level of around €25 per MWh because of strong investments primarily in 'low marginal cost' lignite power plants. This price level remains quite constant apart from the years 2026 and 2032, during which the price increases to more than €150 per MWh. These increases are again caused by large disinvestments in the previous years, which lead to a lack of capacity in the market (and once again, subsequent replacement investments help the average electricity price return to lower levels).

To sum up, there is no support of the hypothesis that the new electricity market design leads to a higher electricity price. On the one hand, the utilisation of power plants in the new market design is strictly oriented towards an optimally adapted complex of power plants. This is simply because it would be unrealistic to exclude existing power plants in the market design. On the other hand, the average electricity prices in the reference market design tend to be biased, since during the period between 2020 and 2034, energy demand exceeds supply, forcing hence all power plants of a particular year to operate at full capacity. Therefore, the number of hours per year, where the price is set by 'very high marginal cost' power plant technologies is also outstandingly high.

#### 4.2.3. $CO_2$ emissions

In order to evaluate the actual difference in $CO_2$ emissions between the new and the reference electricity market designs, it is necessary to calculate the annual $CO_2$ emissions per MWh. This is because, in the reference market design, the installed conventional power plant capacity is mostly insufficient to meet residual load, while, in the new electricity market design, the opposite holds (see Fig. 9). Fig. 12 shows

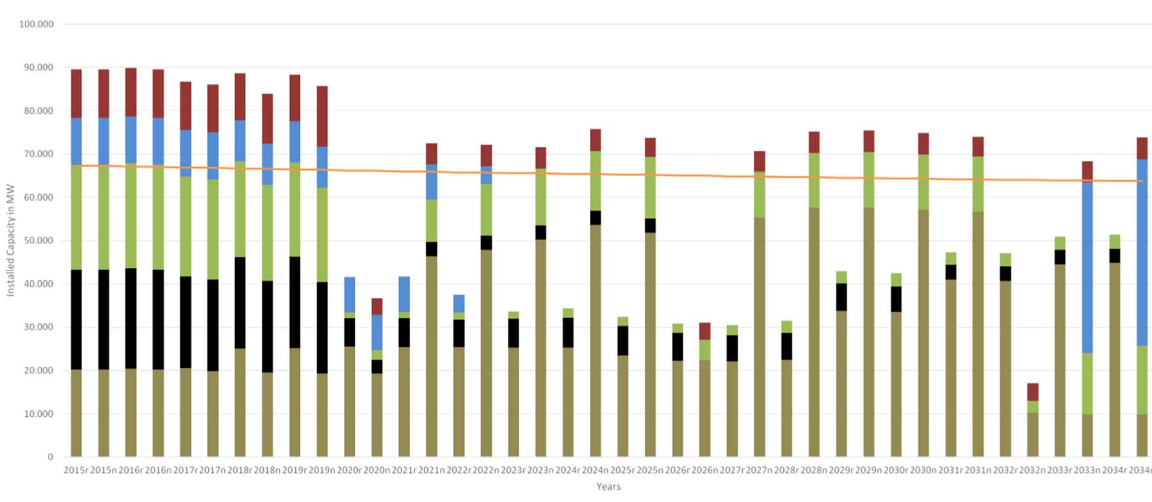


**Fig. 9.** Installed conventional power plant capacity and residual load duration curve, reference- and new electricity market design, benchmark projection.

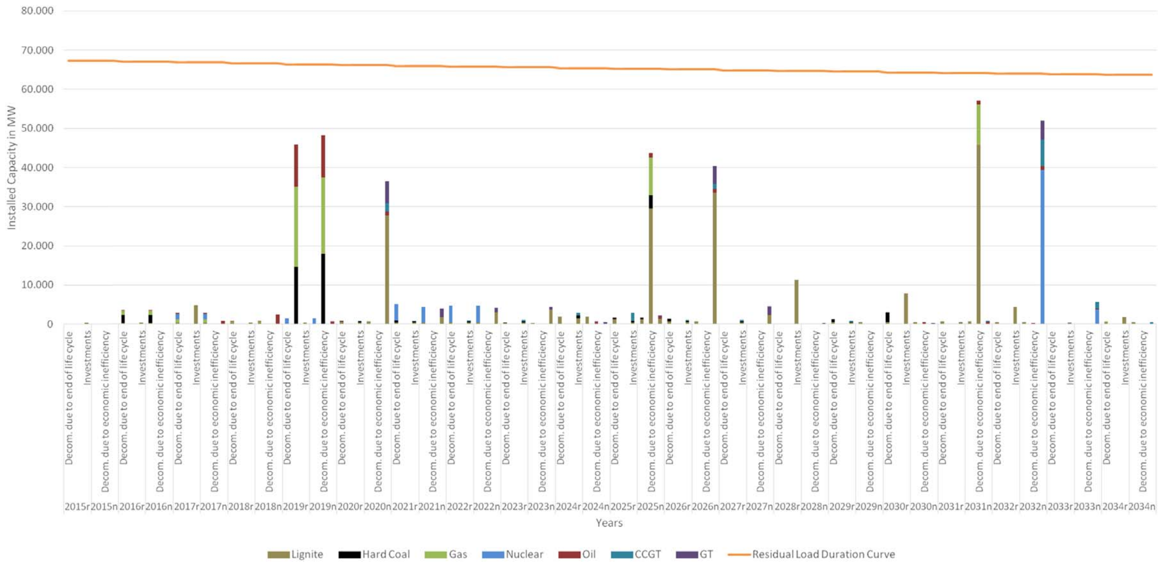


**Fig. 10.** Decommissioning and investment in conventional power plants and residual load duration curve, reference- and new electricity market design, benchmark projection.

that the $CO_2$ emissions per MWh in the two market designs start more or a less at the same level during the first three years. Thereafter, the $CO_2$ emissions per MWh produced in the new electricity market design (green curve) are consistently between 5 and 10 per cent lower than in the reference market design (black curve). For the last three years of the period under consideration, the $CO_2$ emissions per MWh produced in the new market design decline rapidly due to investments in low carbon-emitting technologies.

### 4.2.4. *Total costs of conventional electricity production*

The total costs of conventional electricity production consist of the annualised fixed costs of power plants and the product of marginal costs, operating hours and available power plant capacity. Due to the differing amounts of electricity produced, it is meaningful to compare the reference and new electricity market designs by looking at the respective cost per MWh. Fig. 13 shows that these costs are almost on the same level of around €40 per MWh between 2015 and 2029. Subsequently, total costs per MWh rise in 2030 for both market designs, due to the increasing cost of $CO_2$ emissions.

Summing up, the assumption that a complex of conventional power plants better adapted to residual load necessarily leads to higher cost efficiency cannot be confirmed by the empirical results.

### 4.2.5. *Profitability of conventional power plants*

The average profit per MW of installed capacity for each type of power plants is depicted (for the reference- and new electricity market designs) in Fig. 14. For the reference electricity market design, lignite power plants are consistently profitable over the entire period under investigation. Nuclear energy power plants are also consistently profitable, though on a lower level, until they become decommissioned as they reach the end of their lifecycle in 2022. With the highest marginal costs, oil power plants do not have sufficient operating hours to achieve positive profitability, and, as a result, they become decommissioned after five years of operation in 2020. Gas and hard coal power plants display fluctuating profitability. In the first years, hard coal power plants only reach slightly positive profitability and corresponding figures for gas power plants are consistently negative. This is because gas and hard coal power plants are often setting the price, which results in low contribution margins. With increasing $CO_2$ emission costs in later periods, this pattern is somewhat reversed. Between 2021 and 2028, both types of power plants are operating with a profit thanks to a combination of low capacity and moderate $CO_2$ emission costs.

The new electricity market design shows a different picture. In 2020, 2026 and 2032 (years characterised by a substantial lack of capacity in the market, see Fig. 9), profitability drastically increases up to €1.2 million per MW of installed capacity. This is because power plants in these years are able to operate full time, which results in high contribution margins. With the exception of lignite and nuclear energy power plants during the first five years and oil power plants in the remaining period, all other technologies operate with a loss. This is because (for most years) a very high proportion of base load power plants operate in the market. These technologies are characterised by low marginal costs, so that prices become too low to reach sufficient contribution margins. Overall, the simulation results confirm that the

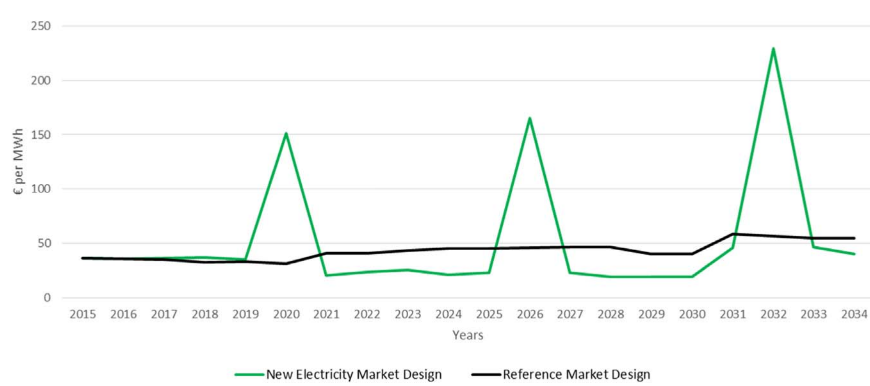


**Fig. 11.** Average annual electricity price, reference- and new electricity market design, benchmark projection.

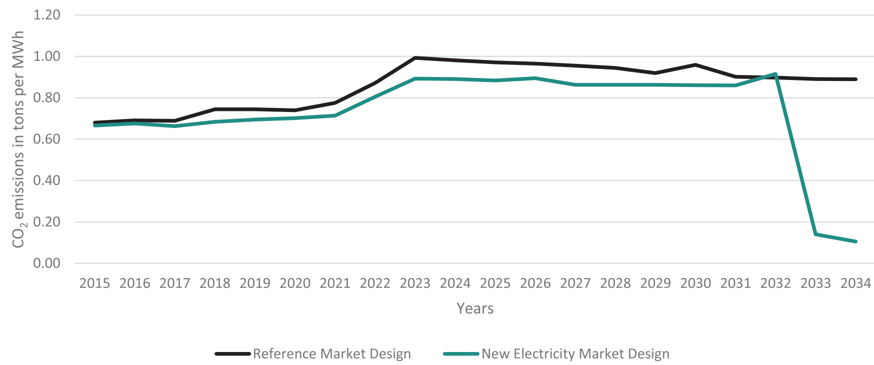


**Fig. 12.** $CO_2$ Emissions per MWh, reference- and new electricity market design, benchmark projection.

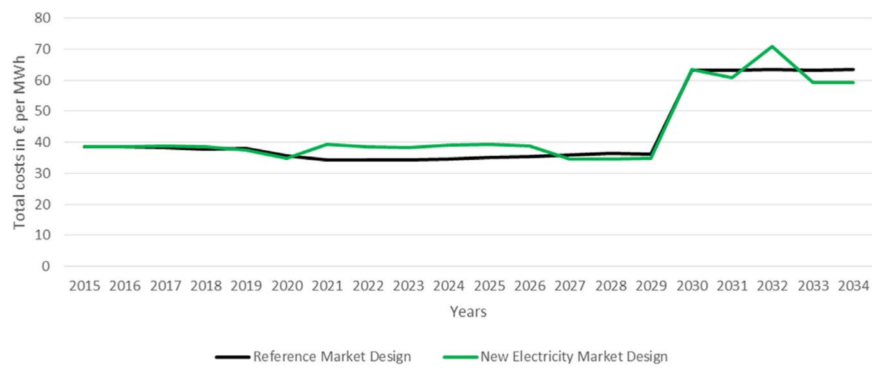


**Fig. 13.** Total costs in € per MWh, reference- and new electricity market design, benchmark projection.

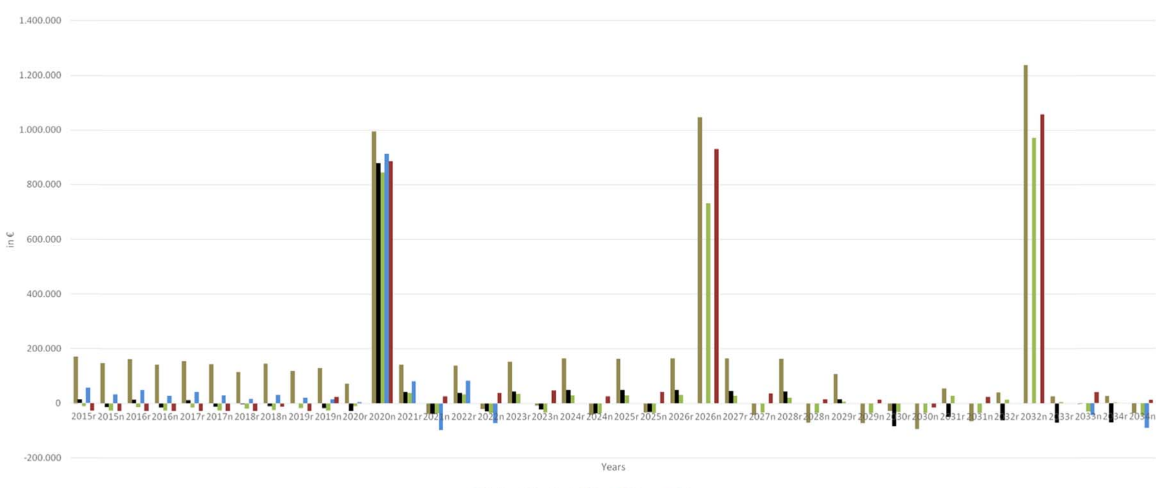


**Fig. 14.** Average profit per MW installed capacity, reference- and new electricity market design, benchmark projectio.

new electricity market design results in lower power plant profitability than the reference market design. Thus, a complex of power plants optimally adapted to residual load does not lead to an improved economic environment.

#### 4.2.6. *Sensitivity analysis*

Finally, we carried out a sensitivity analysis of the reference and new market mechanisms (results available from the authors upon request) for different electricity demand (benchmark, constant, $+/-$ 0.50%/year) and $CO_2$ price scenarios (benchmark, constant, doubling, halving). Overall, the results of the sensitivity analysis show that increased $CO_2$ emissions costs do not reduce the profitability of power plants (as these costs can be transferred to electricity prices). Modest variations in electricity demand also do not have a substantial effect on the installed capacity of conventional power plants. We found electricity prices to be largely insensitive to the changes in electricity demand and carbon emission costs. We also considered alternative scenarios corresponding to a halving of the discount rate as well as a doubling of markup prices. These alternative scenarios improve profitability of power plants and thus installed capacity significantly in both market designs - while increased markup prices increase the average electricity price by a similar magnitude, a lower discount rate has the opposite effect.

## 5. Conclusions

There is a continuously increasing infeed of renewable energy in the German electricity market. However, due to the intermittent nature of renewable energy supply, a significant amount of conventional power plants is still needed to ensure uninterrupted electricity supply. As a result of its close to zero marginal costs (and hence drop in the average electricity price), renewable energy leads to a displacement of conventional power plants, which poses a threat to the security of electricity supply in the medium- to long-term. Against this background, researchers and policy-makers pay increasing attention to the suitability of the current electricity market design and potential changes to address the current shortcomings.

In this paper we developed a new market design based on the idea of a complex of conventional power plants that is optimally adapted to residual load. In theory, such a composition of power plants always leads to the highest possible average electricity price and the most cost efficient supply of electricity. We provide simulation results based on empirical data that refute the hypothesis that an optimised complex of conventional power plants is more cost-efficient and leads to a higher average electricity price. Our analysis reveals that the mere orientation of existing power plants to an optimally adapted solution is not sufficient to achieve an improved market environment and ensure uninterrupted power supply.

Our analysis has shown that, under the current market conditions, a large amount of power plants cannot operate profitably, and, as a result, the security of supply cannot be guaranteed in the medium to long-term. This outcome emphasises the need for further research and increased policy attention. We highly recommend that policy makers reconsider their current RE and conventional energy policy. Policy makers should concentrate attention on the economic effects of different approaches to achieve RE expansion and security of supply; this will assist them in obtaining more accurate estimates about the monetary costs and environmental impacts of electricity generation in the future.

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