Charles University in Prague

Faculty of Social Sciences
Institute of Economic Studies

MASTER THESIS

Capacity remuneration mechanisms and the optimal electricity market design

Author: Bc. Ladislav Sobotka

Supervisor: Mgr. Ondřej Strecker

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Declaration of Authorship

The author hereby declares that he compiled this thesis independently, using only the listed resources and literature. This thesis has not been used to obtain any other degree.

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Prague, July 31, 2013

Signature

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Abstract

EU electricity markets are facing fundamental challenges as a result of the EU goal to increase the share of the renewable energy sources. This policy negatively influences profitability of the conventional producers known theoretically as “missing money” problem. As the conventional plants are crucial to offset the variability of renewable, this policy puts the stability of the whole grid at risk in long-term under the current electricity market design.

The thesis tests and confirms the hypothesis that there is currently a “missing money” effect on the German energy market through a dynamic programming model. Secondly, three types of the capacity remuneration mechanisms (CRMs) are implemented (capacity payments, strategic reserve and capacity auction) in order to deal with “missing money” which mostly eliminates the missing money problem depending on the setting. The most effective CRM seems be the capacity auction model as the price is set dynamically by the market players and not arbitrarily by central regulator. The thesis further supports the creation of the demand flexibility scheme due to the expected low costs.

Author´s email: l.sobotka@cenrum.cz

Supervisor´s email: strecker.o@seznam.cz

Abstrakt

Evropský trh s elektřinou má před sebou výzvu v podobě adaptace na vyšší podíl obnovitelných zdrojů. Tato politika negativně zasáhne ziskovost konvenčních výrobců elektřiny a tento efekt se v literatuře nazývá problém „chybějících prostředků“. Protože jsou konvenční výrobci nezbytní pro vyrovnávání volatilních obnovitelných zdrojů, může tato politika z dlouhodobého hlediska poškodit stabilitu sítě.

Práce testuje a potvrzuje hypotézu o přítomnosti problému “chybějících prostředků” na příkladu německého trhu skrze model dynamického programování. Následně simuluje implementaci tří opatření (kapacitních plateb, strategické rezervy a kapacitní aukce) za účelem zjištění, jaké opatření je proti zmíněné problematice účinné. Kapacitní aukce se zdají být nejefektivnější, neboť samotnou cenu za kapacitu zde určují v aukci účastníci trhu dynamicky. Práce dále podporuje vytvoření mechanismu pro zvýšení elasticity poptávky po elektřině, neboť je zde očekávána výrazná úspora nákladů.

Contents

Acronyms

CRM Capacity remuneration mechanism

CCGT Combined Cycle Gas Turbine

EEX European Energy Exchange

EUA European Union Allowances

EUR Euro

GW Gigawatts

GWh Gigawatt hours

MW Megawatts

MWh Megawatt hours

OOM Out-of-market (interventions)

PJM Pennsylvania-New Jersey-Maryland

RES Renewable sources of energy

SR Strategic Reserve

TSO Transmission system operator

VOLL Value of lost load

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Master Thesis Proposal

Author:	Bc. Ladislav Sobotka
Supervisor:	Mgr. Ondřej Strecker
Defense Planned:	June 2013

Proposed Topic:

Capacity remuneration mechanisms and the optimal electricity market design

Topic Characteristics:

EU electricity markets are facing fundamental challenges as a result of the EU goal to increase the share of the renewable energy sources. This policy results in less operating hours for conventional plants which negatively influences their profitability. Thus it puts the stability of the whole grid at risk in long-term, because the conventional plants are crucial to offset the variability of renewables and maintain stability of the grid. The electricity market design, however, allows for several measures to ensure sufficient generation capacity in long term.

The thesis focuses on the hypothesis whether there is currently a "missing money" effect on the German energy market. The hypothesis is tested by dynamic programming and with the non-convexity of the supply is dealt by the Semi-Lagrangean approach. Secondly, as capacity remuneration mechanisms (CRM) might be a solution, two types of them (strategic reserve and capacity payments) are implemented. Such analysis should quantify the benefits of the potential CRM implementation and yield also some EU energy policy recommendations.

Hypotheses:

1. There is a significant "missing money" effect on the particular electricity market
2. Capacity remuneration mechanisms (CRMs) are a viable solution to ensure sufficient generating capacity in long term.
3. Capacity payments are the optimal CRM model with the highest effectiveness in terms of the current EU market.

Methodology:

The first part of the thesis synthesizes the recent micro approaches towards capacity remuneration mechanisms under various conditions. As there are more approaches for the capacity market modelling, before deriving the conclusions a meta-analysis will be applied to weight all the relevant pros and cons paying a special focus on the underlying conditions the papers worked with.

In the thesis, the "missing money" effect is simulated by the dynamic programming with the simplified panel of sources that proportionally corresponds to the power market of one of the Member States. With the non-convexity of the supply is dealt by the Semi-Lagrangean approach.

Subsequently, two types of CRM (strategic reserve and capacity payments) are implemented.
The microeconomic reasoning of the situation when market does and does not provide adequate incentives to stimulate the proper quality of generating capacity will be demonstrated.

Outline:

1. Current EU electricity market analysis
2. Capacity remuneration mechanisms
    a. Effectiveness of the different CRM models
    b. Applicability for the EU market
3. Electricity market modelling
    a. Model and assumptions
    b. CRM implementation
    c. Results and their discussion
4. Findings and conclusions

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Author **Supervisor**

1 Introduction

The goal of the European Union to increase the share of the renewable energy sources (currently set as 20 percent of renewables until the year 2020) constitutes a fundamental challenge for the European electricity markets. The vast investments into the renewable sources of energy and the practically zero marginal costs of renewable result in less operating hours for conventional plants which negatively influences their profitability. This setting thus puts the stability of the whole grid at risk in long-term, because the conventional plants are crucial to offset the variability of renewables and maintain stability of the grid. The electricity market design however allows for several measures to ensure sufficient generation capacity in long term.

The thesis has thus two objectives to fullfil. Firstly, to test the hypothesis whether there is currently a “missing money” problem meaning that the conventional electricity generation is not profitable in long-term which constitutes a significant risk for the stability of the grid. The hypothesis is tested by a dynamic programming model and with the non-convexity of the supply is dealt by the Semi-Lagrangean approach. Secondly, as capacity remuneration mechanisms (CRM) might be a solution, three types of them (capacity payments, strategic reserve and capacity auction) are implemented into the model.

The thesis is structured as follows: Chapter 1 summarizes current situation at the European electricity markets and identifies potential threats in the near future. Chapter 2 analyses the capacity remuneration mechanisms including their efficiency and applicability. Chapter 3 is devoted to the electricity markets modelling and this chapter also summarizes the results and discusses the potential to derive relevant recommendations for the European energy policy. Chapter 4 summarizes the findings.

1.1 Current trends at the EU electricity markets

European Union has been striving for cleaner, more climate-friendly and non-exploitable sources of energy by supporting the renewable energy sources. One of the targets of the last climate and energy package set for 2020 is to raise the share of the EU energy consumption produced from renewable energy sources to 20 percent.

However, even the current share of renewables on the final consumption is equal to the 12,5%[1] (2010) and as the increase of renewable energy sources (RES) is more costly e.g. in transportation, it is likely that the final share of the RES in electricity generation will be substantially higher than 20 percent in 2020 (some estimates mention 35% in 2020). Such a high share significantly influences the energy markets and the discrepancies are predicted to grow further in the following years. To make the analysis more specific, the thesis focuses only on the electricity markets and the electricity generation, even though the European regulation challanges significantly also other energy sectors as domestic heating or transportation.

The first impact is surely the higher price of electricity. Considering the case of the Czech Republic, the share of the renewable electricity within the price is predicted to reach 15.8 % in 2013, but a part of the costs is also hidden within the systematic services (covered by ČEPS in CR) and electricity transfers (together 6.9% of the price). The Czech case can further illustrate the invisibility of the total costs for the renewable energy as the Czech government further subsidizes the renewables by 11.7 billion CZK annually.

In the long-term, the second important aspect is the change within the shares of the various sources of energy. Specifically, the renewable energy sources are characterized by practically zero marginal costs (as the need for fuel is neglectable) which means they are the cheapest to run once installed. As the installed capacity of the renewables is increasing, the conventional plants with higher marginal costs are forced both not to be producing in the growing fraction of the time and to play mainly the role of the back-up for the renewable sources.

A significant part of transition has already happened in Spain, where the annual time of the conventional plants – coal plants and the combined cycle gas

[1] Štruc, 2012

turbines (CCGT) – in operation has already dropped from an average of 6000 hours a year to 2500 hours (from the total of 8760 hours) meaning a drop from the 68 % to 28 % of the time in operation.

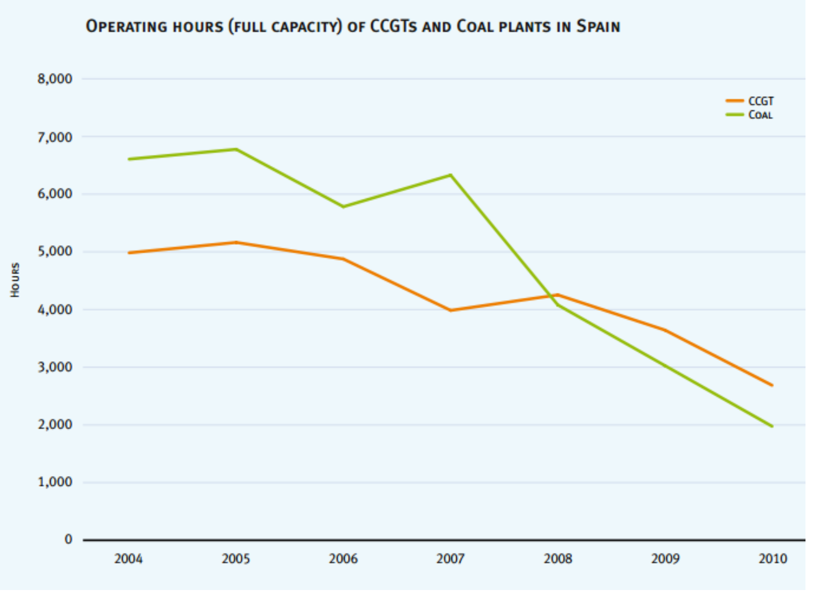


Figure1.1: Operating hours (full capacity) of CCGTs and Coal plants in Spain

Source: Cailliau M. et al. (2007), p. 10

Other important process within the EU power markets liberalization is the **market coupling.** By definition, market coupling consists in the implicit auctioning on two or more power exchanges. The border capacities are no more sold separately in the auctions but they are allocated directly to the exchanges. If the transborder capacities are sufficient, this process leads to the single clearing price in the whole coupled area. When the border capacities are insufficient (e.g. only for a few certain hours a year), the supplies and demands are cleared at the individual exchanges at the different prices.

Such a market integration has three main advantages (Pellini, 2012). Firstly, it is the economic efficiency as the demand is met by a wider range of supply and the probability of utilizing the producers with the lowest marginal costs is higher. Thus, the power market integration can be observable at the size of the spreads between countries which have been diminishing. Secondly, increase in cross-border trading weakens the market concentration and reduces the market power of the local dominant players. Lastly, market coupling secures the supply and reduces the reserve capacities as the grids are capable of mutual back-up.

As the French, Belgian and Dutch electricity markets coupled already in 2006 and Germany joined in 2010, the overall benefits might be relatively hard to quantify as there is a lack of similar economies to compare to. However, an analysis (Pellini, 2006) simulating replacement of the current explicit auction mechanism by market coupling in Italy identifies a welfare gains totalling (totaling = American spelling, totalling = spelling outside the U.S.) hundreds million euros per year depending on the exact scenario definition.

The high volatility of the RES production implies also a higher volatility of the spot price but it seems that the higher spot prices (in times when conventional plants are needed) are still not sufficient to compensate the operators of the conventional plants for less time in operation. This leads to decreasing profit margins on conventional plants and it might decrease the economic incentive to run, maintain or invest into conventional plants in long-term.

While the conventional plants are currently a crucial element helping to deal with the production volatility of the renewables, the lack of sufficient investment into conventional capacities might pose a risk for the stability of the grid.

Even though blackouts have not been very common events in the developer countries, they represent serious and quantifiable economic losses together with endangering the human health a lives. For example, the American-Canadian blackout in 2003 caused a net loss USD 6 billion and a net loss of 18.9 million work hours.

2 EU electricity markets

2.1 Power markets

As EU strives to liberalize the European power market and reach its goal of the single electricity market by 2014, the electricity market desings have been steadily converging. To be able to simulate the various market desings, a deeper understanding of the individual power markets in needed. Generally, the five types of the power markets are similar (division from Morthost et. al, 2010):

1) **OTC (over the counter) trading or bilateral trading**

   The trades are done bilaterally between the companies without any exchange. The quantities and prices are not public

2) **The day-ahead market or spot market**

   At the spot market, the bidding closes at noon for the deliveries from midnight for the following 24 hours. The trades are done via exchange and the prices and the volume are public.

3) **The intraday market**

   The intraday market is a platform where participants of the day-ahead market can trade until the given hour starts. The trades are done via exchange and the prices and the volume are public.

4) **The regulating power market**

   The regulating power market serves for regulation of the imbalances related to day-ahead planned operation. Here, the transmission system operators (TSOs) constitute the demand side of the market and the supply side constists of the electricity producers and consumers.

5) **The balancing market**

   Together with the regulating market, balancing market is used to help the TSOs to keep balance between total consumption and total production of power in real time. Technically, the TSO settles imbalances on the supply side while participants on the regulating and balancing markets are price takers.

2.2 The merit order and the merit order effect

Compared to other commodities, the pricing of the electricity has always been relatively difficult. Historically, electricity generation sector has grown up as a natural monopoly. This term describes the case when the costs of the technology are minimized if the production is concentrated within a single firm. This seems quite reasonable when one imagines the costs of doubling the distribution wires or pipes. Under such a monopolistic structure, the industry has vertically integrated and usually the cost-of-service model was applied for pricing (Hertzmark, 2012).

However, it is mainly the technical nature of electricity and our disability to store it economically which makes electricity pricing difficult. Location and time then play a significant role and make electricity heterogenous goods.

In the perfectly competitive markets, firms determine their production according to their marginal costs and the price set by demand. In optimum conditions, marginal costs of the last producer in operation (so called marginal producer) equal the market price. Producers with equal and lower marginal costs supply the production, while these with higher marginal costs stay off the market.

To make the situation transparent, it is useful to rank the individual producers according to their marginal costs in the ascending order which is called the merit order. As already briefly mentioned, the renewables have generally very low marginal costs and thus they are employed in the first place. The employment of the traditional power generators with higher marginal costs then depends on the actual demands and on the volatile supply of the renewables.

The merit order effect stands for the price shifting mechanism, when availability of the producers with the lower marginal costs shifts the rest of the marginal cost curve right which decreases the prices.

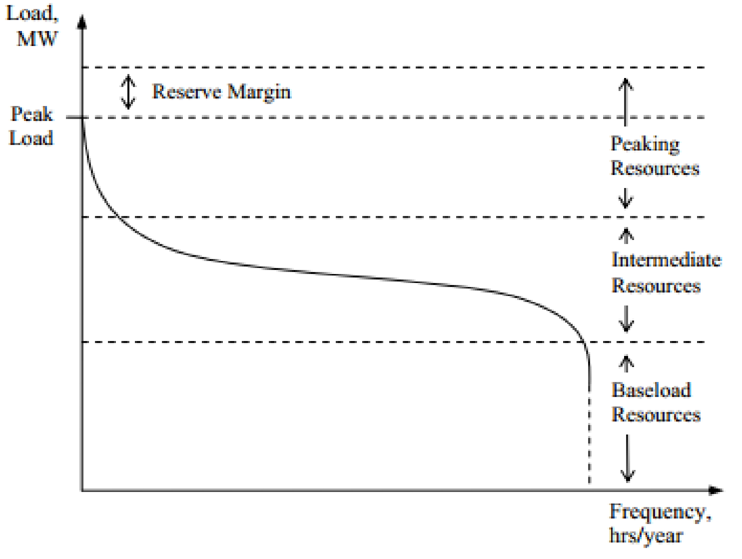


Figure 2.2: The merit order shift in prices

Source: Cailliau M. et al. (2007), p. 10

Every increase in capacities of the renewable sources of energy shifts the current producers with non-neglectable marginal costs visually further right which decreases the total time the producers will be in operation. Recent increase in RES has flattered the marginal cost curve and decreased the prices of electricity. In terms of the production during the year for the conventional producers, the whole curve shifts downwards as the conventional producers operate less.

The empirical estimates of the merit order effect have been the aim of several scientific studies. During the last decade, the estimates seemed to vary between 3 and 17 euro/MWh. To pick a concrete study, Sensfuss (2007) finds a 7.83 euro/MWh decrease in price on the spot market in 2006, which in total translates into 5 billion euro in 2006.

	Sensfuss	Sensfuss	Sensfuss	Bode, Groscurth	Neubarth et. al	Wiegt, Hannes	Munksgaard
Time	2004	2005	2006	Model period	2004-2005	2008	2008
Approach	PowerACE	PowerACE	PowerACE	Simple model	Statistical approach	Optimalization model	Statistical approach
Price effect (Euro/MWh)	2.5	4.25	7.83	3.17	6.08	10.5*	4.1*

Table 2.2: Comparison of the results for merit-order effect

An economic value in the form of reduction of wholesale electricity prices was identified also by a very recent Australian study (McConnel et al., 2013) where researchers strived to find also a break-even point for installation of the new capacities. At this point, an increase in the feed-in-tariff caused by newly installed 2 GW of photovoltaic capacities is fully offset by decrease in the wholesale price caused by merit-order effect. However, such simulations are very realistic for the following year of operation but tend to neglect the long-term development when decrease in the revenues of the peak producers endangers the grid stability as the RES still require occasional backup.

2.3 The market value of the renewables:

Most of the despatchable (non-fluctuating, independent of weather) renewable energy sources have already reached its potential (as hydro) or their growth is limited by sustainability concerns (as biomass). Thus the growth in the renewables is expected to come mainly from the non-dispatchable wind and solar.

However, the current infrastructure lacks enough transmission and storage capacities to accommodate the inherent volatility of the renewable energy produced in current volumes. This, in fact, decreases the market value of the renewable energy in three aspects.

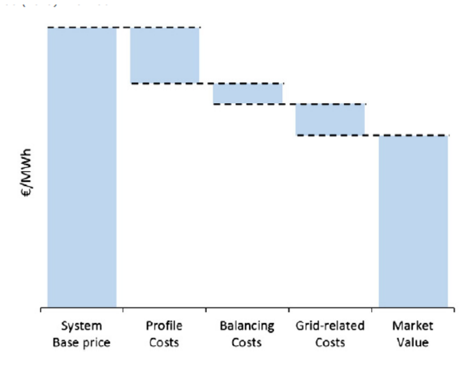


Figure 2.3: Illustration of the renewable energy sources market value

Source: Hirth, 2013

Firstly, the variability costs generally describe the drop in price when a large amount of renewables starts to produce. This is also called the merit-order effect. As explained in detail above, when a large amount of renewables with negligible marginal costs enters the market, some cheaper source becomes now the marginal one which sets the price. On the contrary, the price of the solar can be even above the market with small capacities (constituting an extra benefit of renewables and not costs) as it is generated mainly when the demand is high. For example in 2011, the solar power was sold on average by 10 percent higher than the base price (Hirth, 2013).

Secondly, as the schedule for the power plants is set a day before delivery based on the weather forecast, the output adjustments that have to be balanced on the intraday market cause extra costs that are to be distracted to reveal the market value. Thirdly and especially for the wind power, the generation sites are located far from the consumption which increases the transmission costs and there might be a transmission constraint in large production volumes.

Concerning the quantification of the variability costs, Hirth (2013) estimates the market value of the solar at 50 % to 80 % of the base price while having 15 % of the market share. For wind, similar price is reached at the 30 % of the market share. This implies a loss of about a third of the value.

2.4 Case study: German electricity price

Subsidizing renewables via feed-in tariffs leads to the changes in the structure of the price. While the power itself (traded at the energy exchange) is becoming cheaper due to the merit-order effect, the producers of the renewables are paid extra through the feed-in tarrifs.

Obviously, the largest share in the retail price still consists in wholesale power (8,13 cents), followed by distribution costs (6,54 cents) and renewable surcharges (5,28 cents). The continual boom in the construction of renewable capacities proportionally increases also the corresponding costs which have risen by 47 percent in 2013.

This design creates an interesting situation in Germany, where the government decided to exempt the energy-intensive industry from the renewable surcharges to preserve their competitivness.[2] As a result, the German industry is buying a cheaper power now thanks to the merit-order effect, while the households are subsidizing companies by paying the renewable surcharges alone. In terms of numbers, the

[2] Even though the argument is rational in general, the expanded list of companies includes also companies whose production is relatively hard to substitute by a foreign non-green competition such as the municipal transport services or e.g. the Stuttgart Airport

German retail electricity price rose by 7 percent in 2012 because of the renewables, while the industrial prices dropped by 18 percent. However, the whole drop should not be assigned to the renewables automatically (as some editors do[3]) as there is a whole bunch of other factors whose effects would have to be quantified.

Outlook

Even though the predictions are always hard to make and especially when the environment depends on the political decisions. From the point of the analysis, the crucial question is the development of the volatile RES capacities that are depicted on the following graph. The highest increases is expected at solar with almost 30 GW in only 4 years.

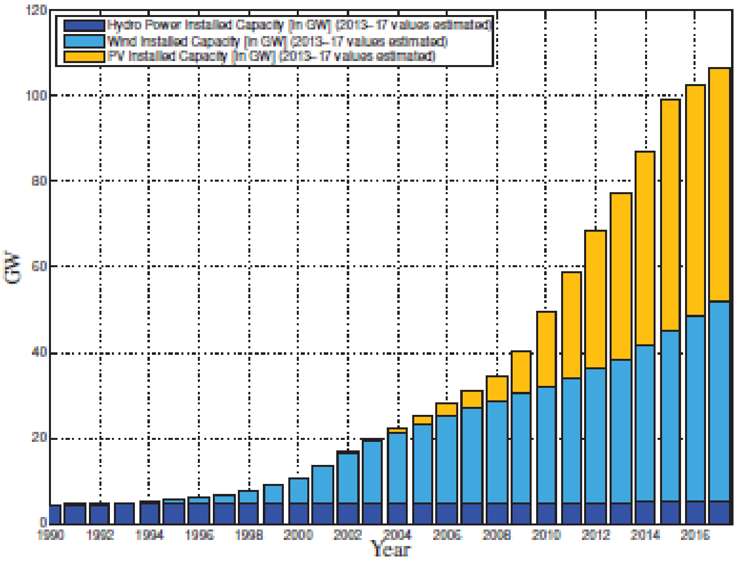


Figure 2.4.2: The expected evolution of the wind and PV installations in Germany

Source: noteEcofys 2012

[3] Renewables international (2012), Renewables raise German retail power rate by 7 percent but lower industry prices by 18 percent.

3 Optimal pricing design

3.1 Pricing mechanisms

The are basically three main pricing mechanisms for electricity markets, the uniform marginal pricing, the zonal pricing and the nodal or also called locational marginal pricing (LMP). It is possible to theoretically prove that the most efficient pricing is the LMP one, however, the biggest drawback in terms of the practical application is the large number of prices which might be confusing and transparency lacking.

3.3.1. Uniform pricing (current situation in Germany)

Under uniform pricing, the whole market clears at one price assuming an unrestricted network (so called copper plate). If there is no congestion in the grid, the uniform pricing works efficiently. However, in the congestion case the uniform pricing is unable to allocate energy optimally. To deal with congestion, uniform pricing includes uplift payments that cover the transmission expenses however these payments do not send the adequate market signal to ensure optimal transmission capacities.

To cover the congestion costs, the electricity pricing design in Germany charges customers for network access (fixed charge) and with variable demand charge. The network access fee covers renting a particular band used for energy delivery and includes costs induced by losses, ancillary services (as reactive support, black start capability etc.), voltage transformation and use of lower voltage grid. Apart from Germany, there are many countries using uniform pricing, in Europe, for example, Sweden (since 1996) and Finnland (1998) (Dietrich et al., 2007).

3.3.2. Zonal pricing

Under the zonal pricing, the grid is split into several zones with different congestion costs. If the demand exceeds the available transmission capacities, the congestion price rises and vice versa. Furthermore, the range of the zones can be either fix or floating, while the latter case allows for even a single price on the whole market if there is no congestion in the grid. So for the given hours without congestion, the design simplifies itself into the unified pricing design.

The main criticism of the zonal pricing covers its complicated structure, more administrative rules and potential for market power abuse. In Europe, zonal pricing is currently used in Norway (since 1991) and Denmark (since 2000).

3.3.3 Nodal pricing

Under the nodal pricing, the prices clear at nodes which are physical locations on the transmission grid. The price then singals the value of the electricity with regard to the location by taking into account the congestions and losses. The differences in the prices between nodes can be interpreted as the costs of the transmission.

The optimal dispatch within the whole system then reflects the conditions in the grid and sends the adequate allocation signals. The nodal pricing is used in Great Britain.

According to Dietrich et al. (2007), the nodal pricing is economically superior over uniform pricing with an increase in welfare around 0.9% and similar increase in welfare is the wind production in Germany is further extended by 8 GW. Identical conclusion is derived by Leuthold F., Weight H. and Hirschhausen Ch. (2007) with suggestion to implement a dynamic version of the nodal pricing that can effectively incentivize transmission owners toward optimal network extensions. The realized annual benefits seem to be lower or equal to the implementation costs as observed on the PJM and ERCOT (Texas) case (Neuhoff, 2011).

3.3.4 Comparison of pricing mechanisms

A study comparing different pricing mechanism was done with a focus on the implementation of the additional 9 GW of wind power (to existing capacities of 27 GW) to the German electricity market in 2015 by Weight et al. (2010). According to the results provided by the model ELMOD, the first-best option is to invest in construction of the three new high-voltage direct current (HVDC) transmission lines[4]

[4] Estimated cost of about 2.5 billion EUR

that would connect the North Sea wind facilities with the three inland high-demand centers.

To illustrate the simulation, all three potential scenarios generate similar clearing prices. Compared to the single price generated by uniform pricing, the zonal pricing makes the prices in the south slightly more expensive compared to wind-fueled north. Under nodal pricing, the price significantly varies at each node as for example a price increase of about 10 percent can be seen in the south.

The superior mechanism in terms of the welfare is the nodal pricing surpassing the zonal pricing and the uniform pricing by 30 million and 50 million EUR/year respectively. However, considering the total welfare of 188.10 billion EUR, the change represents a relatively small improvement by 0.016% and 0.027%. The zonal pricing has the lowest losses and the amount of unused wind is decreased by 40 GWh/year (15.4%) compared to uniform pricing. However, as it might be difficult to communicate customers the electricity price differences, an option to average the nodal price over a larger region for retail customers is often utilized, even though it limits the price responsiveness.

Under the condition of the insufficient grid extension, some form of the active wind facility management has to be applied. A very high wind input generally forces operators to take additional measures such as line switching or wind curtailment.

If the network constraints are neglected, guarantion of the priority wind input is often reached only by some other transactions that are out of the market such as the cost-based redispatching.

Similar conclusions are derived by Brown (2009) in the case of Ontario, who prefers nodal pricing under the conditions of the grid limited by transmission contraints and a large share of the volatile RES. Some authors as e.g. Joskow (2007) state that there are costs of not adoption of the locational pricing.

3.2 The grid and the capacities

Even though the installed capacities of the renewables might be synchronized geographically and by the kind so that the total output would be relatively balanced (as the proponents say, there is always some wind within an area like Europe), the weakest point of the system became the electricity grid. Within the area of the Central Europe, the grid was surely not conceived for the now intended electricity transfers and there were no comparable investments into the grid in the last two decades.

At this place, the need for the international solution of the issue must be highlighted because the electricity is traded internationally at the liberalized market while these trades employ the nationally operated transfer grids. This results into significant externalities for some of the involved parties.

A relevant illustration might be the recent development at the German borders, because the Czech, Polish, Slovak and Hungarian grid operators are trying to open a discussion about either some form of internalization of the externalities caused by a massive trading within Germany or by cancelling the electricity trading zone between Germany and Austria. As the traded volumes exceed the available transmission capacities even twofold (two times = dvakrát, twofold = dvojnásobně) within this trading zone, the electricity is then physically transferred over neighbouring countries. This reduces the available capacities for the other countries, increases the risk of the blackout and also raises the other costs as maintenance, further investments or the physical electricity losses incurred during transfers that are not accounted for under the current regime.

3.3 The “missing money” problem and its causes

The current pricing designs for electricity have been well explored and in short term they perform quite efficiently. This regards the main aspects as setting price at the voluntary transparent market for both energy and ancillary services, locational pricing that reflects the marginal costs of congestion and transmission losses and the responsiveness of the demand to the current energy scarcity via price (Joskow, 2006).

However, in the long term both theoretical and empirical findings suggest that such a market design is not sustainable because the peak operators do not fully cover their costs which is disincetivizing the investors for further investment into peak capacities. Such a situation is called the **“missing money” problem** which describes the problem of the infrequent operation of the peak (sometimes even mainly backup) and expensive generation capacities that strive to cover their capital costs during relatively scarce periods when put in operation.

The base scenario for market design considerations is called **energy only market** where it is the price alone that clears the market and determines the reserve margin. Further, there are no out-of-market (OOM) interventions from the system operator. When there are no more unutilized capacities for power generation, the price rises until the demand cuts itself voluntarily.

In theory (under the assumption of the well-functioning spot market with no price caps), the spot price would get high enough to cover the cost of all the generators. Such a price would let them earn the scarcity rent and ensure sufficient supply in the long-term. Interestingly, even though the shares of the fix and variable costs are different among producers practically in all sectors, the missing money problem seems to be unique for electricity markets only.

Thus, the crucial question is why the spot market does not provide peak generators a sufficient scarcity rent through the higher prices during critical hours. The literature reveals several potential causes of this missing money problem.

First of the causes behind the “missing money” effect is the **non-linearity of the cost function.** While on the other markets the cost function is relatively smooth and linear, on the energy markets there the supply reflects the fuel costs function which is much more non-linear a non-smooth. The illustration of such fuel function can be provided by the following example:

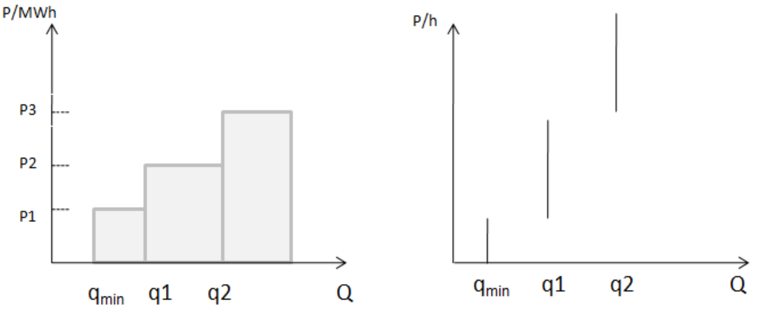


Figure3.3: Non-linearity and non-smoothness of the supply

Source: own graph

The second bias of the spot price is the fact that the **renewable energy sources dominate the spot market** relatively to their real production share. According to Hildmann et al. (2013), this is caused by baseload production traded largely bilaterally out of the spot market. Even though the subsidized RES produce currently less than 20 percent of the total demand, 50 percent of the volume on the spot market are with RES. Hidlmann et al. thus recommends a higher proportion of the current OTC trades to be traded on the spot market if the current energy-only market design is to be kept.

The third cause is the **disability to store electricity economically** which significantly reduces the possibility of shifting production in time.

Another cause is the **limited resposiveness of the demand** function (both at the day-ahead and the real-time markets) which would ease to clear the market during peaks. Only a small fraction of consumers monitor and respond to the price these days. Even though there are measures by means of which system operator can respond on behalf of retail consumers (via “priority rationing contracts”) during the several critical hours a year and do so in exchange for the lower price, technically are these measures still complicated as the operator usually controls the area by larger zones with different consumers.

Together with increasing the price elasticity of demands it is also important to let the price express the scarcity of the goods **without intervention**. The current practice of some system operators to roll blackouts when they expect some problematic situation does not allow the market price to increase enough to reflect the market setting. Surely, there are also other interventions prior to the blackout as 5 percent reduction in voltage, whose social costs are hard to estimate (Joskow, 2007). Similarly, the **price caps** imposed by regulator do not let the price rise sufficiently high. Rationally, if the producer with the highest marginal costs operates only a few hours during the whole year, the revenue from these hours has to cover all the costs. On the other hand, the price caps are introduced to prevent from abusing market power and as the markets are not fully competitive, the measures against the market power abuse have to be considered. Importantly, the price caps will not be the only cause of the missing money problem as there are cases when prices did not reach the price caps even during the most critical hours (Joskow, 2007) and probably some out-of-market measures of the system operator treating the situation are to be analyzed more deeply.

Last but not least, the **unstable regulatory framework** deters investors as their profits are dependent on the new potential policies and regulation.

Surely, there are extra costs associated with the missing money problem. While in short-term, it is the higher risk of blackout, in long term, the investors become reluctant to enter the electricity sector as the low prices do not suffice to cover the capital costs.

There are several studies illustrating the missing money problem as Joskow (2007) or Madrigal (2000). Both of them define some simplified electricity supply and assume different marginal costs. After a few runs, the payoffs of the individual generators show that the prices based on the generators´marginal costs do not cover the capital costs of the most expensive (and the least operated) plant, so that the missing money problem is present.

Theoretically, in order to design a simplified model of the market with no missing money problem, several underlying assumptions have to be met. Most importantly, the wholesale price has to follow marginal costs and be allowed to rise freely to reach the demand during peaks without any caps. Other conditions are efficient dispatching and no rolling blackouts for price sensitive consumers (Joskow, 2007).

4 Capacity remuneration mechanisms

The missing money problem is a significant obstacle when relying on the invisible hand of the market that should ensure an adequate generation capacity in the long-term. According to the Hummel (2013), entsuring furure generation adequacy via capacity payments for the producers burning hard coal and gas are inevitable by 2017 when the capacity market in German could annually reach about 1 billion euros. Nevertheless, the price of the forward contracts is expected to fall further due to the capacity payments.

In fact, there are two main ways to how to deal with this problem and secure sufficient revenues for all power generators.

4.1. Improvement in the spot market functioning

4.1.1. Demand flexibility

The first set of measures targets directly the causes identified in the previous chapter. One potential measure to improve the market functioning is an increase in the elasticity of demand realized by smart-meters and dynamic pricing for the final consumer. The expected shifts of the consumption from critical moments toward the less scarce ones could significantly slash the costs of the current capacities.

The price elasticity is very convenient as the demand for the peak generators gradually decreases when the prices reach the trigger level P1.

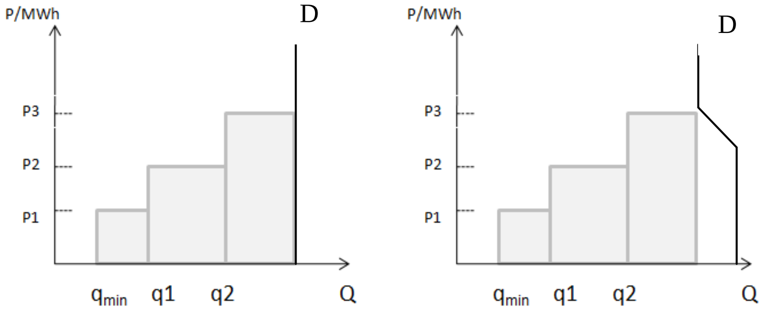


Figure 4.1.1: Market without and with the demand flexibility scheme

Importantly, the electricity demand has historically been considered as inelastic and the efforts to limit the consumption during the peak hours have been relatively scarce. Thus, there is plenty of the low-hanging fruit to pick with minimal costs and the current marginal costs for a decrease in the electricity consumption by 1 MW are often cheaper than the construction of the additional capacities. Consumption adjustments have been a part of the PJM market design and the current experience confirms their price advantage over new capacities.

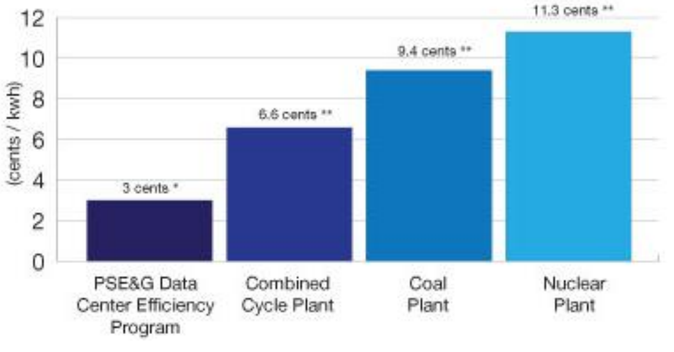


Figure 4.1.2: Costs of the demand adjustments vs. the new capacities

Source: Nicolosi M., 2012

For the PJM, the efficiency program can adjust the demand in the way a 1 MW of the extra capacity is saved. This is done at the cost of about 3 USD cents per kWh, while new capacities range from 6.6 to about 11.3 USD cents per kWh on average.

There have been a few attempts to quantify the damand flexibility for the German power market. Even though the approaches and assumptions vary, we can conclude there is a demand flexibility adjustment within the range of 8 to 16 GW as seen on the following graph:

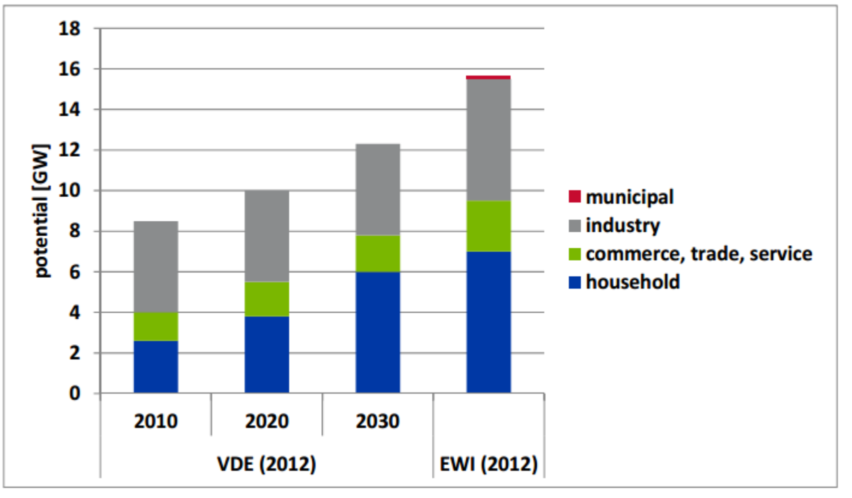


Figure 4.1.3: Potential of the demand flexibility

Source:Ecofys (2012)

The EWI estimates are more optimistic with the current potential of almost 16 GW, the VDE current estimate is only a 8 GW with an expected growth in the future. Both studies identically assess the dominant potential for demand flexibility at households and industrial sites, while is potential for the flexibilizing the demand within the tertiary sector is limited. The scheme considers mainly the energy-intensive industries and basic home appliances.

Even though there might be a technological potential, the economics of the measures is the key determinant for the implementation. Even though there are no cost curves of the demand flexibility for the German market, a look on the PJM realized measures might be reveal the corresponding costs. According to the assessment done by Pfeiferberger et al (2011), the first 7 years of the PJM operation (2007 – 2017 currently traded) have increased its capacities by 28,400 MW, out of that 42% were demand side adjustments, 24% increased transborder trading and 17% newly build capacities. Please note that the increase is in fact in the form of liability as there currently traded capacity payments are for the year 2017. With regard to the current record peaks surpassing 160 GW, the demand flexibility might reach up to 7.5 percent in 2017.

Even though some critics might consider capacity increases backed by only a minor construction as suboptimal, the increased elasticity of the demand side should be evaluated positively as the marginal costs are at the beginning lower than actual construction.

4.1.2. Other spot market measures

Secondly, the streghtening of the transmission capacity both in local markets and with neighbouring markets should help to balance the lacks and surpluses in the capacity.

Next, the price caps implemented in various countries should be abolished or significantly increased as the large increases in price do reflect the low elasticities of both demand and supply. If some of the out-of-market (OOM) measure is applied by the system operator, the spot price has to be simultaneously sending the critical scarcity singal. Naturally, the progressive rise in price corresponds to the generators´ need for a strong stimulus to increase the supply.

Another interesting suggestion *(Cailliau, M., 2011)* is to incetivize the RES generators to participate in the market directly and not through the central operators. The shift of the responsibility for selling its volatile production towards the generators themselves should reduce the now occurring negative prices and other market distrortions. This option will be further explored within the following part of the thesis.

4.2. Implementation of the forward capacity market

Even though a precise implementation of the recommendations suggested for the spot market should be sufficient to solve the missing money problem, the expected length of the path towards the spot market with negligible frictions implies a solution combining improvements in the spot market with some of the capacity remuneration mechanisms. Surely, as the spot market efficiency might improve in time, the capacity payments might be only a temporary and transional mechanism.

4.3. Summary of the different CRM models

In principle, the capacity remuneration mechanisms (CRM) guarantee investors a small, but certain payment for the installed capacity. Such measures do both increase the installed capacities and slightly lower the supply curve, leading to the reduction of the volatility at the market. These are very valuable pros in the long-term as the proper incentives would lead to the higher generation capacity and consequently to the higher security of the system.

The main objection against this concept is that such a setting is a further regulatory intervention and it is the current market design with RES that is to be changed. Such regulation would then preserve the design for decades by disincentivizing alternative options, which in reality means a difficult switch back towards market driven demand or investments into energy storage.

Secondly, the European intergrating markets should have as similar designs as possible and the implementation of capacity remuneration should be carried out ideally within the whole market area. However, the default settings are very heterogenous among the countries and unification would require a vast amount of political capital.

Even though there are many features that are similar among the individual types of CRMs, the recent literature has been analyzing several key types of the capacity remuneration mechanisms *(as in Wieckowski, 2011 and Cailliau, 2011):*

1) **Capacity Auction**

    An example of the capacity auction is the North American reliability pricing model that is used in PJM area (Pennsylvania, Jersey and Maryland). Here, the target aggregate demand for the whole region is estimated 3 years in advance, an expected sufficient reserve margin is added and this whole capacity is bought via auction each May three years in advance of the future delivery. The reliability contracts are then further traded, however, delivery of the capacities is binding and breaching this commitment would lead to a significant penalty for the producer.

    On one side, trading in advance enables producers plan effectively as they can sell the capacities of the plants that have not been realized yet. Also, it keeps the risks for the producers (are?) the market risks and compared to other options, it diminishes the regulatory risks of the future changes in capacity prices that are arbitrarily set by the operator.

    Overall, the centralized auction squeezes the price and leads to a transparent and liquid pricing, however the volatility of the price is always partially confusing as a price signal for investments compared to the fixed pricing under other designs. Generally, the capacity auction is together with the strategic reserve the most considered design for the Germany or EU.

In terms of the prices paid, the PJM experience since 2007 shows that the prices have been steadily falling, the 2017 capacities have traded this year at a base price of 59.37 USD/MW-day. The last annual drop is assigned to the new gas-fired generation capacities and increased imports.

2) Strategic Reserve

Under the Strategic (or Peak Load) Reserve, the central operator is purchasing a capacity (e.g. several GWs) which can be used during the peak times, when the supply is unable to meet the demand. Such mechanism is used e.g. in Sweden and Finland, where it was introduced after the liberalization of the market in order to keep installed capacities of the more expensive oil plants. The application of the Strategic Reserve can be illustrated as following:

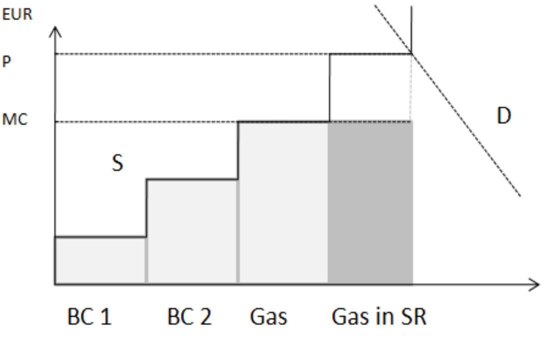


Figure 4.3.1: Application of the Strategic Reserve

Source: own graph

It is clear that after demand increases above common levels, the gas generation plant under the strategic reserve is activated. Even though its marginal price is stil MC, the clearing price in this market situation will be P. The two plants with the lowest marginal costs are brown coal (BC) plants.

3) Capacity payments

Under the capacity payments scheme, all generators are paid by a fee for providing a capacity. When meeting the criteria of a quick availability, the generators can be paid even when switched off as a backup. A specific setting allows the payments to drop to the zero in the situation when there is a sufficient capacity margin. However, there is a risk that the investments will be driven mainly by the capacity payments, which means a further distortion of the market.

In Spain, the scheme has the following desing using the Reserveindex that is defined as the net available capacity / peak demand. The remuneration of the generators is set to 28 euros/kW, but the payments decline linearly with an excess of the capacities.

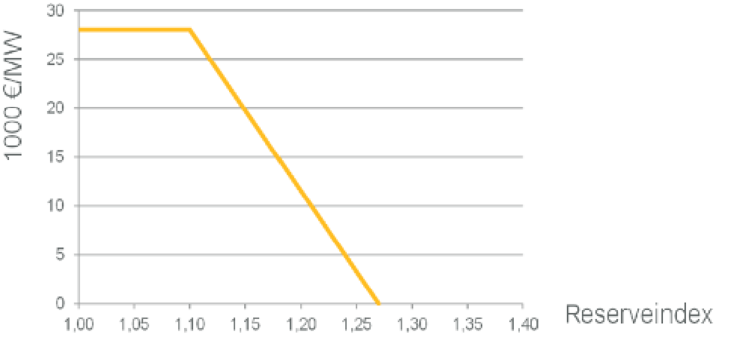


Figure 4.3.2: Size of the capacity payments in Spain

Source:EWI 2012

Such an amount of finances is already substantial as the 200 MW power plants can receive about 5.6 million euros/year.[5] On the other hand, the decreasing capacity payments down to the zero should guarantee there are not massive amounts of capacities built only to benefit from the capacity scheme.

4) Reliability option

The option component consists in the right to dispatch the capacity when the price reaches the strike price. This measure has been recommended by academia, but the practical use is so far limited, which can be perceived as a lack of good experience with this kind of measure. The second challenge is finding the optimal strike prices, as both too low and high prices have adverse consequences.

In terms of the definition, the strike price is set by the system operator and the electricity distributors buy these options in order to hedge against the peak prices above the strike price. The producers who are selling the options are obliged to pay the difference between the peak price and the strike price when the option is in the money. In the given hour with the demand d, clearing price P and the share of the producer´s capacity on the total market capacity s_i,

[5] As the 200 MW * 28 000 euros = 5.6 million euros

the electricity producer is obliged to realize a payment equal:

$$R_i = s_i * d * \max(0, P - K)$$

5) Capacity obligation

A similar system as the strategic reserve, but here the suppliers are to contract with generators, so the system in decentralized.

4.4. Existing and planned capacity mechanisms in Europe

After the liberalization of the electricity markets in the previous years, the question of the capacity remuneration is becoming increasingly topical. The first market to compensate regulators for capacity was Sweden in 1996 and it is predicted that most of the countries will employ some form of the capacity remuneration by 2017.

There are some electricity markets that have not publicly considered any capacity mechanisms so far (Benelux countries, a few East-european countries) and that seems to stay "energy-only" markets. This term describes markets with no capacity payments in the day-ahead and intraday markets, but with the possibility of the contracting a market reserve capacities (CREG, 2012).

A brief illustrative summary of the mechanisms in Europe can be as following:

Position	Country
Energy-only market	Netherlands, Belgium, Hungary, Norway
Partial CRM	Portugal, Spain, Lithuania
Proposal for CRM	Poland (2014), Germany, Italy (2017), France (2016), UK
Major CRM	Russia, Ireland, Greece
Regulated restrictions	Balkan countries, Ukraine

Table4.4: Capacity mechanisms in Europe

Source: Data from Regulatory Commission for Electricity and Gas, 2012

Even though the common trend is an implementation of some form of the capacity remuneration mechanisms, this trend must be viewed with caution. Firstly, there is no mechanism that would secure the supply with absolute certainty and secondly, each implementation of the capacity mechanism has to be regularly reviewed as there are usually numerous amendments in the setting as e.g. in US PJM or Spain (reduction of payments in 2012).

4.5. Risks

Surely, a profound change in the electricity design can lead to some undesired results. The highest uncertainty is in the optimal setting of the capacity parameters, as high support of the peak load might lead to the construction of the excess capacities that would subsequently lead to the lower payoffs for the peak generators. This is nevertheless only the case of the arbitrarily chosen support by the central regulator, capacity auctions find their optimal values through an auction.

Second uncertainty is the integration of the environments with substantial market power that endangers the efficiency of the capacity markets.

As Nicolosi (2012) suggests, there is also a chance of the technological lock-in effects and exclusion of the new technological options as the suppliers are subject to a prequalification process. Thus, a detailed feasibility study assessing these aspects and estimations of the costs and benefits is always recommended.

5. Methodology

5.1. State-of-the-art approaches of the electricity market modelling

Both researchers and stakeholders currently model markets for electricity by robust models covering the whole energy sector. Various recent studies covering the topic of capacity remuneration have employed or developed models such as model PowerAce (Genoese, 2012) or model DIMENSION (EWI, 2012).

The Genoese (2012) employs already existing agent-based model PowerACE for electricity markets in order to assess the impact of the capacity remuneration mechanisms on the both development of the installed capacities in the long-term and the electricity prices. He finds that he capacity payments incentivize the investors to build the capacities earlier in time and to build more capacities than in the default scenario.

The dynamic programming was applied by Khalfallah, 2009. Concerning his findings, the market-based mechanisms should be the most cost-efficient mechanism to secure the sufficient capacity generation in the long-term. Secondly, Khalfallah identifies a risk of extorting market power by the generators when the capacity payments are implemented. Last but not least, the analysis within different types of competition revealed that mainly the monopolistic competition leads to the higher payments from the final consumers and more capacities installed.

The findings for the German economy done by the robust model DIMENSTION (EWI, 2012) do assess the growing requirements on the current energy-only market at excessive…..(nechybí tady nějaké podst. jméno?) and suggests to apply one of the capacity mechanisms. Interestingly, the study finds the strategic reserve mechanism as inefficient. Secondly, the need for capacity mechanisms becomes urgent by the year 2020 for Germany in order to keep the security of the supply at the acceptable level.

However, when discussing the outputs delivered by these robust models, the micro-structure of the individual mechanisms often stays obscure. This might be the case of the missing money problem, as it is practically impossible to find any clear demonstration of several scenarios with different size of non-convexity of supply including corresponding payoffs for the power generations.

Not only the capacity remuneration mechanisms seem to be the only option, as Joskow (2007) identifies three main problems that might deincentivize the investors from investing into new capacities: i) the missing money problem when the capital costs are not fully covered by insufficiently high prices of electricity ii) the volatility of the prices and iii) the uncertainty of the regulatory process that sets the market conditions. Interestingly, Joskow states that an alternative to the capacity remuneration mechanisms to overcome these issues might be the implementation of the forward capacity market, that can jointly with the spot market secure the sufficient amount of generation capacities.

5.2. Data used

5.2.1. German power prices (EEX)

For the purpose of the analysis, a dataset containing German hourly power prices cleared at European Energy Exchange (EEX) for the year 2012 was purchased. As visible from the following chart, the prices developed steadily around the average baseload price 42.59 EUR/MWh. The average peak load (between 8:00 and 20:00 on workdays) traded at 48.27 EUR/MWh, while the off peak traded on average at 37.12 EUR/MWh.

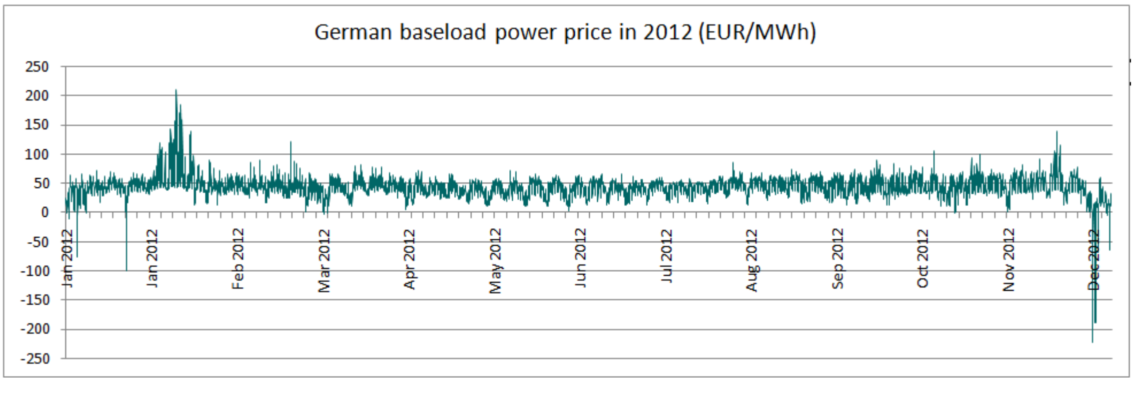


Figure 5.2.1.: German baseload power price in 2012 (EUR/MWh)

Source: EEX data

The price distribution can be characterized by sigma equal 18.6 EUR, however most prices concentrate within the range of 35 – 60 EUR. Moreover, there were 30 hours out of the total 8784 hours during the year 2012 with negative price for electricity.

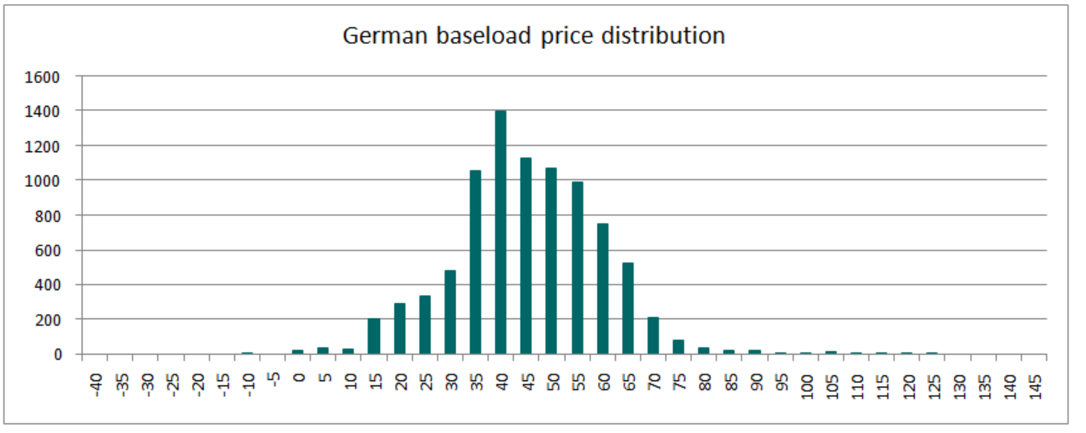


Figure 5.2.2.: German baseload price distribution

Source: EEX data

5.2.2. German power consumption (ENTSO-E)

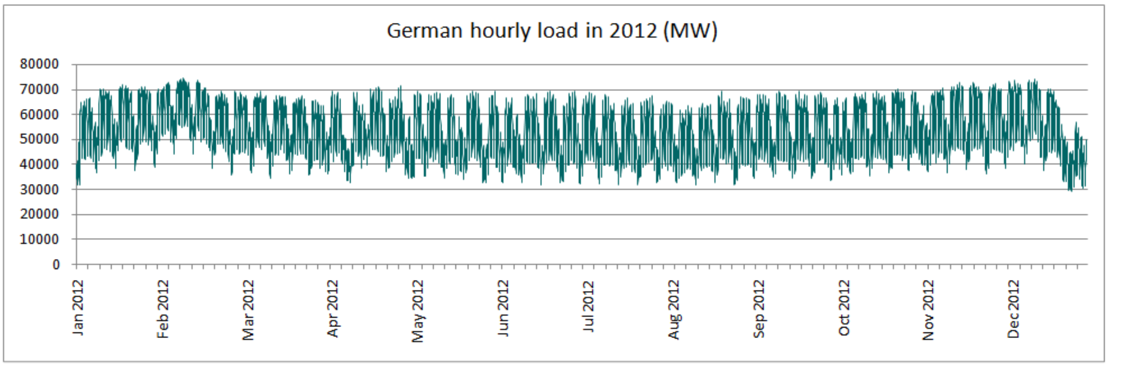


Figure 5.2.3.: German hourly load in 2012 (MW)

Source: ENTSO-E data

The hourly load data about the German power consumption during 2012 were provided by the ENTSO-E that is the European network of transmission system operators for electricity. There are several significant patterns consisting in higher prices during the day, on workdays and in the winter period which are observable on the following chart.

The average consumption during the year 2012 was 53458 MW and during 66.27 % of the time the consumption was between 1 sigma bound of 43.1 GW and 63.8 GW. There are two most common loads around 45000 MW (off-peak hours) and 65000 MW (peak hours). The detailed distribution is depicted on the following graph with x axes standing for consumption in MW and y axes depicting frequency (out of the 8784 hours during the year 2012).

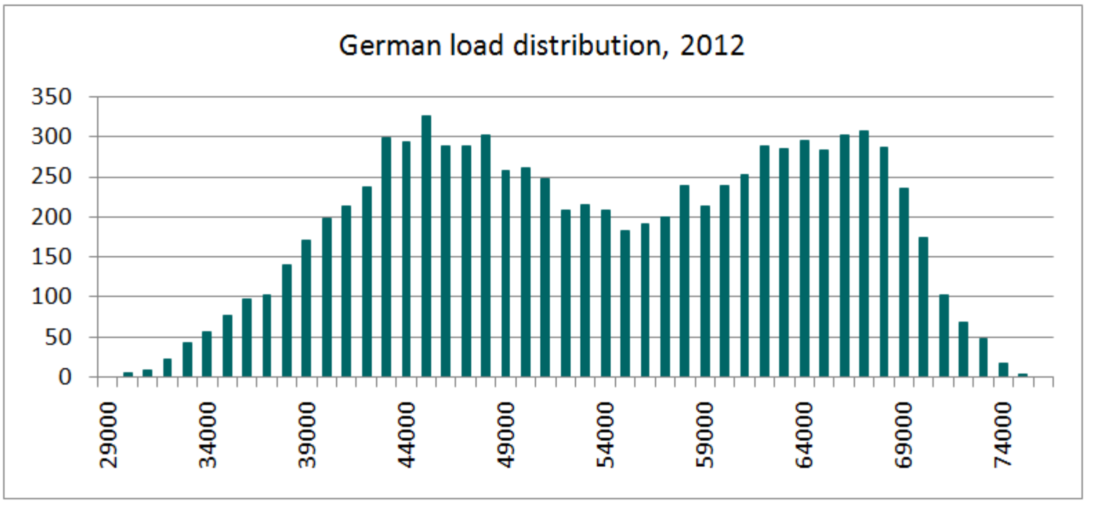


Figure 5.2.4.: German load distribution (MW)

Source: ENTSO-E data

5.2.3. German power mix (EEX transparency network)

The German transparency guidelines legally bind the four German transmission system operators to publish the data about the power production and consumption who publish them jointly via the EEX tranparency platform. The platform publishes the results for producers with output higher than 100 MW individually and offers thus a very detailed look on the German power mix, however the data are charged with a fee that is above the budget constraints of this thesis.

As an alternative solution, a day with the highest production from the conventional sources is identified by statistics provided by Burger, 2012. The highest production from the conventional sources was on 12th of December 2012 between 17:00 and 18:00, it equaled 66.5 GW. As 71 percent of the installed capacities with a net nominal output < 100 MW are wind and solar, the remaining 29 percent constitutes of 18.9 GW from the various sources, mainly gas.

Even though the net RES capacities installed are generally known, they usually do not operate fully at the same time. Thus a record RES production values of the year 2012 are taken into account in order to construct the German supply curve in 2012. The all-time high for solar reached 22.4 GW on 25th of May 2012 and the wind production generated the most 24.1 GW on 3rd of January 2012.

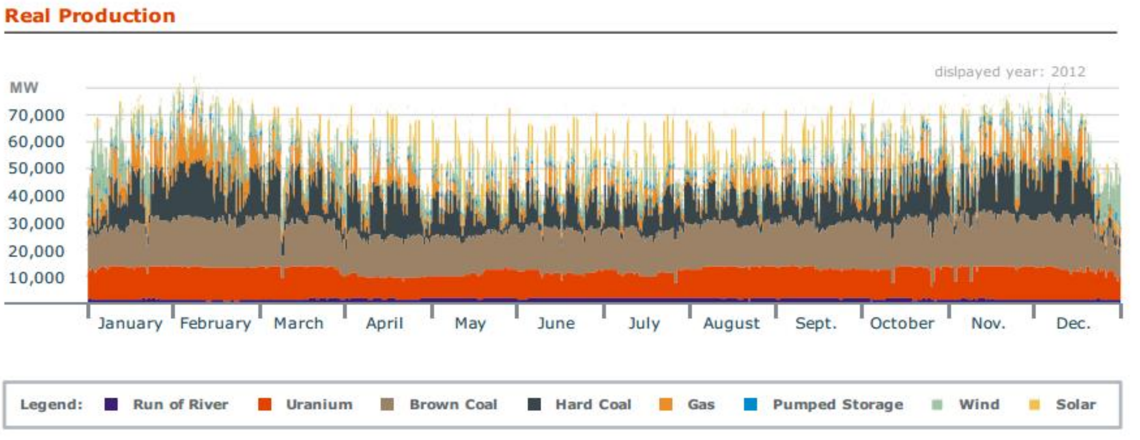


Figure 5.2.5.: German production during 2012

Source: Burger et. al

Nice representation of the German power mix is done by Burger, 2013 on the following graph. The defined power generation mix is stated in the next subchapter together with its marginal prices.

5.2.3. Marginal prices and fixed annual costs

The marginal prices of the individual energy sources have already been estimated by several authors. A small literature review offers the following comparison of the German (or generally Central European in V. Gilles case) marginal prices:

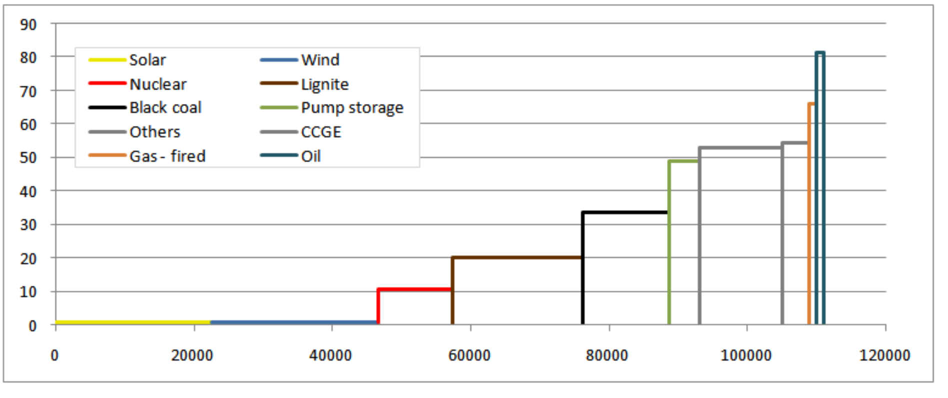
COSTS	Capacity	Margincal costs	Fixed costs
	GW	EUR/MWh	EUR/MW/day
Solar	22 400	0.0	201
Wind	24 100	0.0	186
Nuclear	12 077	10.8	291
Lignite	18 778	20.1	195
Black coal	12 472	31.2	181
Pump storage	1 467	49.0	275
Others	11 990	53.0	105
CCGT	3 820	54.5	105
Gas - fired	2 820	72.5	105
Gas - fired	1 000	76.0	105
Oil	1 070	95.3	105

Table 5.2.3: Marginal costs of the individual generators (EUR, 2012)

Source:own calculation

Importantly, all three studies set relatively similar prices. For the purpose of the analysis, the Gilts prices are used as he summarizes also the commodity prices and states other figures useful for backtesting as dirty spark spread and clean spark spread. To explain, the dirty spark spread is a theoretical gross margin of a gas-fired power plant calculated as the difference between electricity price and the fuel price adjusted for the heat rate. To calculate the clean spark spread, a value of the emission allowances needed for 1 MWh of electricity must be distracted (distracted znamená rozrušený, nemá tam být "extracted"? from the dirty spark spread. In August 2013 clean spark spread was traded at around minus 20 euros at the end of July 2013 and has been negative since February 2013. (tady jsem moc nepochopila, proč tam jsou dva časové údaje – August a at the end of July)

The constructed supply curve has thus the following structure:

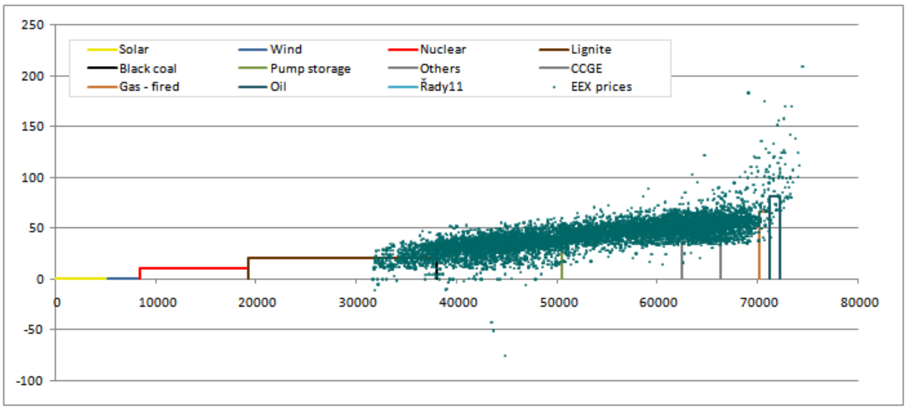


Figures 5.2.6: Marginal prices of the individual generators (CS, EUR/MWh, 2012)

Source: own calculation based on Gilt

Even though some authors model renewable energy sources as sources with zero (or more exactly negligible) marginal costs, some authors argue that even sun and wind power have positive marginal costs. The operation and maintenance costs review (Hildmann, 2013) suggests that the applicable marginal costs for wind generation is 26.85 EUR/MWh (as literature survey reveals the range of 15 to 27 EUR/MWh) and for PV generation 22.54 EUR (within the range 22 to 33 EUR/MWh). These positive costs and the zero marginal costs are modelled separately within two different scenarios. Obviously, the results will have no effect on the peak producers as the market clears on their marginal costs.

To validate the marginal cost curve, it should be compared with the prices from the energy exchange that were revealed through matching of the supply and demand via marginal pricing. Nevertheless, due to the unavailability of the renewable production hourly data, the renewables in the supply curve must be cut from their maximal capacities to the average hourly production. Based on the EEX transparency data, the 2012 annual production equaled 45.9 TWh for wind and 27.9 TWh for solar. A division by 8784 hours thus yields an average net production of 5225 MW and 3176 MW respectively. The electricity prices seem to confirm the electricity supply curve as it can be seen on the following graph.



Figures 5.2.7: Merit order and the whole electricity prices, EUR/MWh

Source: EEX 2012, own calculation based on Gilt

Pluging-in the (currently unavailable) hourly import-export data as well as the hourly renewable production would probably further remove some noise and reveal the supply curve more sharply. Nevertheless, the proportions of the merit order and the marginal prices seem to be correct.

To make the shares of renewables dynamic, the actual wind production is modelled as function of the spot price. As Niewenhout (2013) estimates the price decrease related to the shift from zero wind to the full capacity of 24.1 GW to 17.6 euros on the day-ahead market using the wind forecasts, a basic positive relation assuming a difference in production of wind by 1 GW from the average for the each 0.80 cents of the deviation from the average price is assumed. The average price means peak and off peak price separately, the whole prediction is subsequently shifted to reach the actual wind production.

5.3. Model and assumptions

5.3.1. Model assumptions

Initially, we assume a perfect competition at all electricity and capacity markets so there are no oligopolies or monopolies with the possibility of exerting a market power. The demand within the model is considered as price inelastic, final consumers do not play an active role which is true especially in the short run.

As the detailed hourly data availability is very limited, several simplifications had to be applied. Firstly, the German power market is modelled as an isolated unit without any imports and exports. This assumption biases the results and leads to an underestimation of the need for the capacity payments because the price at the isolated market is more volatile which is positive for the peak producers.

5.3.2. Benchmark scenario – energy only market

This kind of dynamic programming problem is in literature called Unit Commitment and Dispatch problem. The aim of the optimization problem is to find proper electricity generators in order to:

- Ensure the total supply meets the total demand
- While minimizing the total costs
- Respecting the individual constraints of the individual producers.

For the purposes of the model, let´s assume that there are (similarly as Araoz, 2011):

- *k* different technologies for electricity production
- *p* plants that are able to produce electricity
- then for each technology i (out of k), the total cost function is equal the sum of the fixed and variable costs:

$$C(q_i, z_i) = \sum_{i=1}^{k} \sum_{j=1}^{p} FC_i z_{i,j} + \sum_{i=1}^{k} \sum_{j=1}^{p} VC_i q_{i,j}$$

where $q_{i,j}$ denotes the production by the technology i from the generator j and $z_{i,j}$ denotes the dummy variable for given plant being in operation.

Then, we can state the following optimization problem:

$$Min \sum_{i=1}^{k} \sum_{j=1}^{p} FC_i z_{i,j} + \sum_{i=1}^{k} \sum_{j=1}^{p} VC_i q_{i,j}$$

s.t.

$$\sum_{i=1}^{k} \sum_{j=1}^{p_i} q_{i,j} = D$$

$$z_{i,j} \in (0,1)$$

The cleared price than determines the revenues of the individual producers, as we can define the producers profit in time t as the following:

$$Profit_{i,j} = R_{i,j} - C_{i,j}$$

as $R_{i,j} = q_{i,j} * P$

and $C_{i,j} = FC_i z_{i,j} + VC_i q_{i,j}$

where $R_{i,j}$ stands for revenues of the producer I Ci,j for the costs

In terms of the methodology specifics, there are generally two ways of modelling the electricity markets, each one at the either side of the Atlantic. The Vyve (2011) tries to combine these approaches within one methodology with following features:

For the typical US model, the combined approach includes:

- Welfare maximization
- Loss-making acceptance of orders
- Rougly minimizing profits

From the typical European model, there is no aim at the Walrasian equilibrium. Such a setting then enables to deal with the non-convexity of the electricity markets and the combination of the both approaches significantly improves the implemented market model. The task is solved by standard Lingo software solver and the results are converted and aggregated within the MS Excel environment.

5.3.3. Semi-Langrangean Relaxation

To deal with such a kind of contrains, the Beltran et al. (2008) developed a new concept called Semi-Langrangean Relaxation. Here, the optimal integer solution is generated within the equality constrains.

In terms of the optimization method, the problem of searching for an optimal distribution of the system load to generation is called Economic Dispatch (ED) problem. In our case, a valuable approach is suggested by Min (2008), as he proposes methodology for the non-smooth fuel functions, even though this method is not suitable fot the multiple units due to their non-linearization. The solver is commonly the Langrage multiplier method.

Assume that A, b, and c in the following primal problem are nonnegative:

$$\begin{aligned} & z^* = \min c^T \\ s.t. \quad & Ax = b \\ & x \in S := X \cap A^n \end{aligned}$$

The Lagrangean relaxation, as explained earlier, consists in relaxing the linear constrain (constraint asi taky není špatně, ale v předchozích větách máš constrain) and solving the dual problem:

$$z_{LR} = \max_{\lambda} \wp_{LR}(\lambda)$$

and after plugging the previous in, we get:

$$= \max_{\lambda}\{b^T u + \min_{x}\{(c - A^T \lambda)^T x \mid x \in S\}\}$$

The Semi-Lagrangean problem is more constrained than the Lagrangean problem. If we consider extreme positive value for λ, and rewrite L SLR (λ) as:

$$\wp_{SLR}(\lambda) = \min_{\lambda}\{c^T x + (b - A^T x)^T \lambda \mid Ax \le b; x \in S\}$$

5.3.4. Model with capacity payments (Model CP)

As a default setting, a Spanish version of the capacity payments is implemented with the annual payment of 28 euros/kW of installed capacity per year. Thus the revenue of the operator changes to the

$$R_{i,j} = q_{i,j} * P + I_{i,j} * CP_{i,j}$$

where $CP_{i,j}$ denotes the capacity payment of the particular producer according to its capacity installed $I_{i,j}$

However, these payments are realized only in the peak seasons when there is a general demand for the peak capacities. Thus, the payment requires the total available capacities not surpassing the peak demand by 25 percent where the capacity payment mechanisms starts to operate and the payments increase linearly up to the CP_rate equal 28 euros/kW installed for the total capacities/peak_demand ratio reaching 1.1.

$$CP_{i,j} = -CP\_rate/0.15*(\sum_{i=1}^{k} \sum_{j=1}^{p} I_{i,j}) + (28-1.1*CP\_rate/0.15)$$

5.3.5. Model with strategic reserve (Model SR)

Within the strategic reserve, the producers are remunerated by two types of payments. Firstly, the system operator pays for the available capacity and secondly for the actual production during peaks. As the producers qualify themselves into the program based on the production costs and the time they need to offer full availability, a part of the gas-fueled production equal 2000 MW is identified within the production mix and moved into the strategic reserve scheme.

The operation starts only when the inelastic demand cannot clear with the available supply and in the default setting the corresponding price is set to clear at 3000 euros/MWh (as suggested by Nicolosi, 2012) in order to incentive for the market driven capacity development.

The model of the energy-only market stays the same while the only the producer within strategic reserve is remunerated by a fixed payment at the level of its fixed annual costs and the clearing price in the cases of the strategic reserve operation. Thus, his revenue R_{SR} is simple sum of SR_fix and SR_var (by default = 3000) in the cases when demand exceed suppy.

5.3.6. Model with capacity auction (Model CA)

Within the design of the capacity auction, the default energy-only market is augmented by the capacity auction on the capacity markets. Here, the producers strive to bid the aggregate amount desired by the central regulator.

In the initial default setting, a scenario where the central regulator correctly estimates the aggregate peak demand D is analyzed. The producers offer their capacities within the auction according to their fixed costs adjusted for the profits gain of the energy-only market. The offer of the regulator is thus the

$$O_{i,j} = (FC_{i,j} - Profit_{i,j}) z_{i,j}$$

The marginal offer needed is then the clearing price P_{CA} for the whole electricity market and the profit within the capacity auction scenario is set as

$$Profit\_CA_{i,j} = Profit_{i,j} + O_{i,j} * \text{accepted}_{i,j}$$

where the variable accepted is binary and it holds that $\text{accepted}_{i,j} = 1$ for $0_{i,j} <= P_{CA}$ and $\text{accepted}_{i,j} = 1$ for $0_{i,j} > P_{CA}$.

6. Results

The model simulates the operation on the German electricity market during the 8784 hours of the year 2012. The optimal production of the individual generations is indentified and the corresponding payoffs are calculated. The first part of the analysis focuses on the actual operation without any capacity remuneration mechanisms known as the energy-only market. As the payoffs do not fully cover the operation for some producers because of the low number of hours in operation, the second part of the analysis focuses on the changes in payoffs if the individual capacity remuneration mechanisms are implemented.

6.1 The "missing money" problem hypothesis

The model of the energy-only market strives to prove the following hypothesis:

H1: There is a significant "missing money" effect on the German electricity market

To prove or reject this hypothesis, the following setting is defined within the software Lingo. This demonstration is an advanced version of the demonstration of the Madrigal (2008), but applied on the conditions of the German market. The model settings are more closely describe within the methodological part.

In principle, with regard to the real demand of the particular hour in the year 2012, the solver puts the cheapest set of generators in the operation. The costs and the revenues are calculated for the given period of the time including the profits of the individual generators. The mechanics of the process are carefully observed in order to be potentially improved by the capacity remuneration mechanisms.

For the given hour, say between the 00:00 and 01:00 on the 1st January 2012, the sample market situation looks as following:

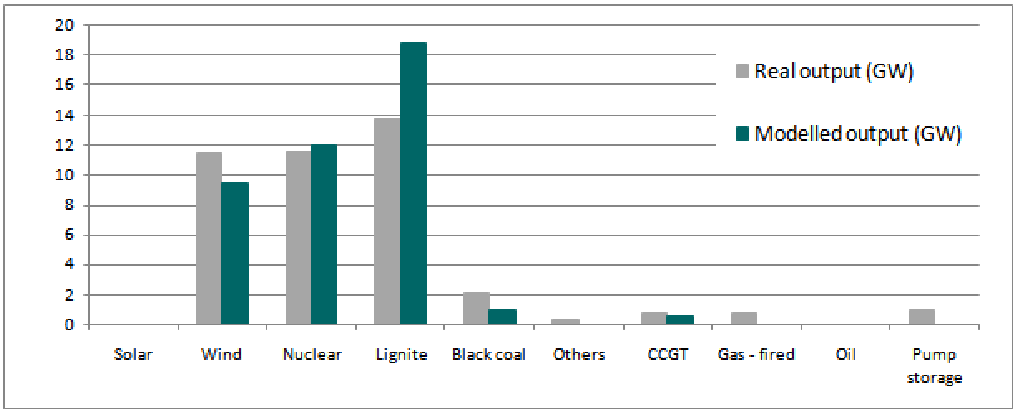


Figure 6.1.1: Real vs. predicted power output (GW) on 1.1.2012

The only larger deviation is for the lignite which is approximated on the average values. This is not a systematic bias as the lignite was unsually low this day (lignite and nuclear create a steady 30 GW baseload that deviates infrequently), nevertheless it is a fair illustration of the uncertainties the model has to face. The individual profits have evolved for the individual producers as following:

	Production GW	Marginal cost EUR/MWh	Profit/Loss EUR/MWh	PnL at 42.59 EUR/MWh	PnL at 60 EUR/MWh
Solar	0	0.0	0.0	34.2	48.6
Wind	9 500	0.0	17.4	34.8	49.2
Nuclear	12 077	10.8	2.3	19.7	34.1
Lignite	18 778	20.1	-3.1	14.4	28.8
Black coal	1 007	31.2	-13.6	3.8	18.3
Pump storage	0	**49.0**	0.0	-17.9	**-3.5**
Others	0	**53.0**	0.0	-13.7	**-0.4**
CCGT	500	**54.5**	-32.6	-15.1	**-1.9**
Gas - fired	0	66.0	0.0	-44.1	-33.12
Oil	0	81.3	0.0	-134.7	-38.71

Table 6.1.: Individual payoffs under various prices

Obviously, the very low night hours did not allow even the lignite producers to reach profits. From the perspective of the whole year, the average price of 42.59 allows the mainly baseload producers to stay profitable, while the price is too low for the peak producers. Importantly, even the price of 60 euros does not compensate the producers from the missing money effect compared to its time in operation during the year. Based on the simulation, the production generated by sources equaled:

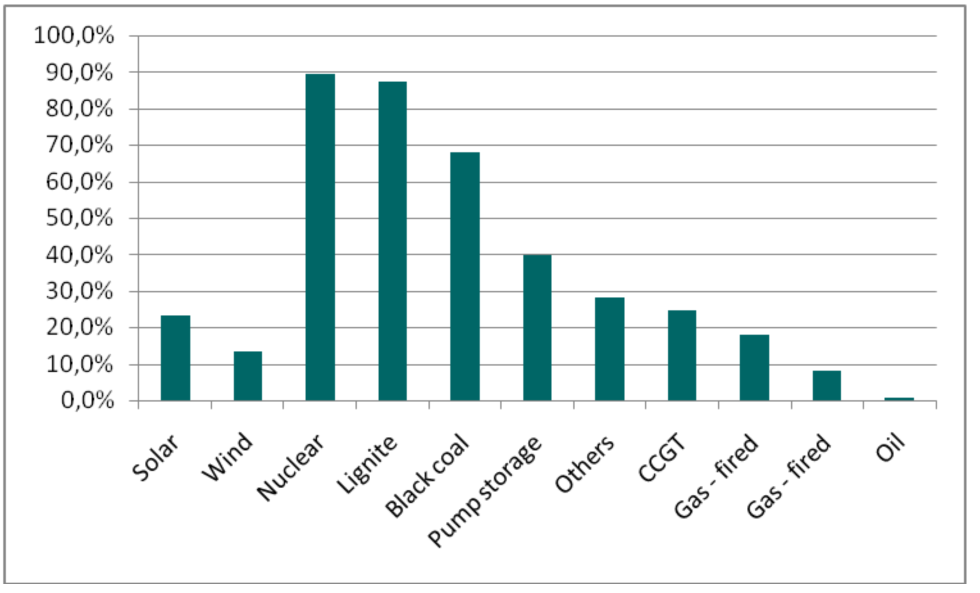


Figure 6.1.2:.Time in operation during the year (in percent)

As main aim of the simulation is to reveal the mechanics behind the market solution and to identify the conditions when all generators can survive because of the scarcity rent materialized in the higher spot prices during the peaks.

For the CCGT unit, an average annual time in operation was 2966 hours (33.8 percent of time). To become break even, the plant needs to split its costs within these hours as well. The trade-off between higher price and the time in operation can be depicted in the following way:

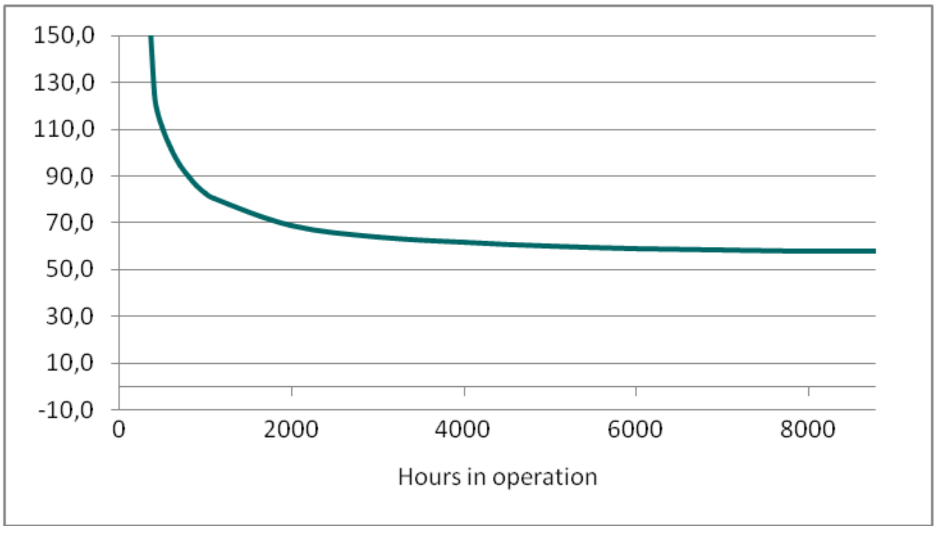


Figure 6.1.3:.Price needed for the CCGT to be break-even

It is important to say that the more peak oriented the producer is, the harder is to pay its annual fixed costs. With 1000 hours annually in operation, the break even price is 82.7 euros and with further decreasing time the price starts to rise very steeply. For producers who would aim to cover only the top 1 percent of the peaks (88 hours annually), the break-even point is already about 375.4 euros.

When aggregated, the individual producers reach the following payoffs:

Producer	EUR/MWh	Time in operation	EUR/MW
Solar	34.2	23.4%	70 315
Wind	19.4	13.2%	22 520
Nuclear	20.0	89.3%	156 532
Lignite	14.9	87.4%	114 106
Black coal	4.0	68.1%	23 807
Pump storage	2.1	39.7%	7 319
Others	-6.9	36.7%	-22 217
CCGT	-7.6	33.8%	-22 543
Gas - fired	-16.7	15.9%	-23 265
Oil	-591.1	0.7%	-38 776

Table 6.2.: Profits and losses for 1 MWh of production and 1 MW of capacity

To sum up, the simulation on the German power market reveals that the marginal pricing of the production leads to the missing money problem. Firstly, the producers with the steady production and in operation during most of the time are highly profitable. Secondly, even though the black coal production is generally volatile on the day-to-day basis, it omits the production during the low-price hours which enables to reach the profits.

For the peak producers, the overall results during 2012 were negative. Even though they have tried to reach the scarcity rent through the operation during the peak hours, they safely covered only their marginal costs. The loss is within the range (18 – 29 EUR/kW) of the capacity remuneration in the other countries.

There are two reasons behind the loss ifself. Firstly, the electricity prices are at their record lows. When the prices soared in 2008 on 90 euros/MWh or even later declined to 60 euros/MWh in 2009, the fixed costs were easy to be paid as they do not move much in time. This is in contrast with the marginal costs as their fuel tends to move with the business cycle. Secondly, it is the increase in renewable resources that decreases the time in operation the investors have planned. This is not a big news for the current facilities that are already running, however from the long-term point of view it disincentivizes the investors significantly.

To understand the mechanisms behind the results, one must bear in mind that during the year 2012, there were only 31 hours with prices above 100 euros. Thus, for oil plant being in operation for 65 hours during the year was an unprofitable business. Even though the variables have paid themselves immediately, there is a clear loss of -456.1 euros/MWh. On the other hand, even though such a loss looks scary, the year 2012 was a year with very low baseload prices. The plant is already standing, it might have had very good financial results during the previous years with higher prices and it is currently waiting for either higher average prices or more extreme spot situations when spot prices would be reaching about 400 euros/MWh.

Secondly, it is important to reflect the potential impacts the trades over the border. One potential explanation for Germany (and other countires) still keeping the energy-only market might be the reason that some other countries in Europe have already employed such a scheme. In the peak hours, it is then cheaper to import the production because if the exporting country runs an electricity design with the capacity payments, there are more peak producers available and the price cleares at lower levels. On the contrary, if all European countries had energy-only markets, the excess capacities would be tighter and the spot prices would probably rise higher during the peak times.

6.1. The CRM is a solution in long-term hypothesis

The following model strives to prove the following hypothesis:

H2: Capacity remuneration mechanisms (CRMs) are a viable solution to ensure sufficient generating capacity in long term.

To prove or reject this hypothesis, the above sketched setting will be extended by three capacity mechanisms. The basic scenario is the energy-only market examined above. Then, there are three scenarios with different capacity remuneration mechanisms:

1. The capacity payments (CP)

2. The strategic reserve (SR)

3. The capacity auction (CA)

With the proper setting, that the profit of the very last producer should be equal zero under the assumption of the perfectly competitive markets. Under the proper setting, effectively working capacity auction or optimally set payments by the central regulator are understood. As already discussed in the theoretical part of the thesis, there are many market frictions that do not allow to reach this optimum. Nevertheless, the following simulation should help the reveal the optimal market design that delivers reasonable results under the condition of the current market characterictics.

Having proved the hypothesis one about the existence of the missing money problem, there are generally two ways how to tackle this problem. Firstly, as Joskow (2007) suggests, a decrease in the market frictions and overall improvement in the efficiency of the spot market together with higher volumes traded should improve the energy-only market enough to be able to remunerate the peak producers via the scarcity rent only without other options needed.

As this solution is really long-term and generally quite complex without a given roadmap, a viable solution for the reduction of the missing money problem would be the second option: any kind of remuneration that would cover directly the fixed costs regardless the share of the time in operation. The capacity remuneration mechanisms seem to be that option as the size of the fixed costs is a function of the capacity installed.

The empirical confirmation of the hypothesis gives for the example the PJM power market as the capacities installed have been steadily increasing during the 10 years in operation just as planned by the regulator who sets the target production.[6]

The corresponding simulation confirming the statement is carried out within the test of the third hypothesis testing.

[6] The 10 years figure might be confusing since PJM started in 2007, but it has traded capacities for 2017 early this year as the trading occurs three years in advance.

6.2. The CRM is an optimal solution within Germany hypothesis

The following model strives to prove the following hypothesis:

H3: Capacity payments are the optimal CRM model with the highest effectiveness in terms of the current German market.

The effectiveness stands for the generation of the sustainable environment that would incentivize the potential investors for investing if they assess the capacities as insufficient. The model is not multi-period and does not contain any mechanism simulating the decision making of the investors themselves as we assume that a probability of the stable and decent future returns (potentially ensured by the capacity markets) within the peak generation will attract the rational investors itself. An empirical proof for this assumption might be again the PJM market where the period of 3 years between the selling the capacities and the delivery give investors a chance to hedge their fixed costs even before the realization of the project.

Moreover, as the hypothesis is designed as a policy recommendation, the thesis also discusses the pros and cons of both options with regard to the aspects concerning the potential implementation in Germany or the European level.

Technically, based on the methodology introduced above, the simulation delivers following results:

	Model CP	Model SR	Model CA
	EUR/MW	EUR/MW	EUR/MW
Solar	70 315	70 315	69 331
Wind	22 520	22 520	22 520
Nuclear	156 532	156 532	156 532
Lignite	114 106	114 106	114 106
Black coal	51 807	23 807	47 072
Pump storage	35 319	7 319	30 584
Others	5 783	-22 217	1 048
CCGT	5 457	-22 543	722
Gas - fired	4 735	-23 265	0
Oil	-10 776	-38 776	.
Gas in SR	.	28 240	.

Table 6.3.: Payoffs of the individual producers

Firstly, the least convenient seems to be the Swedish version of the strategic reserve. Even though the capacity would be ensured during the year via the gas power plant in the regime of the strategic reserve, the “missing money” problem is not significantly dealt with under the current setting. This would presumably lead to disincentivizing investors to install new peak capacities and to the grid endangerment in the future.

Secondly, the capacity payments scheme seems as a quite powerful way of dealing with missing money. The losses of the peak producers have improved significantly while a transparent scheme determining the size of the capacity payment is set. Unfortunately, this aspect is hard to quantify but is should be considered as beneficial for investors. Mainly with regard to the current drop in the prices from the capacity auctions in the PJM market.

Thirdly, the simulation of the scenario with the the capacity auctions can be considered as the most effective viable solution for missing money problem prevention. The auctioning process of the future capacities has ruled out the oil-fueled producers in favour of the gas-fueled capacities. This process would not happen immediately on the energy-only market as the prices are subject to uncertainty and the oil producers might continue the operation believing in the future demand that would bring sufficient prices. The prices have decreased which diminishes the profits of other producers.

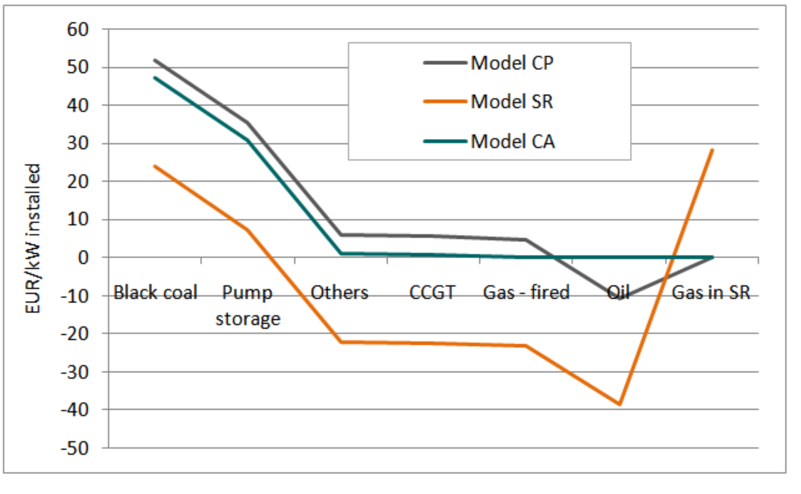


Figure 6.1.4: Profits and losses for 1 MWh of production and 1 MW of capacity

To conclude, the capacity remunerations cleared at 28 EUR/kW (capacity payments), 28.240 EUR/kW (strategic reserve) and 24.249 EUR/kW (capacity auction). The choice between the capacity payments and the capacity auction is a tradeoff between lower effectivity balanced by transparently certain price in long-term and the most effective capacity pricing with the cons of the dynamically evolving price with uncertainties for investors. Even though the choice is a bit arbitrary, I am in favour of the capacity auctions as here I personally believe market to make the best decisions given the information available.

7. Discussion

The results comply with the EWI (2012) and Khafallah (2012) who favour the market based capacity mechanisms. Similarly to Khafallah, we find the strategic reserve as inefficient in dealing with the missing money effect. The results also comply with Joskow 2007, as in case of the strict marginal pricing the missing money converge equal the investment costs.

On the other hand, Nicolosi (2012) suggests for Germany a strategic reserve, however the analysis is mainly synthetizing work of other authors without any own simulations and it is hard to identify the determinants of the different results.

Just to answer all questions raised in the thesis, changing the marginal costs of the renewables from zero to the values suggested by literature did not change the results at all. As there has never been the situation of renewables producing the whole power alone (even though it is theoretically possible, the solar generation is correlated with demand positively), the renewable energy sources initiate only the merit order effect and by shifting out only the most expensive generators out of the market, but not all of the conventional sources who set the marginal price.

The most sensitive input of the analysis is the German power price. In fact, one of the key reasons behind the intensive discussion of the capacity remuneration markets are probably the steadily falling power prices. Five years ago, the profit margins on electricity were significantly higher and to call for the capacity remuneration for the peak capacities (who could have been also in red numbers but who are usually assets of the producers who were viewed as “fat cats” at that time) would have no political support.

Second sensitive parameter is the level of peak capacities on the other markets that can accommodate the peak increases without increasing prices significantly. In fact, there can be a free riding situation when market runs an energy-only design but trades with country with capacity remuneration mechanism.

8. Conclusions

The thesis follows the actual events as the European Union sets the goal to increase the share of the renewable energy sources (currently set as 20 percent of renewables until the year 2020). This can constitute an increase in renewable energy sources in the electricity to 34 percent, which will be a fundamental challenge for the European electricity markets.

The vast investments into the renewable sources of energy and the practically zero marginal costs of renewable result in less operating hours for conventional plants which negatively influences their profitability and thus endangers the stability of the grid. Moreover, the German 2014 baseload power price has declined to about 39 euros/MWh at the end of July 2013 and clean-spark spreads (a proxy for the margin of the gas-fueled producers) have been negative since February 2013. Jointly with steadily decreasing time in the operation, conventional producers strongly articulate the unsustainability of their operation.

As the electricity market designs allow for several measures to ensure sufficient generation capacity in long term, the thesis has thus two objectives to fullfil. Firstly, to test the hypothesis whether there is currently a “missing money” problem which is done by a dynamic programming model on the German 2012 power market data and the non-convexity of the supply is dealt with by the Semi-Lagrangean approach. The results confirm that there is a significant missing money problem for the peak generators as their share of time in operation ranges from 68.1% (hard coal) to 0.7% (oil). This results in the pnl ranging from 23 euros/kW (hard coal) to minus 38 euros/kW of the capacity installed (oil).

Second part of the analysis compares the effectiveness of the capacity remuneration mechanisms. Three types of the capacity remuneration mechanisms (CRMs) are implemented (capacity payments, strategic reserve and capacity auction) in order to deal with “missing money” which mostly eliminates the missing money problem depending on the setting. The most effective CRM seems to be the capacity auction model as the price is set dynamically by the market players and not arbitrarily by central regulator. Second-best option are the capacity payments, while the strategic reserve did not solved the missing money problem under given conditions.

By some authors, the question of effectivity would be considered questionable as they consider investors as averse to fact that under capacity payments the future capacity price development is uncertain. On the other hand, there are surely investors who are probably averse to the shift from their risk exposure from market risk to the increased regulatory risk as the central regulator would decide about the demand.

To summarize, the capacity remunerations cleared at 28 EUR/kW (capacity payments), 28.240 EUR/kW (strategic reserve) and 24.249 EUR/kW (capacity auction) which is in line with the capacity prices in other countries.

The thesis further supports the creation of the demand flexibility scheme due to the expected low costs. Even though the exact figures are hard to review for Germany, American experience suggests that the first few GW of capacities are cheaper by 50 percent compared to the new capacities.

Last but not least, the capacity mechanisms should be viewed mainly as the transition measure on the way of increasing market efficiency and eliminating market frictions.

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Appendix A: Estimate of the annual capital and operating costs

	Capital costs	Life time	Annual CAPEX	O&M annually	EUR/USD*	**CAPEX + OPEX**
	USD/kW	years	USD/kW	USD/kW	0.7699	**EUR/kW**
Lignite	3246	35	92.7	37.8		**100.5**
Hard coal	3014	35	86.1	37.8		**95.4**
Natural gas	917	25	36.7	13.17		**38.4**
Uranium	5530	40	138.3	93.28		**178.3**
wind	2213	25	88.5	39.55		**98.6**
Solar	2387	25	95.5	24.69		**92.5**
Pumped Storage	5288	55	96.1	18		**87.9**
Oil	917	25	36.7	13.17		**38.4**

Source: EIA 2013, VGB 2012