Focused capacity markets. A new market design for the transition to a new energy system

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Dr Felix Chr. Matthes (Öko-Institut)

Ben Schlemmermeier (LBD-Beratungsgesellschaft)

Carsten Diermann (LBD-Beratungsgesellschaft)

Hauke Hermann (Öko-Institut)

Christian von Hammerstein (RAUE LLP)

Öko-Institut e.V.
Berlin office
Schicklerstraße 5–7
10179 Berlin
Tel.: +49 -30 - 280 486-80
Fax: +49 - 30 - 280 486-88

www.oeko.de

LBD-Beratungsgesellschaft mbH
Stralauer Platz 34
EnergieForum
10243 Berlin
Tel.: +49 - 30 - 617 85 310
Fax: +49 - 30 - 617 85 330

www.lbd.de

RAUE LLP
Potsdamer Platz 1
10785 Berlin
Tel.: +49 - 30 - 818 550-330
Fax: +49 - 30 - 818 550-107

www.raue.com

Executive Summary

The German and European power supply systems face extensive changes. With the energy policy decisions made in 2010 and 2011 Germany has set itself the goal of comprehensively reducing the greenhouse gas emissions of electricity production by the middle of this century, of shifting its basis largely to renewable energies and of phasing out the use of nuclear energy by 2022. At the same time the transitional phase of opening up the electricity markets to competition is drawing to an end. In the last decade the electricity demand in Germany not covered by renewable energies was chiefly fulfilled by power plants built prior to the liberalisation of the electricity market and re-financed within the scope of the electricity market monopolies which lasted up to 1998. This comfortable situation will radically change in the years ahead. Nuclear power plants will be permanently shut down, and the developments on the natural gas, hard coal and carbon markets, and the increasing pressure of competition will jeopardise existing power plant capacities and not allow investments in new flexible power plants. This situation is primarily a result of the price-setting mechanisms in the liberalised electricity market since the market was opened up to competition on the basis of a power plant fleet which was built during times of monopoly, is capital-intensive and largely depreciated, and has comparably low operational costs. The large-scale expansion of renewable energies and the current price crisis of the EU Emissions Trading Scheme further intensify this trend substantially.

Alongside the phase-out of over 20,000 megawatts of electricity capacity from nuclear power plants, more than 10,000 megawatts of capacity from incumbent power plants are at acute risk of decommissioning. In addition the building of approx. 5,000 megawatts of new power plant capacity up to 2020 and at least an additional 10,000 megawatts up to 2030 has to be ensured to flank the planned expansion of renewable energies with residual load power plants which guarantee security of supply. Germany's network is part of the interconnected Continental European power system, but a closer analysis shows that power plant capacities from abroad cannot make a significant contribution to guaranteeing security of supply in Germany in the medium term.

Within the current set-up of the German electricity market, the optimisation of power plant operation plays an important role, but is reaching its limits in terms of financing power plant capacities. Thus a re-design of the electricity markets is necessary. A re-designed market of this kind must – alongside electricity production – also generate a revenue for the provision of power plant capacities. Corresponding market models have been implemented and tested internationally in a variety of ways. A range of relevant suggestions has been put forward for Germany; these suggestions have a number of disadvantages on the one hand and do not sufficiently reflect the range of upcoming challenges on the other hand.

A capacity market instrument primarily serves to guarantee security of supply; yet objectives such as maintaining competition intensity, minimising costs for electricity consumers and meeting at least Germany's climate policy targets also have to be taken into account. In addition a contribution has to be made to transforming the power supply system; the building of new, very flexible and low emission power plants which complement the fluctuating electricity production from wind and solar energy is essential for technical and economic reasons.

In view of these criteria and the problems of the capacity market models put forward to date (strategic reserve, a comprehensive capacity market), the concept of the “focused capacity market” is being developed. This design option for a capacity market consists of two different segments, for which separate auctions are carried out and in which different power plants as well as measures for flexibilising electricity demand and storage can participate. In the “incumbent power plants” market segment, power plants at risk of decommissioning compete with dispatchable load (demand response) for capacity payments for one or four years. In the “new power plants” market segment, power plants which fulfil high flexibility demands and environmental requirements and new electricity storage compete for capacity payments over 15 years. The capacity payments of different duration increase planning security for investors and plant operators while decreasing risk premiums and thus the costs for electricity consumers.

The distinction between the two segments makes it possible to tailor capacity payments to useful time periods, enables the productive incorporation of controllable loads and storage, and extensively avoids free-rider effects. The rigorously competitive set-up of the tendering procedure generates high competition pressure and ensures low prices. The possibility that the successful bidders in the capacity auctions are regular participants in the electricity and energy market maintains the competition intensity in the power market, at least partly avoids erratic scarcity prices and the corresponding burden for the customers, and facilitates the expansion of a highly flexible power plant segment, which is urgently needed in the future to complement the fluctuating renewable production from wind and solar energy. In addition there is the possibility of integrating regional aspects, in particular investments in new power plants, and thereby also contributing to easing the burden on the network.

The costs which are substantially curbed for the reasons mentioned are refinanced via the network use charges on the transmission network level.

By definition the system ensures a high level of security of supply. By implementing the system with call options, with which the tenderer can partially skim off the revenues of the successful bidders in the case of very high electricity prices, the power plants enjoying receipt of capacity payments are prevented from exercising market power and the costs are reduced for electricity consumers.

For the technical implementation of the focused capacity market a range of procedures (registration of the plants, identification of quantitative targets in a consultation procedure, auctioning, monitoring compliance, etc.) are necessary. However, these implementation measures also apply to a similar extent in the case of all other options and remain within limits. Focusing the capacity market on the two segments of “incumbent power plants” and “new power plants” also enables easy adaptation and implementation as a learning system.

Ideally a capacity market for Germany will be implemented within the scope of the integrated electricity market in Continental Europe. However, the institutional allocation of responsibilities in the current regulatory framework means that this cannot occur straightforwardly. Security of supply and therefore also the implementation of capacity markets has been the responsibility of national authorities up to now. A coordinated initiative of the countries of the Pentalateral Energy Forum (Germany, France, Belgium, the Netherlands, Luxembourg and from 2011 Austria as well) would be preferable, by means of which a model of this kind is implemented based on respective agreements, without making it necessary to create a uniform EU-wide regulation. However, this approach is faced with the problem that several neighbouring countries of Germany are already significantly further advanced in their discussion and implementation of capacity markets, which makes harmonisation substantially difficult. Nevertheless a consultative vote on the target levels for the capacity tenders necessary for the capacity market is useful and advisable.

A focused capacity market for Germany could be introduced comparably quickly. If the regulations enter into force within the course of 2014 and the sub-statutory and other regulations are introduced by 2015, the first auctions for power plant capacities could take place in 2015/2016. From 2017 onwards the first incumbent power plants and demand-side measures would be remunerated and ensured by capacity payments. From 2019/2020 the first new power plants could enter operation and the last two stages of the phase-out of nuclear energy (2021/2022) thereby substantially flanked.

The focused capacity market constitutes a pragmatic and, compared to the models of a comprehensive capacity market and a strategic reserve discussed up to now, a very advantageous instrument for tackling the current and foreseeable challenges with regard to security of supply. At the same time a focused capacity market can make a substantial contribution to flanking the transformation of the energy system to one based on renewable energies and maintaining a high intensity of competition in the electricity market while substantially limiting the costs for electricity consumers.

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1 Introduction and assignment

The power supply system in Germany (and also in Europe) is facing some far-reaching changes. On the one hand, there is the technical restructuring of the system in favour of renewable energies, and on the other hand, there are changes in the structure of the deregulated electricity market in Europe/the relevant submarkets (in the case of Germany, this is first and foremost the north-west European electricity grid).

In the first instance, these structural changes arise from the need for the first time since the beginning of deregulation in 1998 to make major investments in power plants that have to be entirely financed by the electricity market (in other words, income from other regulatory areas can no longer be taken into account, such as the free allocation within the EU Emissions Trading Scheme). This challenge which is intrinsic to the market is exacerbated by three factors: the massive increase in the volume of electricity generated from renewable energies, the current crisis in the EU Emissions Trading Scheme (with low prices for emissions certificates) and the marked increase in the price of conventional power plants.

In this context, discussions regarding capacity mechanisms are highly relevant. These are instruments that are used to make sure that revenues can be generated for making power plant capacities available or for corresponding measures to reduce the power load.

Discussions relating to such capacity mechanisms are conducted on a number of levels.

Firstly, the problem itself, i.e. the necessity of such instruments, is disputed. In this respect, the debate encompasses a wide array of economic theory arguments and differing evaluations of the real-world developments, but can ultimately be reduced to just a handful of axioms. Two different strands of discussion have come about as a result of scientific and political debate of the issue. One faction is arguing for a wait-and-see approach and, in this context, at the most for the development of some stop-gap instruments. The second faction accepts that the current market design fundamentally needs to be complemented by capacity elements (likewise on the basis of a considerable array of arguments) and therefore discusses various concepts that are largely dependent on individual interpretations of the problem and on the target systems. But this side of the debate is largely in agreement that the idea of competitive mechanisms for pricing power plant capacities or appropriate measures on the demand side needs to be pursued, in other words that volume management systems with free pricing and no administered capacity payments should be striven for.

Secondly, in the political debate in particular, there is a great deal of confusion regarding the courses of action for the various time horizons:

- Above all, the current debate is dominated by the necessity to create cold reserve in the short term to safeguard security of supply over the next three winters. The measures proposed in this respect are very much of a regulatory nature.

- This often overlaps with the debate about so-called strategic reserve. Rather than being a measure to solve short-term supply problems, this is an instrument that focuses on the expectation that the current problems can, sooner or later, be remedied within the current market design and that, at best, stop-gap solutions need to be developed.

Thirdly, in Germany and in many other countries in Europe there is also a discussion about complementing the current electricity market in the long term with new elements, in particular with a market for capacities. These capacity markets constitute a new segment of the electricity market which is designed with longevity in mind. Currently, the electricity market essentially comprises a segment for electricity supplies (energy-only market) and various segments for the short-term provision of system services (balancing power markets, etc.).

The primary aim of this analysis is to draw up a proposal for incorporating a capacity market into the current electricity (energy-only) market that satisfies both the current necessities (security of supply) and the long-term challenges (transformation of the power supply system on the basis of renewables and achievement of environmental protection targets) and that demonstrates the necessary degree of flexibility and adaptability in this context.

Rather than focusing on the fundamental discussions or a detailed account of the various situations, the expositions of this analysis will above all centre on the detailed description of a proposal that is so specific that it can play a constructive part in the necessary implementation discussion.

Our analysis will nevertheless begin with a detailed outline of the challenges being faced. Section 2 will outline the economic situation of new and existing power plants, with subsections 2.2 and 2.3 examining current power plant fleet developments in Germany and Europe in order to pinpoint the need for action as regards security of supply.

Section 3 outlines the point of departure for the discussions surrounding capacity markets from a broader perspective, i.e. also with reference to the upcoming restructuring of the power supply system in favour of renewable energies and the resultant need for action. The expositions of a new proposal for capacity markets, that is to say a focused capacity market, begin with specification of the aims of such an instrument (subsection 4.1) and a brief outline of some other model proposals (subsection 4.2) from which ideas for the design of the focused capacity market can be deduced. On this basis, section 0 will examine the basic concept and the key specifications of the focused capacity market, with these then being ascribed to the existing array of capacity instrument proposals in Germany in an overview in section 6.

The proposal for a focused capacity market presented here is specifically intended to be a contribution to the debate, with a view to accelerating both the process of specifying the problems and the implementation of a new market design for a new power supply system.

This study for the environmental foundation WWF Germany is, in part, based on numerous in-depth discussions with colleagues, political representatives, businesses and associations. We would therefore like to thank them all at this juncture. Nonetheless, the content of this study, in particular unclear issues and errors, is, of course, entirely the responsibility of the authors.

2 Background

2.1 The economic viability of new power plants and the economic parameters for existing plants

2.1.1 The margins of new-build power plants

The past decade saw highly dynamic developments in the underlying conditions of the energy industry and in the power plant markets:

- The fuel markets were characterised by a trend of rising prices and also by considerable volatility, which peaked in 2008.
- The CO_2 costs generated by the European Union Emissions Trading Scheme (EU ETS) introduced in 2005 were, as expected, quickly priced into the electricity markets and now constitute a new component of operating costs; there were relatively stable trends in the development of prices in the CO_2 market for brief periods, but the market is currently characterised by a massive slump in prices caused by a glut of emission allowances (Öko-Institut 2012).
- In the power plant markets, the prices of conventional plants have increased massively and are currently approximately 70% higher than they were ten years ago (Matthes 2012).
- The major promotion of electricity generated on the basis of renewable energies, in particular solar power generation, has resulted in huge slumps in peak prices, especially since 2010.

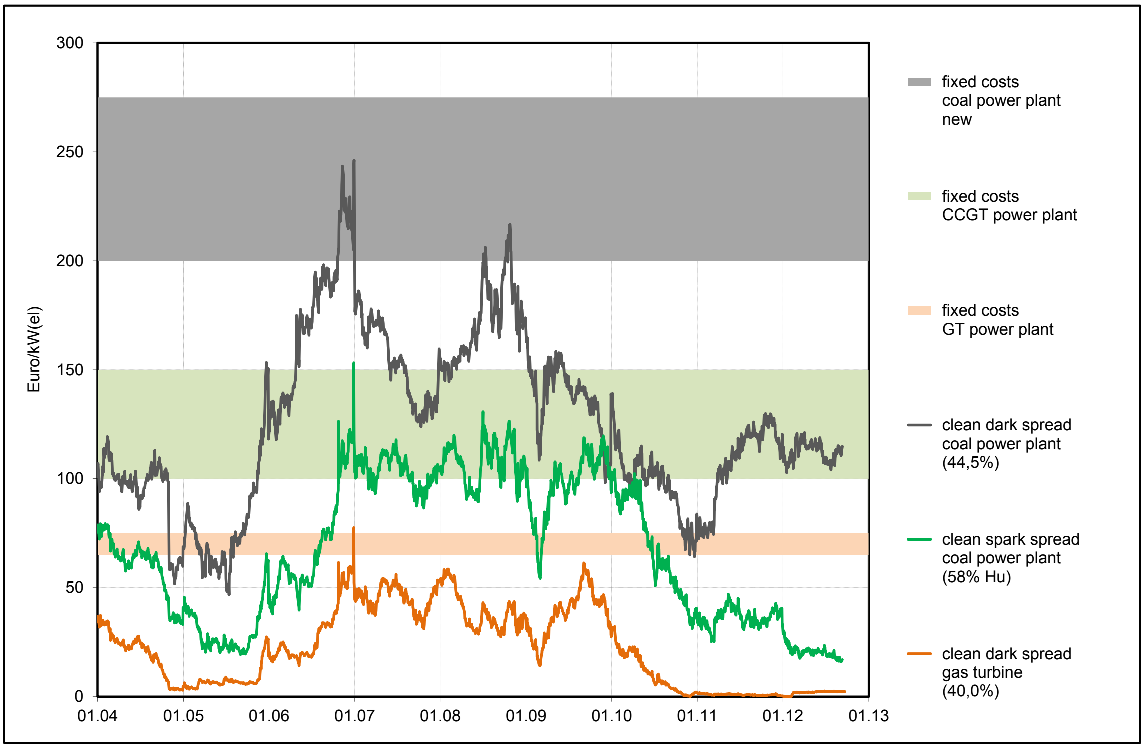
These fundamental trends have major consequences for the profit margins of new power plants, i.e. the generation of revenues to cover not only the operating costs, but also the investment costs and fixed overheads (HR, maintenance and overhauls, etc.) of new power plants.

Figure 1 illustrates the economic situation of various new-build reference power plants in Germany. The grey bar in the background represents the range of fixed costs for new coal-fired power stations (fixed operating costs and debt service), the light green background bar stands for the range of fixed costs for new CCGT plants and the orange bar is for the range of fixed costs for new gas turbine power plants. The lines track the power generation margins (contribution margins in relation to fixed costs[1]) for three different types of power plant: a new coal-fired plant, a modern combined-cycle gas turbine (CCGT) plant and a gas turbine power plant. The power generation margins for all three power plant types have fallen steadily since 2008. Moreover,

[1] The contribution margins are the difference between the revenues from plant operation and the operating costs relating to fuels and emission allowances. In the case of coal-fired power stations, these contribution margins are called ‘clean dark spread’, while they are known as ‘clean spark spread’ in relation to gas-fired power stations.

however, the current (and expected) contribution margins are a long way off even remotely covering investments in new power plants.

Figure 1 Development of contribution margins in relation to fixed costs for new-build power plants since January 2004



Source: EEX, Reuters, LBD analyses (as at 10/09/12)

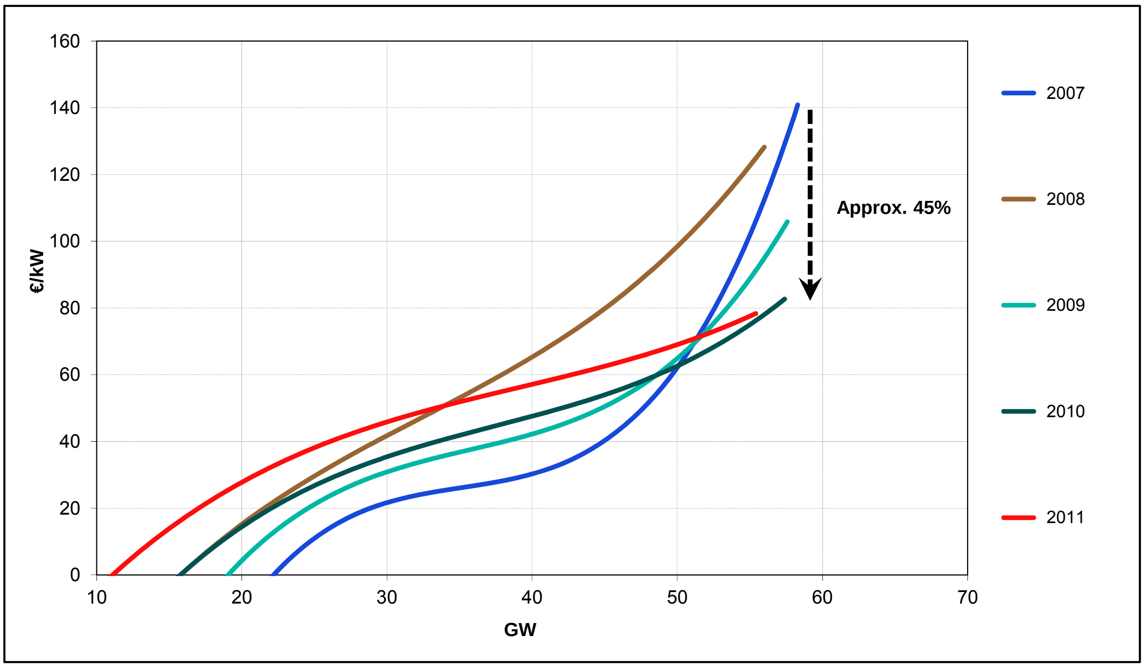
Since January 2004 (104 months), new coal-fired power stations (energy conversion efficiency of around 45%) were only able to cover the full costs in winter 2006 and in summer 2008 (five months in total). New combined-cycle gas turbine plants (58%) could only be operated at the lower threshold of full cost coverage between October 2006 and December 2010.

In the case of new power plants, a contribution margin of at least €100/kW is lacking for the fixed costs to be covered, no matter whether it’s a coal-fired or a gas-fired plant. The shortfall in the coverage of the fixed costs including debt service has now become so large that not even investments in CHP plants can make up the difference, even with CHP plants being funded (LBD 2012). And the cheaper gas turbines are likewise unable to generate a sufficient contribution margin due to insufficient hours in operation. The current and foreseeable margin situation will not result in adequate investments being made in updating Germany’s power plant fleet.

In addition to the above-mentioned factors, an increase in competition in the current market system is also to blame for this situation. The market operates as could be expected, given the existing regulations. It guarantees the short-term efficient use of the existing power plant fleet thanks to a high level of competition.

This is another reason why the wholesale prices for electricity in the upper peak range have been almost halved since 2007 (Figure 2).

Figure 2 *Spot prices based on the vertical grid load (third-degree regression curves), 2007 to 2011*



Source: 50Hertz, Amprion, Tennet, TransnetBW, EEX, LBD analyses

But this begs the question why a whole host of decisions were made to invest in new power plants in recent years in spite of these parameters. Upon closer inspection, these investment decisions, most of which came in 2008, can be ascribed to the following specific factors:

- Many of the decisions made in 2007 and 2008 were governed by the expectation that electricity, fuel and CO_2 prices would be very high in the future. Investment decisions were justifiable in the light of these expectations (efficient new power plants generate higher margins if the price of electricity, fuel and CO_2 is high).
- Some investors assumed in their decision making that the new power plants would at least temporarily benefit from the free allocation of emission allowances within the EU ETS and could therefore generate higher contribution margins.
- The premiums awarded for CHP electricity generation in accordance with Germany's Combined Heat and Power Act (KWKG) likewise allowed for higher contribution margins.
- The severe changes in the parameters of the energy industry and the massive promotion of renewable energies (above all solar power generation), which

have caused heavy price drops in the high-price segment of the wholesale market since 2010 in particular, were not foreseeable in 2008.

The decisions made in recent years relating to investment projects can primarily be explained on the basis of special situations or specific, but not ongoing, parameters. In contrast, the current difficulties relating to investment project decisions made in around 2008 have honed the investors' awareness of risks emanating from the parameters for the long term, thereby now making new investments in the power plant sector all the more challenging.

An analysis of the parameters for new power plant investments in recent years elucidates the reasons behind the extremely difficult environment for new investments in conventional power plants:

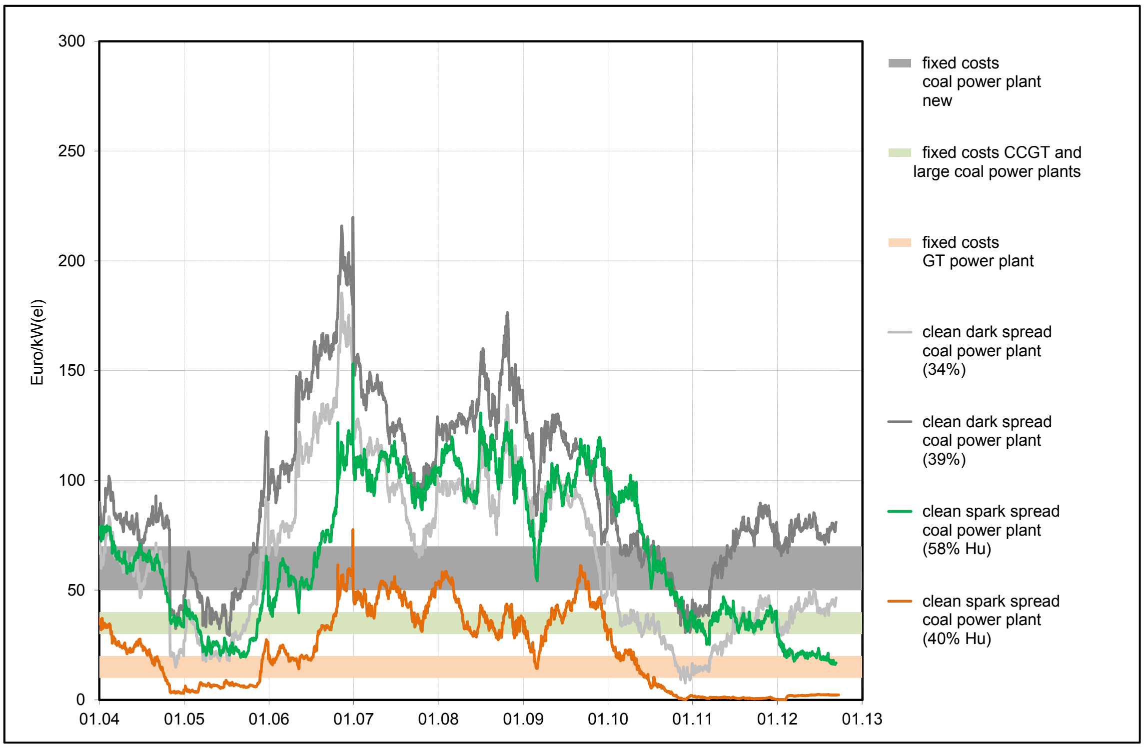
- The development of fuel and CO_2 prices
- The development of the vertical grid load and electricity prices
- Dwindling operating hours for conventional power plants
- Greater competition
- The loss of price highs during peak hours
- Higher investment costs for conventional power plants
- The loss of additional income sources (the free allocation of emission allowances within the EU ETS)

Unless there are major changes in the (energy industry and climate policy) parameters, substantial investments in conventional power plants will not be economically viable in the near future, even if the ongoing subsidy mechanisms such as those of the Combined Heat and Power Act (KWKG) are taken into account.

2.1.2 The margins of existing power plants

However, the margin situation has not only been exacerbated for new-build power plants. Figure 3 illustrates the margins of typical existing power plants and modern CCGT power plants in relation to their fixed operating costs.

Figure 3 Development of contribution margins in relation to fixed operating costs for existing power plants since January 2004



Source: EEX, Reuters, LBD analyses (as at 10/09/12)

The graph shows that the margin situation for older coal-fired power stations and ultimately for all gas-fired stations has dramatically deteriorated since the beginning of 2010. Of the examples of plants listed above, only the modern coal-fired power station is able to cover its operating costs in the current price environment. Older coal-fired power stations, modern CCGT plants and gas turbines each generate at least €10 per kilowatt (€/kW) too little to be able to cover the costs of staff, maintenance and overhauls.

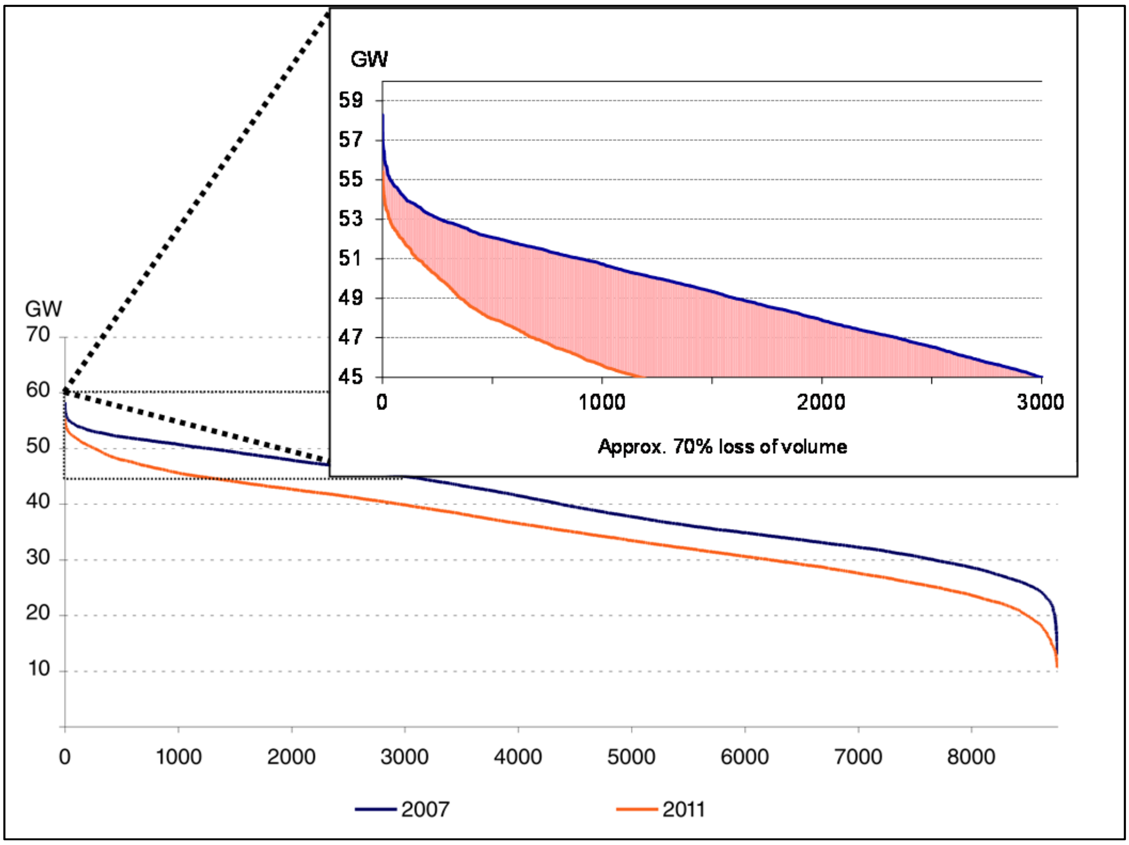
Power plants that are no longer able to cover their fixed operating costs need to be decommissioned. The fact that this has not yet happened to any substantial extent is above all attributable to the free allocation of emission allowances within the EU ETS. However, this source of income will completely dry up when the transition is made to full carbon certificate auctioning as of 2013, resulting in no more additional revenues.

Consequently, numerous power plants will have to be decommissioned in the next few years. This applies in particular to power plants that are rarely used. Plants with fewer than 1,000 operating hours will not be able to cover the fixed operating costs they incur at short notice (above all costs for staff and short-notice maintenance). Plants with fewer than 2,000 operating hours will no longer be able to refinance major overhaul and renovation investments. Considering the various maturities of the fixed operating costs, unless further measures are implemented, there will have to be a gradual withdrawal of the corresponding plant capacities. The first indications that older power plants are being decommissioned for economic reasons in particular are given by the level of recent decommissioning announcements submitted to Germany's Federal Network Agency (BNetzA)[2] by plant operators, which comfortably surpasses the anticipated level (cf. e.g. Öko-Institut 2011).

Figure 4 illustrates one of the key reasons for the decline in contribution margins. It shows the drop in the operating hours of conventional power plants in the transmission system since 2007 and clearly illustrates that in the peak load range in particular (demand >45 GW), electricity generation has fallen by around 70%. On the one hand, conventional power plants therefore have to cover their operating costs with an ever-decreasing number of hours, while on the other hand, the price of electricity when demand is high has fallen by approximately 45% in the same period (Figure 2).

[2] This data is now updated and published by the Federal Network Agency on a regular basis. The analyses presented here are based on the data available as at 12 September 2012.

Figure 4 Development of the vertical grid load as a benchmark for demand for conventional power plants in the transmission system



Source: 50Hertz, Amprion, Tennet, TransnetBW, LBD analyses

In the past twelve months, typical peak load power plants fired by gas or oil (gas turbines) could potentially be used for fewer than 150 hours and were not able to cover their fixed operating costs. However, the problem of shortfalls in contribution margins to cover fixed operating costs is no longer merely a challenge faced by older natural gas and coal-fired power stations. The current situation has even led to decommissioning now having also been considered for state-of-the-art CCGT power plants such as Block 5 of the Irsching 5 CCGT plant, which has an electric energy conversion efficiency of more than 59%.[3]

However, the pressure to decommission older natural gas and coal-fired power stations, possibly also new CCGT plants and even gas turbines will not result in numerous shutdowns all of a sudden. The costs of the necessary adjustment measures (e.g. as regards staff numbers) mean this process will only happen gradually, although the need to carry out more extensive maintenance and make sizeable overhaul investments at intervals of three to five years will ultimately determine when the decision is made to decommission a plant.

[3] Powernews, 21/09/12

The economic situation regarding covering fixed costs is also seriously exacerbated for a large proportion of the existing power plants, with the following factors playing a major part in this:

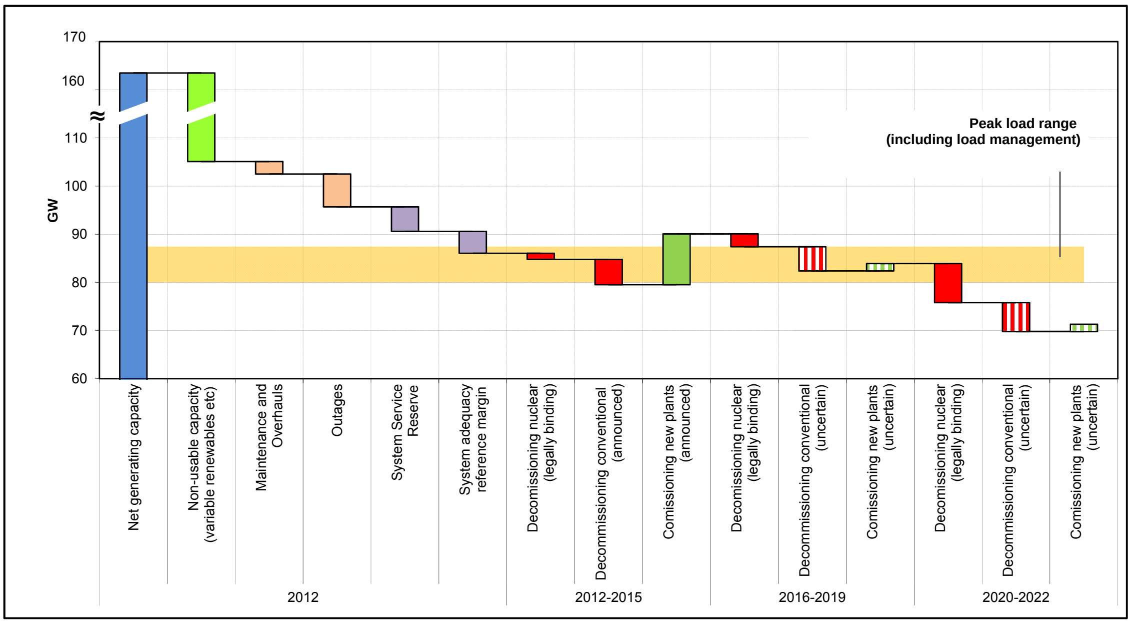
- The development of fuel and CO_2 prices
- The development of the vertical grid load and electricity prices
- Dwindling operating hours for conventional power plants
- Greater competition
- The loss of price highs during peak hours
- The loss of additional income sources (the free allocation of emission allowances within the EU ETS)

If the current (energy industry and climate policy) parameters prevail, substantial existing power plant capacities will increasingly have to be decommissioned in the next few years as of 2013 due to economic reasons.

2.2 The demand for conventional power plants in Germany

In spite of the macroeconomic situation, demand for guaranteed output, and therefore also the need for conventional power plants, will remain relatively high in the next 10 to 20 years. An estimate of the development in the residual load up to 2022 on the basis of Germany's 2012 grid development plan suggests that electricity generation demand from conventional power plants could fall by approximately 150 TWh per annum up to 2022. This corresponds to an approximately 49% share of electricity generation based on renewable energies. In contrast, there is next to no change in the peak load that conventional power plants have to provide/cover.

Figure 5 Development of Germany's capacity balance, 2012 to 2022



Source: ENTSO-E (2012), BNetzA, Öko-Institut calculations

Figure 5 shows the various factors influencing Germany's capacity balance in the next ten years.[4] Substantial proportions of all the installed net power plant output (in particular the capacities from the fluctuating generation of electricity on the basis of renewables) cannot be supplied with adequate reliability during peak loads. In addition, power plant capacities are not available when maintenance and overhauls are being carried out, nor are the reserve capacities set aside for system services (operating reserve, etc.) and security of supply (in the event of the outage of larger utilities).

In 2012, there was therefore power plant output of approximately 86,000 megawatts to cover peak loads. The current peak load, which was most recently estimated at

[4] The data presented here is in line with the system and methods upon which the European Network of Transmission System Operators for Electricity (ENTSO-E) bases its security of supply estimate (ENTSO-E 2012). The load data is based on the total load in the German power supply system.

approximately 87,500 megawatts (ÜNB 2012a), could therefore not be entirely guaranteed when all the requirements for system services and operating reserves were met.[5]

There will, however, be major changes affecting the capacity balance in the next three years:

1. Germany's Atomic Energy Act (AtG) prescribes the gradual decommissioning of Germany's nuclear power plants by the end of 2022. Up to and including 2015, this will affect a nuclear power plant with a power output of 1.3 GW.
2. The Federal Network Agency's data collection has considerably improved the data relating to the commissioning of new-build power plants up to 2015. According to this data, power plants with total output of 12.6 GW are set to be brought online by the end of 2015.
3. The German power plant operators' plans to decommission plants have become more transparent, likewise thanks to the data collected by the Federal Network Agency. These plans relate to shutting down fossil fuel plants with output of around 5.3 GW by the end of 2015. Some of these plants will have to be decommissioned in accordance with legal provisions, while others are set to be shut down for economic reasons.

If all the proposed new-build power plants are brought online in accordance with the current plans (although this cannot necessarily be assumed in the case of certain plants, such as the controversial Datteln power plant with 1.05 GW output), there would be power plant capacities of around 90 GW to cover the peak loads by the end of 2015.

However, this trend is more than likely to be reversed once again between 2016 and 2022:

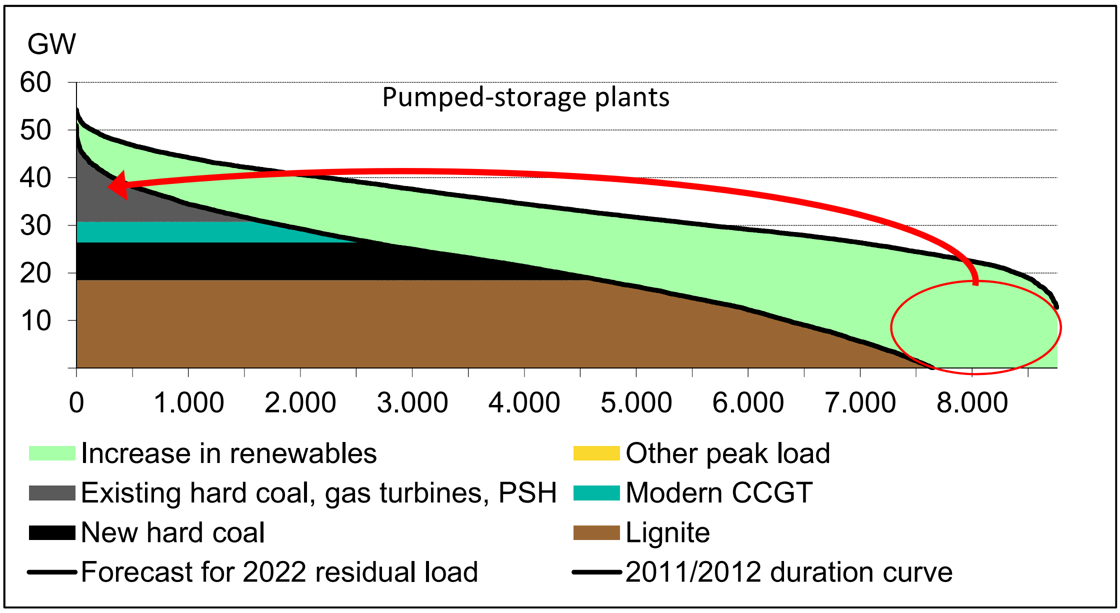
1. In four stages, the residual output of Germany's nuclear power plants amounting to 10.8 GW will be withdrawn from the grid.
2. In addition, other, conventional power plants will also have to be removed from the grid, with the economic situation described below resulting in particular in a great deal of decommissioning pressure. Ultimately, the volume of this decommissioning remains very uncertain, but could once again be as much as 10 GW.
3. At best, there is a strong possibility of an increase in new power plant capacities in the area of dispatchable renewables (above all biomass) and possibly also in relation to combined heat and power. In view of the current developments, little more than 3 GW of power plant output should be expected.

[5] At this juncture, it should be noted that, due to supplementary estimates relating to as yet unrecorded load requirements, the peak load data is subject to a degree of uncertainty. It can therefore be assumed that the security of supply margins will either be just missed or just met.

In addition to the developments in the areas of nuclear power plants, fossil fuel power generation plants and dispatchable biomass plants, smaller proportions of guaranteed output are also provided by other renewable energies (wind, photovoltaics). In view of the fact that there is currently no way of knowing whether biomass power plants, which are basically dispatchable, but which are not (yet) operated with the electricity market in mind in accordance with the subsidy system of Germany's Renewable Energy Sources Act (EEG), do actually contribute to guaranteed output, these contributions were not taken into account in the calculations above, in order to keep the estimate conservative.

In view of the aforementioned points, especial significance is attached to the development of the economic and technical parameters for the existing conventional power plants, which face a massive drop in the demand for power generation.

Figure 6 Development of the annual duration curve of the vertical grid load and use of the conventional power plant fleet, 2012 to 2022



Source: 50Hertz, Amprion, Tennet, TransnetBW, ÜNB (2012b), BNetzA, LBD analyses

Figure 6 shows the annual duration curve of the residual load (shown here with the vertical grid load as an indicator of the residual load[6]) and the power plant fleet needed

[6] The vertical grid load is the load demand covered by power plants feeding in electricity at the integrated network level. Power plants feeding electricity in at a decentralised level (these are first and foremost power generation plants based on renewable energies, the majority of CHP plants, etc.) are factored out, such that the vertical grid load is an accurate representation of the demand situation for conventional (large-scale) power plants. The residual load is the demand less renewable energy generation. It therefore accurately describes the proportion of the load to be covered by conventional power plants.

to meet demand. On the whole, it is evident that an increasing number of power plants are having to cover their fixed costs within a dwindling number of operating hours.

In the peak load area, there is competition between pumped-storage power plants, old coal-fired power stations and peak load power plants run on gas and oil. And it is in precisely this area that requirements have to be met by sufficiently flexible power plants. The old coal-fired power stations still available today will find it more and more difficult to deliver the necessary degree of flexibility. What's more, power plants will barely manage to generate sufficient contribution margins for their fixed costs in their limited hours of operation.

In addition, the existing power plant fleet faces considerable challenges as a result of the tightening of the parameters of the energy industry. The economic situation of power plants is also heavily exacerbated in the area of peak and medium loads by high coal and natural gas prices and low CO_2 prices (Öko-Institut/IIRM 2012).[7]

Consequently, unless the parameters change significantly, by the end of this decade, power plant capacities will have fallen back down to a level that means the (unchanged) peak load can just about be accommodated. However, with the last two tranches of nuclear power decommissioning and further shutdowns of conventional power plants, a situation will arise in which load reduction measures, the complementing of existing capacities and the commissioning of new power plants will become inevitable. Ultimately, for the time horizon of 2022, capacity volume of at least 10 to 15 GW will have to be guaranteed on the supply and the demand side. What's more, it cannot be assumed that the reserve plant capacities set aside for the eventuality of the outage of key utilities can be maintained at 5 GW without any additional measures being taken.

The period subsequent to 2022 will be characterised by the further expansion of renewable energies in power generation and therefore also by a further tightening of the parameters for conventional power plants, with these continuing to and increasingly having to deal with greater requirements on the one hand (a considerable contribution to covering the residual load in consideration of massively increased flexibility requirements) and the increased difficulty of covering their fixed costs on the other.

Distinctions have to be made between three stages in relation to conventional power plant capacity requirements:

1. The first stage will be driven in the short term by the necessity to keep existing power plants up and running and by the implementation of measures on the demand side to maintain security of supply, and will last until the end of this decade. To safeguard regional security of supply, it may, in individual cases, be

[7] It is precisely these changes in the energy industry parameters since spring 2011 that play a substantial part in explaining why the estimates of the volume of conventional power plants to be decommissioned have changed considerably in the past one to two years and are now much higher than the figure previously assumed by, for example, Öko-Institut (2011).

necessary to build new power plants in regions with infrastructure bottlenecks (in particular southern Germany) before 2022.

2. The second stage commences with the last stages of nuclear reactor decommissioning. The power plant fleet will then need to be increasingly flexible and this will also substantially increase the need for new, flexible power plants that will only operate for comparatively short periods.
3. In the third stage (after 2030), the high proportion of renewable energies will result in a greater need for storage technologies with various storage profiles.

The second and third stages are shaped by the higher proportion of renewables. With renewable energies accounting for (considerably) more than 50% of electricity in 2030, conventional power plants will have become less important still in terms of energy provision. But, together with measures for safeguarding security of supply on the consumer side, they will nevertheless have a key role to play as a flexible backup for renewables.

The estimates of the new-build requirements in the 2020 to 2030 decade range from 10 to 20 GW (cf. subsection 0), but here too, developments in the fuel and CO_2 markets and the impact of these add a great deal of uncertainty to the economic viability of the existing power plant fleet.

After all, the question of the degree of guaranteed capacity that’s needed also depends on how demand for electricity develops. But there is currently no way of knowing when or indeed whether the German federal government’s efficiency targets (a 10% reduction in gross electricity consumption by 2020 and a 25% reduction by 2050) will be met and to what extent the efficiency improvements will have an impact on peak load requirements.

In view of these two areas of uncertainty, it may be prudent both in the short and the medium term to contemplate also maintaining the existing power plants.

Finally, it should be noted that conventional power plant technologies such as gas turbines and CCGT plants will, from today’s perspective, continue to be very important for CO_2-free electricity generation for a long time to come, because these technologies are fundamental components of long-term storage facilities based on chemical energy carriers (hydrogen, etc.) that can be used to temporarily store surplus electricity from wind and solar power and then feed it back into the grid.

To summarise, we can make the following points about the conventional power plant fleet:

1. Conventional power plants will continue to play a pivotal role in the German electricity supply system for the next two to three decades, including as storage solution components in the longer term.
2. In the short to medium term, maintaining the existing power plants will have a relatively large role to play, in particular in the period up to the definitive discontinuation of nuclear energy, but also as a flexibility factor in view of the

many uncertainties (e.g. the development of electricity demand and the development of the energy industry parameters). For the next two decades, this probably relates to capacities within the range of 10 to 20 GW (cf. subsection 0).

3. The flexibility requirements made of conventional power plants will increase considerably over the next two decades, so highly flexible, new-build plants are likely to become more and more important at the latest from the end of this decade. This may cause demand of up to 5 GW up to the end of the decade, followed by a further 10 to 20 GW between 2020 and 2030 (cf. subsection 0).
4. Demand-side measures can play an important part too, but will not be sufficient to fully meet the above-mentioned capacity requirements (cf. subsection 0).

Although there is a great deal of uncertainty relating to the analyses of the various individual areas (or although they depend on a wide array of assumptions about future developments), there is, on the one hand, a generally robust picture. In this decade and the next, in view of the foreseeable parameters, some 15 GW per decade (give or take 5 GW) will have to be catered for by securing existing capacities, building new plants or implementing demand-side measures if security of supply is to be safeguarded and the restructuring of the power supply system in favour of renewable energies is to be supported.

On the other hand, the longer-term development is logically fraught with even greater uncertainty, and conventional power plant capacity requirements are dependent on the developments in the following areas:

- Development of longer-term load requirements and the volume of potential that can be tapped by means of demand-side measures
- Infrastructure expansion for large-scale electricity transmission and for decentralised dispatching (smart grids)
- Development of the various storage options and of the costs involved in these

The uncertainties in this respect are, and will continue to be, numerous, but it should be noted that conventional power plant technologies are key components of certain chemical electricity storage options (which will be relevant in the long term) and will therefore more than likely have an important part to play in the long term too.

The key parameters for discussing capacity instruments are the substantial dependence of the margin situation on the energy industry and climate policy parameters (i.e. fuel, electricity and CO_2 prices) and the vastly different contribution margin shortfalls in relation to the various fixed cost categories. In view of this, it is prudent and necessary to develop capacity mechanisms that make it possible to react flexibly to changes in the various parameters.

2.3 Relevant developments in Germany's neighbouring countries

In (Continental) Europe's increasingly integrated electricity market, security of supply can evidently no longer be evaluated without taking developments in neighbouring countries and regions into account. As peak load situations don't necessarily arise in the grids of the various different countries at the same time (although this is, of course, not ruled out), cross-border flows of electricity can play a part in achieving security of supply in neighbouring countries. The power plant fleet of the neighbouring countries[8] is not static, however, and is subject to change, in part for reasons similar to those in Germany, but also to an extent based on factors that have no bearing on developments in Germany:

- The energy industry parameters are the same for all the neighbouring states in Europe's highly integrated electricity market, so the existing power plants and new-build projects elsewhere are ultimately facing the same challenges as in Germany.[9]
- Much like in Germany, a number of countries in the regional market are working towards an exit from nuclear energy (Belgium, Switzerland) or have announced the closure of individual nuclear power plants (such as Fessenheim in France). Up to 2020 there will be marginal capacity decommissioning, followed by more significant decommissioning up to 2025.
- In contrast to Germany, considerable power plant capacities in its neighbouring countries (in particular Poland and France) are affected by permanent shutdowns made necessary by the EU's Industrial Emissions Directive (IED) because the plants fail to comply with the stipulated emission limit values for the conventional air pollutants or because they have made use of corresponding transitional provisions.
- In contrast to Germany, peak load requirements are likely to continue to rise in some of its neighbouring states, in spite of load management measures.

These factors are taken into account in the annual analyses of the European Network of Transmission System Operators for Electricity (ENTSO-E). The scenarios presented

[8] For two reasons of pragmatism, the following analyses do not encompass possible electricity supplies coming from Scandinavia. On the one hand, electricity will continue to be supplied from there, and the volume of supplies may even increase. But these supplies will reach Germany first and foremost in regions characterised by ongoing and considerable surplus capacity. On the other hand, strictly speaking, the analyses would also have to take into account the relations of electricity exchange from the Netherlands, Belgium and France to the UK, and also from the central European grid to Italy. But on the whole, the effects of these exchanges balance each other out and can therefore be disregarded here.

[9] The only exception to this relates to the free allocation of EU ETS emission allowances to power generation plants in Poland and the Czech Republic for a limited number of years beyond 2012 (EC 2012a+b). Power plants in Poland and the Czech Republic are able to generate income from these free allowances between now and 2019, albeit to a dwindling degree, and thus cover their fixed costs if necessary.

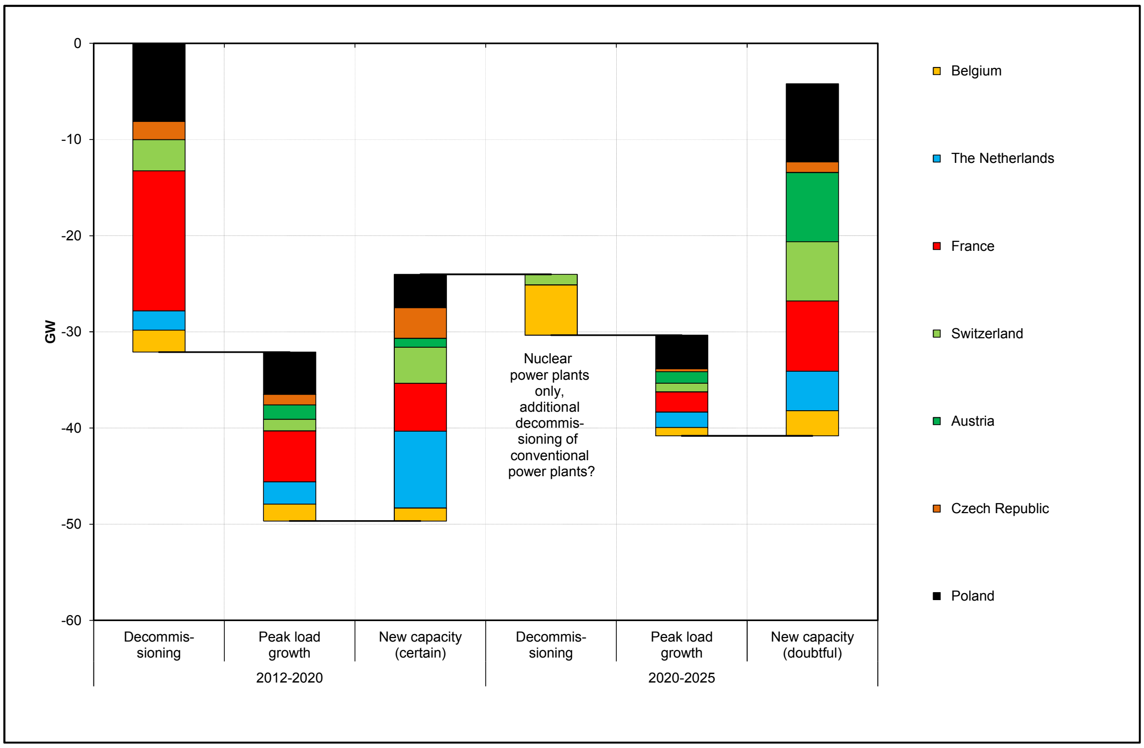
by the body in 2012 (ENTSO-E 2012) include an analysis of security of supply (system adequacy) for each individual member state and also for the various regional markets. Based on the most recent forecast up to 2025 and also drawing on other data sources, the capacity situation in Germany's neighbouring states was analysed:

- ENTSO-E's 2012 Scenario Outlook and Adequacy Forecast includes two well-founded bottom-up forecasts, namely a conservative scenario (scenario A) and a best estimate (scenario B).[10] These forecasts are based on the same reference points in time (the third Wednesday in January at 7 p.m. and the third Wednesday in July at 11 a.m.) and therefore implicitly take into account the variations in the times of peak load situations in Germany's neighbouring countries.
- The commercially available World Electric Power Plants Database produced by Platts (June 2012 edition) provides comparatively up-to-date details not only of operating power generation units, but also of power plants currently being built or in the planning stages.
- In addition, more in-depth information on specific power plant projects was researched for certain countries.

This data was used as the basis for determining an indicative capacity development up to 2020, as shown in Figure 7. The figure also features a forecast for further developments up to 2025, which takes into account the anticipated load increase and the power plant construction implicitly assumed in scenario B. The capacity developments of fossil fuel power plants, nuclear power plants, hydroelectric power stations (run-of-the-river, storage and pumped-storage power plants) and power plants run on biomass were taken into account. This results in a good approximation of the situation of the dispatchable power plant fleet.

[10] The report also features a top-down forecast based on the data in the member states' National Renewable Energy Action Plans. The reliability of this forecast is, however, limited in terms of the evaluation of security of supply.

Figure 7 Capacity developments in Germany's neighbouring states, 2012 to 2025



Source: ENTSO-E (2012), Platts World Electric Power Plant Database (06/2012), research, Öko-Institut estimates and calculations

The following overall picture of capacity development in Germany's neighbouring states therefore emerges:

- Between now and 2020, around 32 GW of capacity will be taken offline in the above-mentioned neighbouring countries. This relates above all to decommissioning for environmental reasons and, to a lesser degree, to the decommissioning of nuclear power plants in Switzerland, Belgium and France. The majority of decommissioning will be in France and Poland. Additional decommissioning triggered by the current and the foreseeable economic situation of older power plants in particular has more than likely not yet been included in this total capacity figure.
- Together with the anticipated increase in the peak load at the reference points in time, which ENTSO-E estimates at 18 GW (including the load management measures presented here), the available capacity is set to fall by around 50 GW. In the case of the anticipated increase in load demands too, the largest shares in this can be ascribed to France and Poland.
- The power plants already under construction and the projects that are more than likely to be realised will defuse the capacity situation by approximately 26 GW up to 2020, resulting in available total capacity in 2020 which will be around 24 GW lower than that of 2012.

- There is a great deal of uncertainty regarding the period after 2020. In particular, no reliable estimates can be made for the decommissioning of fossil fuel power plant capacities on the basis of the current data, so the chart only encompasses politically stipulated nuclear power plant decommissioning in Switzerland and Belgium.
- With the load increase stated by ENTSO-E (likewise taking into account the load management measures presented here), the capacity situation in 2025 is likely to be (at least) 40 GW below the level in 2012.
- In ENTSO-E's security of supply forecast, the scenario B time horizon includes total capacities that will, at the very least, make the new builds featured in the chart necessary. There is serious doubt as to whether commissioning new power plants up to 2025 with capacity of approximately 36 GW (3 GW of which in new nuclear power plants in Poland!) is even remotely realistic, given the foreseeable energy industry and energy policy parameters.

Overall, this approximate guideline analysis elucidates three key aspects of an integrated view of capacity developments in Germany and in the neighbouring countries with which Germany is affiliated in the electricity market.

- In a situation which is potentially characterised by capacities that are around 25 to 40 GW lower, it certainly cannot simply be assumed that the neighbouring countries will still be able to make substantial contributions to safeguarding Germany's security of supply in the future (as already illustrated by the analysis of the reverse situation in the previous section).
- Most likely with the exception of Austria and the Netherlands, which are set to have a positive capacity balance in the period under consideration here, Germany's neighbouring countries will, in view of dubious contributions to safeguarding their own security of supply, endeavour to secure capacities, build new plants and, where possible, tap the demand-side potential to a far greater degree.
- Thirdly, while the data (and also the transparency of how it is presented) has been improved by ENTSO-E's recent work, there is nonetheless an urgent need for the underlying data to be further substantiated and for the transparency relating to assumptions and their reliability to be increased. It is essential that the appropriate experience garnered from various processes in Germany (grid development plans, security of supply monitoring by BNetzA, etc.) be put to use here.

With regard to the pressure to take action, it can be stated that involving the neighbouring countries (if only on the basis of rough and guideline estimates) does not significantly change or defuse the situation or the problem of needing to secure and upgrade capacities in Germany, and, in consideration of the developments outlined above, can even exacerbate the situation.

At the same time, the neighbouring countries are indisputably facing similar challenges to those faced by Germany. The pressure to take action in Germany is replicated in some of the neighbouring countries likewise due to the discontinuation of nuclear energy (in particular Belgium), while in other countries (Poland, France), this pressure comes to a far greater extent from other (environmental policy) regulatory areas.

Both of these aspects need to be taken into account when developing the capacity market model presented in this analysis and then firmly establishing it in Europe.

3 The limits of the present electricity market model

Germany's current electricity market model essentially consists of three elements:

- The first of these is a wholesale market where, on the one hand, nothing but electrical energy ('kilowatt-hours') is traded. This market can then be broken down into three market segments. Firstly, there is the segment for forward deliveries in which electricity supply deliveries can be negotiated up to seven years in advance, but which only has sufficient liquidity for approximately three years. The second segment is the day-ahead market, in which, as the name implies, deliveries are negotiated for the following day. And then there is the intraday market segment, where electricity deliveries are negotiated for the current day. Within all three segments, only energy deliveries are traded (energy-only market) and pricing is competitive on the basis of short-run marginal costs (essentially the cost of fuel and CO_2).
- The second element is a system service market. This is above all for the provision of operating reserve (otherwise known as balancing power). This is needed in order to balance out the inevitable divergences from forecasts and for frequency stabilisation, because a real-time imbalance of power generation and demand will cause divergences from the frequency norm (50 hertz) and the frequency needed in order to uphold the supply quality has to be maintained within a very narrow tolerance range. The minutes operating reserve (activation within 15 minutes) is tendered by the transmission system operators centrally on a daily basis, either as positive (i.e. output increase) or negative (i.e. output decrease) operating reserve for a total of six time slots of four hours each. Secondary operating reserve (activation within 30 seconds) is likewise tendered centrally for the duration of a week. The primary operating reserve (up to 30 seconds) is likewise procured centrally by the transmission system operators and is tendered for periods of a week.
- Finally, the promotion of electricity generation using renewables in accordance with the Renewable Energy Sources Act (EEG) can be considered to be the third element. Plants that qualify for this system are awarded a guaranteed, cost-based feed-in tariff for a period of 20 years. They are also granted a connection and purchasing guarantee.

The first two elements of the German (and Continental European) electricity market have therefore been characterised by relatively short-dated supply contracts since the deregulation of the European electricity market. And in view of the increasing competition, the prices both on the energy-only market and the system service markets are under considerable pressure and are characterised by a sizeable price slump.

In addition to these central elements, the electricity market is, or rather was, also characterised by various other parameters which should not be overlooked in our analysis of the current market design and which cast serious doubt on the notion that the German electricity market is an energy-only market.

- Germany's Combined Heat and Power Act (KWKG) prescribes that a premium be paid to investors for a set period for their constructing CHP plants. From an economic perspective, these premiums can also be classed as capacity payments and amount to just under €60/kW per annum in the case of large plants.[11]
- Within the EU ETS, plant operators are awarded emission allowances for free in the second trading period, these being differentiated on the basis of the fuel type and the volume being based on historical production figures. This can likewise be interpreted as a capacity payment and can be estimated at around €37.50/kW for coal-fired power stations and approximately €18/kW for gas-fired plants.[12] Electricity generation plants will not receive any more free allowances as of the third trading period (2013–2020).

In the years subsequent to deregulation in 1998, the German electricity market was therefore shaped not only by income from the three above-mentioned market segments, but certainly also by significant implicit capacity payments from other energy and environmental policy instruments. This should not be overlooked when considering the historic developments of the German electricity market. Nor should the fact that the outlined returns from the EU ETS will cease as of 2013 and that the KWKG premium payments are restricted to new plants that are brought online by the end of 2020.

Nonetheless, the design of the German (and Continental European) electricity market developed in a concrete historical situation. The German electricity market was deregulated at a time of considerable surplus capacity which was invested in and predominantly refinanced at a time of regional monopolies, investment authorisations and cost pass-through guarantees, meaning only very limited or next to no capital charges had to be generated.

Subsequent to the transitional phase of deregulation of the German electricity market, the question that now arises is whether new investments are economically feasible. In other words, the question is whether sufficient contribution margins can be generated to adequately refinance investments with the parameters of an electricity market, the price levels of which are based on a comparatively homogeneous power plant fleet with a specific cost structure (low short-run marginal costs) that developed on the basis of specific historical conditions.

The debate regarding the ability of the energy-only market to generate the appropriate income is conducted on at least three levels:

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[11] This rough estimate is based on an annual capacity utilisation of 5,000 hours as an annuity over a period of 15 years with a rate of return of 8%.

[12] This rough estimate is based on the allocation arrangements for the second trading period (German Allocation Act 2012 [ZuG] and German Allocation Regulation 2012 [ZuV]) for an annual capacity utilisation of 5,000 hours in the basic period and a carbon certificate price of €10. The values change proportionate to any capacity utilisation divergences or other carbon prices.

- Firstly, there are the fundamental theoretical considerations.
- Secondly, the real conditions in the electricity markets can be taken into account.
- Thirdly, regulatory interventions need to be considered.
- And fourthly, there needs to be some consideration of the investors’ and the operators’ risks.

At the fundamental level, the question is whether the following basic assumptions for the model of complete competition can really be applied to the electricity market (Fritsch 2010):

- Consistent production technology
- No geographical preferences and transport costs
- An atomistic market structure with a large number of suppliers and demanders without market power
- Comprehensive and free information about all the market players
- Free market access and exit
- Unlimited divisibility of all the production factors and goods
- Infinite reaction speed without needing time for adaptation processes

This most certainly does not apply to the reality of the electricity market. While a number of energy market-specific analyses have described the potential of the energy-only market to refinance investments under ideal conditions, this is seriously called into question by analyses which are closer to reality.[13] There is a wide variety of reasons for this, relating to:

- On the one hand, the lack of elasticity in the demand, the market power in shortage situations, the need for surplus capacities to safeguard the necessary operating reserves, the considerable reaction periods and other factors intrinsic to the system, and
- On the other hand, regulatory risks (the acceptance of high-price phases, etc.)

The failure of the energy-only market, which can be expected with a very high degree of probability, is therefore attributable both to intrinsic factors and to regulatory interventions (or the corresponding expectations of the market players) and can in no way be made out to be purely a regulation failure.

[13] For a comprehensive and concise summary of the theoretical and the practice-oriented debate about the potential of the energy-only market to secure sufficient investments, please refer to Cramton/Ockenfels (2011), Süßenbacher (2011) and Süßenbacher et al. (2011). Further evidence is summarised in Matthes (2011).

An at least indicative piece of empirical evidence for this is the fact that, looking at the matter on an international scale, there are hardly any electricity markets in which a market design based exclusively on energy-only markets could have secured the level of investment needed to safeguard a high degree of security of supply in the long run.[14]

In addition, the fundamental problems of the energy-only market in securing the necessary investments have been further exacerbated by the not insignificant dynamic of very different parameters for the electricity market (cf. subsection 2.1.1):

- Developments in the fuel markets
- Developments in relation to the EU ETS
- The massive increases in costs in the markets for fossil fuel power plants
- The massive expansion of electricity generation on the basis of renewables

On the whole, having considered the entire array of the theoretical and empirical findings and taking all the intrinsic limitations, regulatory uncertainties, risk-averse investment behaviour and the aforementioned exacerbating factors into account, the predominant evidence is that the energy-only market is essentially hardly capable of safeguarding a satisfactory level of security of supply.[15]

In addition, the restructuring of the power supply system in favour of renewable energies also leads to a second challenge regarding a change in the design of the electricity market. At least on the basis of Continental Europe's conditions, an energy system dominated by renewables would be characterised by weather-dependent fluctuating power generation options. In this case, production is dependent above all on the meteorological conditions (sunshine, wind levels), is characterised by extremely low short-run marginal costs (the operating costs are very low for wind and solar power) and will make high storage capacities necessary, at least in the long run.

In a power supply system of this kind, it is almost impossible to envisage it being possible to refinance investments either solely or predominantly through an electricity market, the pricing of which is based on short-run marginal costs. Capacity payments are essential in exactly this kind of power supply system if it is to be financed on the

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[14] For comprehensive summaries of international situations, please refer to Süßenbacher (2011), Süßenbacher et al. (2011), DICE (2011a) and Frontier (2011). In particular, the analysis of Australia in DICE (2011a) should be noted, which explains that no capacity instruments were introduced to complement the energy-only market, but that there are important special conditions that have to be taken into account regarding ownership when investments in power plants are effected.

[15] In particular in light of the broad international discussion and the wide array of practical experience in relation to this topic, the opinion of Ecofys (2012a), which is based on a small number of analyses for Germany, that *"there are currently not enough indications that the energy-only market is unable to cope with the current challenges … Empirically speaking, there has so far been no evidence of a market failure in the medium term and nor does economic theory suggest that a failure of the energy-only market is to be expected"* would appear to not really hold water.

basis of market-level mechanisms. Ultimately, the financing of renewables in accordance with the current EEG can also be interpreted as capacity payments spread over 20 years and therefore at least implicitly constitutes a ‘capacity-only market’.

Although incorporating price signals from the current energy-only market into the support system for renewable energies increasingly appears to be necessary in the current situation in order to optimise investment and operations (Matthes 2012b), capacity payments will still have to be an important element of financing investments in renewable energies in the future.

The discussions regarding a market design which is fit for the future should therefore not only address the problems relating to securing residual load, but should specifically also take into account the challenges posed by the transformation of the power supply system (Matthes 2011).

A new market design should therefore harmonise the revenue components for renewable and conventional energy carriers, or at least make it a prospect. This calls for the development of a market with revenues for work, output and system services.

- An initial step in the direction of such a reform concept would be the introduction of output revenues determined in competition for conventional energies, which could complement the energy-only market.
- If, in a second step, this strategy were to be combined with a reform of the Renewable Energy Sources Act that also introduced different revenues for fixed capacity payments for renewable energies and, if applicable, also capacity payments differentiated according to technologies on the one hand and variable, electricity market-oriented unit prices on the other, the first step in the direction of market convergence will have been taken.
- The experience gathered from these two steps, which should be linked as much as possible due to the need for quick action in the conventional electricity market segment and with a view to achieving political acceptance of both of the reform plans, can lead to a gradual learning and development process that ultimately results in a common market for conventional and renewable energies.

A forward-looking reform of the electricity market design will therefore firstly have to comprise a strengthening of the market for electricity generation, which will continue to be crucial for operational and investment improvements, and will simultaneously also have to introduce capacity instruments and will, thirdly, have to implement a gradual convergence of the design of the markets for conventional and renewable energies. The second of these three challenges is the focus of the following analyses.

4 The objectives of a capacity mechanism

4.1 Objectives

The objectives of a new market mechanism have to take into account the target matrix of the energy transition. We essentially need to distinguish between two fundamental positions (LBD/Öko-Institut 2012).

- The first fundamental position defines nothing but the security of supply as the criterion for a capacity market.
- The second fundamental position defines the comprehensive catalogue of energy policy objectives relating to the energy transition as the basis for the capacity market to be created.

The first fundamental position is insufficient for a capacity mechanism. What's needed is an instrument that safeguards the success of the energy transition as a whole. It has to offer the long-term prospect of a conversion to low-emissions power generation and should also support the achievement of climate protection goals. In addition, there needs to be the prospect of integrating renewable energies. This is not possible if the focus is entirely on security of supply. Furthermore, the instrument needs to take the consumer's perspective into account. The proposal developed here is therefore founded on a catalogue of energy and climate policy objectives that go above and beyond safeguarding security of supply in a narrow sense.

The first five aspects of the WWF's list of questions regarding the design of capacity mechanisms (LBD/Öko-Institut 2012) in terms of the fundamental objectives of a capacity market model are specified as follows as the basis for defining the goals:

1. Should security of supply be the only criterion for the design of the capacity mechanism?

   The capacity mechanism should not be restricted to safeguarding security of supply. The energy transition can only be a success if market-based instruments that comply with the transition's target matrix are likewise provided. Taking into account the high level of expense involved in safeguarding consistency on the basis of a broad grouping of different and isolated approaches used to guarantee the various goals, an integrated target approach of this kind is both prudent and expedient.

2. Should climate protection be an explicit criterion of the capacity mechanism?

   A capacity mechanism should also take the climate policy targets into account. Capacity mechanisms should not lead to the accumulation of CO_2 and capital-intensive investment stocks which fix a certain level of emissions for extended periods or the depletion of which would only be possible with very high CO_2 prices or other major interventions. Providing incentives for high-emissions technologies should therefore be avoided as far as possible.

3. Should the mechanism also explicitly take consumer interests into account?

In order to guarantee acceptance of the instrument and of the energy transition in general in the long term too, the mechanism’s design should, as far as possible, avoid deadweight effects and should keep the costs for consumers as low as possible.

4. Should the mechanism explicitly pursue the aim of increasing or maintaining the level of competition?

   A new instrument for the procurement of secured capacities should maintain the levels of competition in the energy-only market and in the balancing power market. This is necessary in order to avoid costs caused indirectly for the consumer. After all, instruments that significantly reduce the level of competition at least indirectly result in an increase in costs in these markets.

5. Should the mechanism explicitly address the restructuring of the power supply system in favour of renewable energies?

   The restructuring of the power supply system in favour of renewable energies, thereby lowering carbon emissions, is the key energy policy objective of the energy transition. A new market instrument therefore needs to pursue this objective too. The integration of renewables into the market is frequently called for in the current political debate. The key question in this respect is whether this integration can be achieved successfully in the current market design. The divergent cost structures of renewable energies and of conventional energy carriers make integrating renewables into the current design of the market difficult, if not impossible. While the renewable energies are characterised by very high fixed costs and almost negligible marginal costs, the conventional energy carriers have comparatively low fixed costs and high, variable production costs. But the current market design only pays for the volumes of energy produced.

   A new market design should therefore harmonise the revenue components for renewable and conventional energy carriers, or at least make it a prospect. The appropriate steps should facilitate the gathering of experience and a learning process which culminates in a common market for conventional and renewable energies.

These specified goals constitute on the one hand the fundamental objectives for the basic structure of the capacity market model presented here, but also serve as a guideline for the more detailed design of the model. Particular in view of the complexity of the challenges (and objectives), the design should be developed in a manner which explicitly allows for learning processes and evidence-based adaptations and optimisations.

4.2 A brief appraisal of the existing proposals

Based on the current state of the informed debate in Germany, the fundamental necessity of incorporating capacity instruments into the current energy-only market and the scheduling of such mechanisms is (still) a contentious issue.[16] However, swayed by the current developments and the realistic opportunities to act at the nation state level, the majority of those involved in the debate are now discussing concrete models for instruments that take capacity management into account and which are competitive in nature.

Broadly speaking, the models currently being discussed can be divided into three groups, with a number of possible secondary alternatives in each case:

- Comprehensive capacity markets
- Strategic reserve
- Selective capacity instruments

Of these proposals, this report will briefly examine those for a comprehensive capacity market and for strategic reserve only, as these represent the extreme positions for capacity instrument proposals.[17]

The introduction of comprehensive capacity markets is the proposal which goes the furthest in terms of complementing the current market design. The proposal of this nature with the highest profile in the current German discussion was put forward by Cologne University's Institute of Energy Economics (EWI 2012). The key elements of this 'system of security of supply contracts' are as follows:

- The capacity volume needed in order to guarantee the targeted level of security of supply is defined with a lead time of five to seven years.
- With this lead time, an auction (a descending-clock auction) is held for this capacity volume, with the required involvement of all power plant capacities (otherwise they are to be decommissioned) and with the existing plants having to bid a price of zero in order to prevent the development of market power.

[16] For the arguments against the necessity of capacity instruments posited in the German debate, cf. Ecofys (2012b), Müsgens/Peek (2011), BTU/r2b (2012a), Consentec (2012a+b) and DICE (2011a+b). The necessity of capacity instruments in the long run in particular is stressed by Cramton/Ockenfels (2011) and EWI (2012), while BET (2011) and LBD (2011) argue that the short-term implementation of capacity mechanisms is imperative. Particularly important roles were played in the comprehensive debate of this issue in the UK above all by the analyses of Brattle (2009), Redpoint (2010) and NERA (2011).

[17] For a more in-depth comparison of the current proposals for Germany based on the WWF's list of questions (LBD/Öko-Institut 2012), please refer to the analysis of KEMA (2012). Agora (2012) offers a very concise presentation of various proposals.

- New plants which are successful in the auction receive a capacity payment equal to the price determined in the auction for an extended period (e.g. 15 years), while existing plants are awarded the appropriate annual price.
- The successful bidders are contractually obliged to have the appropriate capacities at their disposal.
- They grant the so-called coordinator of the security of supply market a call option which allows the coordinator to skim off price peaks above a predefined strike price.
- The successful bidders are not subject to any limitations whatsoever in terms of their participation in the energy-only and the balancing power markets.
- The cost of the capacity payments (if necessary, offset against the income from exercising the above-mentioned call options) is passed on to the end customers.
- There is strict adherence to the principle of technology neutrality and it should be possible to incorporate measures on the demand side.

This model, which is clearly based on the capacity markets in the north-east of the USA, offers a whole host of undisputed advantages in its ideal form (an efficient solution for the economy as a whole thanks to uniform pricing, a reduction in the incentives to exercise market power, a reduction in the price risks for the producers and suppliers, etc.), but is equally confronted with an array of disadvantages:

- The system entails a great deal of parametrisation. Going by all the previous experience (in particular the introduction of the EU ETS), the required comprehensive recording of capacity reserves is very time-consuming and there are numerous risks involved in the parametrisation of the total demand.
- Unless other arrangements are made, the total capacity reserves are allocated a standard price which is at least perspectively based on the capacity payments needed for new plants. This results in comparatively high costs on the consumer side (and substantial deadweight effects for a large proportion of the operators of existing power plants). Appropriate countermeasures (corridors for capacity payments to existing power plants, etc.) balance out at least some of the advantages.
- Realistically, market segmentation will be inevitable (duration of the capacity payments, different lead times, incorporation of demand-side measures, perhaps also price corridors for existing plants). The theoretical advantage of the standardised auction is therefore surrendered.
- The expenses involved in introducing a comprehensive capacity market model are considerable and this makes it very difficult to adjust or, if necessary, abolish the system. This is especially the case in the European context (insofar as the current institutional arrangements for security of supply do not change fundamentally).

- The system intentionally focuses solely on the question of security of supply.

Comprehensive capacity markets are designed for the long term. For their introduction, the EWI (2012) suggests a time frame in which additional power plant capacities can be realised by the beginning of the 2020s.

The instrument of strategic reserve is at the opposite end of the scale in terms of the capacity instruments discussed in Germany thus far. But there are (very) different proposals for such strategic reserve. Consentec (2012b) specifies a model which would effectively only be of use to existing plants, while r2b (2012b) presents the basic points of a proposal that focuses more on new plants. These models have the following common ground or differences:

- The total capacities needed in order to safeguard the desired level of security of supply and the capacity volume to be supported by the strategic reserve are defined with an as yet unspecified lead time (Consentec 2012b) or with a lead time of four years (r2b 2012b).
- An auction is held for this capacity volume (according to the descending-clock method), either for existing plants (Consentec 2012b) or new plants (r2b 2012b), with the plants accepting the compliance conditions (see below).
- The existing plants that are successful in the auction are awarded a capacity payment equal to the auction result for a period of two years (Consentec 2012b), while the duration of the capacity payments made to new plants has not yet been specified by r2b (2012b).
- The plant operators who secure capacity payments must keep their plants ready for operation/start-up in accordance with certain requirements or must comply with certain operation and time availability parameters.
- These plants may not participate in the energy-only or the balancing power markets – their capacities may only be sold at a predefined strike price in the event of shortages on the spot markets (day-ahead), with the sales being handled by the agency issuing the invitation to tender.
- The possibility of ‘no way back’ arrangements is considered (Consentec 2012b), which would prohibit plants that are awarded capacity payments from returning to the energy-only market.
- The cost of the capacity payments (if necessary, offset against the income from the usage caused by a shortage) is passed on to the end customers.
- If necessary, regional focuses for the appropriate auctions should be made possible (Consentec 2012b).

In its ideal form, the strategic reserve model results in the shortages in the energy-only market being maintained or increased and in price peaks continuing to exist. In its most unadulterated form (i.e. exclusively addressing existing plants or new-build power plants), there may be lower – but certainly not low – administrative expenses relating to the operation of the system. But upon closer examination, the model also has a number of disadvantages:

- Just like the comprehensive capacity market model, there is considerable parametrisation expense involved in the strategic reserve model too, above all in relation to the capacity volumes to be recorded. It is not merely the total capacities that have to be sufficiently robustly ascertained – so too do the capacities of the power plants to be maintained under threat of decommissioning and, if applicable, the necessary new-build capacities. In view of the removal of the relevant plants from the energy-only and the balancing power markets, there are considerable risks involved in the parametrisation of the maintained plant or new-build segment, and these are even greater if both segments are combined.
- In addition, regulatory risks can certainly not be ruled out if there is pressure in the political process to lower the price levels at which the power plants involved in supplying the strategic reserve are to be employed (in this respect, it is worth remembering the discussion of approving strategic reserve in the area of petroleum provisioning, which crops up again and again).
- Strategic reserve ultimately only serves its purpose if it can be assumed either that no major security of supply problems will arise for a long time or that, after a transitional period, the energy-only market will be in a position to incentivise maintenance of the necessary plant capacities or prudent new investments on its own. If this is not the case, the only consequence of the targeted increase in the price level in the energy-only market is higher wholesale prices and therefore transfers from the electricity consumers to the operators of the plants that remained in the energy-only market.
- Realistically speaking, incorporating demand-side measures into the strategic reserve instrument is neither consistent with the model, nor can this be implemented without significant problems.
- The system can only be reversible without causing major repercussions in the market if, firstly, the ‘no way back’ principle is systematically implemented and, secondly, the capacity volume recorded by the strategic reserve model remains relatively low.
- The system intentionally focuses solely on the question of security of supply and it is easy to forecast that it will, in the case of new-build plants being taken into account, only result in the construction of gas turbines.
- There are no important lessons that can be learned regarding the interaction of capacity instruments and the other electricity market segments or in relation to the auction processes for larger technology portfolios.

When the necessary procedures are realistically considered (capacity ascertainment and differentiation, drawing up robust auction processes, etc.), strategic reserve is equally not an option that will be available in the next one to two years to serve as an alternative to the regulatory arrangements for cold reserve needed at short notice, which are currently under discussion.

Discussion to date of the two versions of capacity instruments presented here (Consentec 2012a, Ecofys 2012a, EWI 2012) further corroborates the conclusion of similar discussions (in particular in the UK and the USA) that, rather than the ideal models themselves, the decisive determinants for the outcome of comparative analyses are actually various assumptions relating to concrete implementation and parametrisation options, appraisals of regulatory risks and their realistically anticipated impacts, different outlooks on efficiency evaluations (static versus dynamic efficiency) and the consideration of distribution effects.

Consideration also needs to be given to the fact that directly applying design elements or the experience of other countries or regions with their implemented capacity instruments also entails the challenge of sufficiently taking the concrete background of that particular electricity market into account. For example, the design of the comprehensive capacity markets in the north-east of the USA did not have to take into account the accelerated decarbonisation of the power supply system. The strategic reserve models in Scandinavia are a reflection of a relatively stable and not all that heterogeneous power plant fleet with very low operating costs (in particular hydroelectric power and nuclear energy) and are ultimately not confronted with the considerable dynamic that comes with the economic challenges of a power plant fleet with, in part, comparatively high operating costs and of various political interventions (the massive expansion of fluctuating renewable energies, the exit from nuclear energy, the enforcement of high emission standard for old plants, etc.).

The above considerations illustrate how probably neither of the ideal concepts is a suitable model for a robust and learning-oriented implementation process for capacity instruments. The following section therefore develops and specifies a proposal for an alternative capacity instrument which reflects the advantages of both models, avoids certain disadvantages, takes a wider spectrum of objectives into account and incorporates an array of suggestions from previous studies (LBD 2011, BET 2011, RAP 2012).

5. Proposal for a focused capacity market

5.1 Basic concept

The following framework for a new capacity instrument – the focused capacity market model – was developed in the light of the many different challenges associated with electricity market design, various aspects of the proposals which have shaped the discussion to date, and the explicit need for an intelligent process which is capable of learning.

- The discussion about capacity mechanisms in general and in particular the controversy surrounding the strategic reserve ultimately boil down to one key question: Can and will the energy-only market generate price signals which can successfully serve as a basis for making the investments needed to safeguard security of supply and maintaining the relevant existing conventional power plants? Against the backdrop of the theoretical discussion and real-world experiences, it is hard to imagine that it will. However, this possibility cannot ever be completely ruled out *ex ante* given the nature of the situation.
- The same applies to tapping the potential of demand-side measures. Here too, the capacity instrument is designed on the basis that erratic (very high) price peaks in the spot market segment of the energy-only markets only allow the existing load management potential to be tapped to a limited extent. This is particularly true of larger-scale investments or expenditure (for stand-alone projects or various measures pooled by aggregators) as opposed to organisational or low-intensity measures.
- Security of supply is the motivation behind modifying the electricity market design in the conventional segment, and its main objective. However, the longer-term prospects of capacity mechanisms when the power supply system is converted in favour of renewables should be a prime consideration. This applies to making the fleet of conventional power plants (which will play an important role in supporting electricity generation using renewables for at least another two decades) more flexible and more efficient[18] and ensuring they comply with ambitious emission standards. It is also an important point for competition-based financing and the market-oriented operation of renewable energies and storage systems to ensure security of supply in the future.

[18] Gearing the provisions for new generating capacity solely towards gas turbine power plants could prove extremely inefficient in the medium term if plants with comparatively low efficiency had to be operated for extended periods of time (e.g. to compensate for the varying amounts of wind power generated at different times of year). This is something which the strategic reserve concept for new plants, for example, implicitly does. Banning their use in the energy market would mean that the plants could not generate any contribution margins aside from capacity payments. The contribution margins from the energy-only market could tap into a more sustainable portfolio of plants, however (CHP or CCGT plants).

- In addition to safeguarding security of supply and contributing towards the overhaul of the power supply system, the restructuring of the electricity market should clearly aim to maintain the level of competition in the electricity market and limit costs for consumers.
- Given the wide-ranging challenges posed by the status quo, capacity mechanisms also need to be designed with developmental and learning-related requirements in mind. On one hand, this means creating an instrument capable of future learning – i.e. one which gradually adapts to future challenges at least to some extent. On the other hand, the mechanisms need to be designed in such a way that they can be adjusted and revised in the light of practical experiences and market developments.

Against this backdrop, this proposal for a focused capacity market rests on the following basic concept:

1. Segmentation of the capacity market: The focused capacity market should (initially) take into account the two segments of the power supply system which will face special challenges over the coming years: existing plants under threat of decommissioning and (necessary) new generating capacity. At the same time, the segmentation of the capacity market is a good starting point for differentiation (see below) and facilitates the adjustments which are bound to become necessary based on practical experience as time goes by. These adjustments may involve both the longer-term integration of the two segments and the temporary abandonment of one segment.
2. Product differentiation: It makes sense to differentiate between the products of the focused capacity market based on their lifespans (i.e. structurally adjusting the term of the resulting contracts between the relevant authority and the plant operators to the decision makers' economic timescale) in order to limit risk premiums and therefore the costs for the consumer. Furthermore, pre-qualification requirements should apply – especially for the new-build segment – which also bear the longer-term development of the power supply system in mind.
3. Extensive incorporation of the demand side: Demand-side measures (e.g. controllable load resources) should be incorporated as extensively and equally as possible into the focused capacity market as supply offers. By doing so, the demand side should be addressed via intelligent product differentiation within the respective market segments rather than by a separate market segment.
4. No restrictions on participation in the energy-only market and the balancing power market: Firstly, this should limit the cost to the consumer and maintain the level of competition on the electricity market. Secondly, the interaction between the capacity, energy-only and balancing power markets should address a wider portfolio of options. Thirdly, this interaction paves the way for system designers, operators and investors to learn lessons which are needed for the dynamic further development of the system.

This basic concept aims to establish a capacity market that is as simple and transparent as possible, but which is also capable of developing and therefore sustainable. There is no doubt that this generates a complicated dichotomy. However, the parametrisation questions which can ultimately be solved in a similar way for all capacity mechanisms provide a sufficiently robust way of dealing with this.

With a view to the other proposals for capacity mechanisms, this gives rise to the following observations:

- The focused capacity market model is based on the assumption that a capacity market is needed to permanently complement the energy-only market. In this context, the proposal for a focused capacity market seems to be the obvious solution to the task of developing a model for a comprehensive capacity market.
- This model is also linked to the concept of a comprehensive capacity market as regards the incorporation of demand-side measures. By contrast, the strategic reserve concept primarily sets out to address the demand side via the energy-only market. Although it allows for demand-side measures to be incorporated in principle, this is not really consistent with a view to the overall concept of a strategic reserve.
- As regards the idea of contributing towards restructuring the power system, the concept differs fundamentally from both the model of a comprehensive capacity market and the proposals for a strategic reserve. Both of these share the prime objective of safeguarding security of supply but do not allow for the power supply system to be overhauled. This proposal is more closely aligned with the concept of capability markets in this regard (RAP 2012).
- With reference to the level of competition, the focused capacity market is more strongly linked to comprehensive capacity markets. In terms of limiting the cost to the consumer, the focused capacity market concept is similar to the strategic reserve when it comes to the cost of capacity payments. As regards the net cost taking pricing effects in the energy-only market into account, the concept is more closely linked to the model of a comprehensive capacity market, however.
- On the whole, previous proposals for capacity mechanisms have not sufficiently taken the learning and sustainability aspect of the focused capacity market into account.

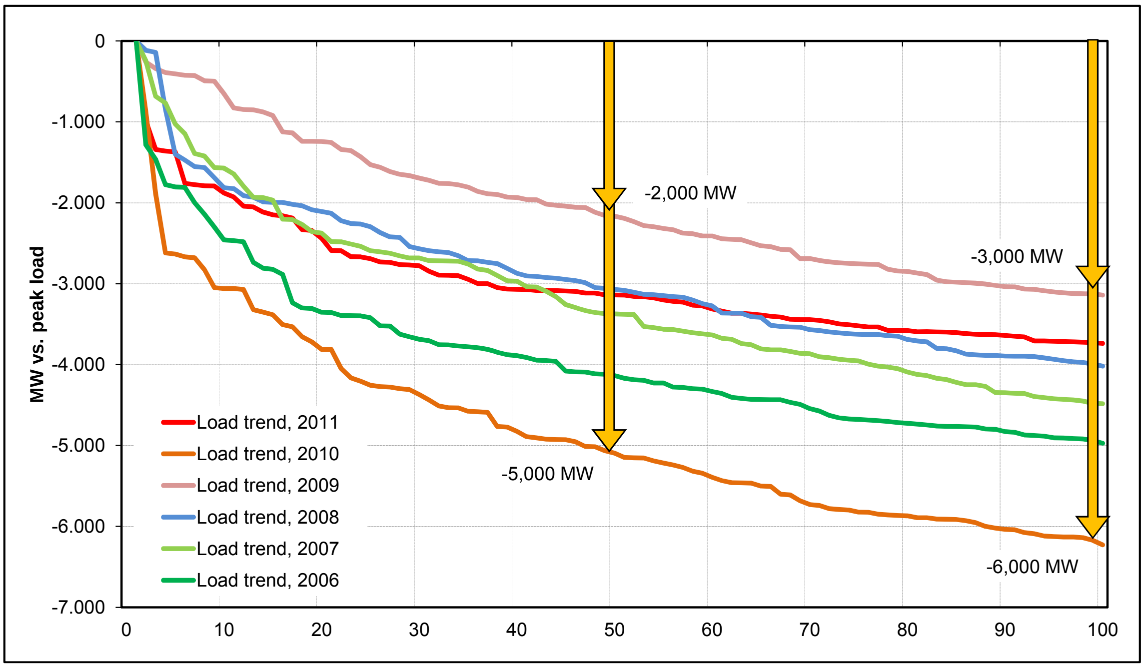
The following sections provide more specific details about the individual elements of the focused capacity market.

5.2 Defining the market segments

5.2.1 Existing power plants under threat of decommissioning

The margin situation for power plants allows indicative assessments to be made regarding the power plants under threat of decommissioning. Figure 8 illustrates how different power plants' cumulative contribution margins have developed in relation to their annual capacity utilisation. The spot market prices observed for 2011 are used as a basis. The figures only take power plant options into account which can be assumed to have insufficient coverage of their fixed costs. For this reason, lignite-fired power plants are not included in the analysis because they are unlikely to face the problem of fixed cost coverage given the level of electricity prices combined with very affordable lignite.

Figure 8 The development in contribution margins from the spot market for various power plant options in relation to capacity utilisation, 2011

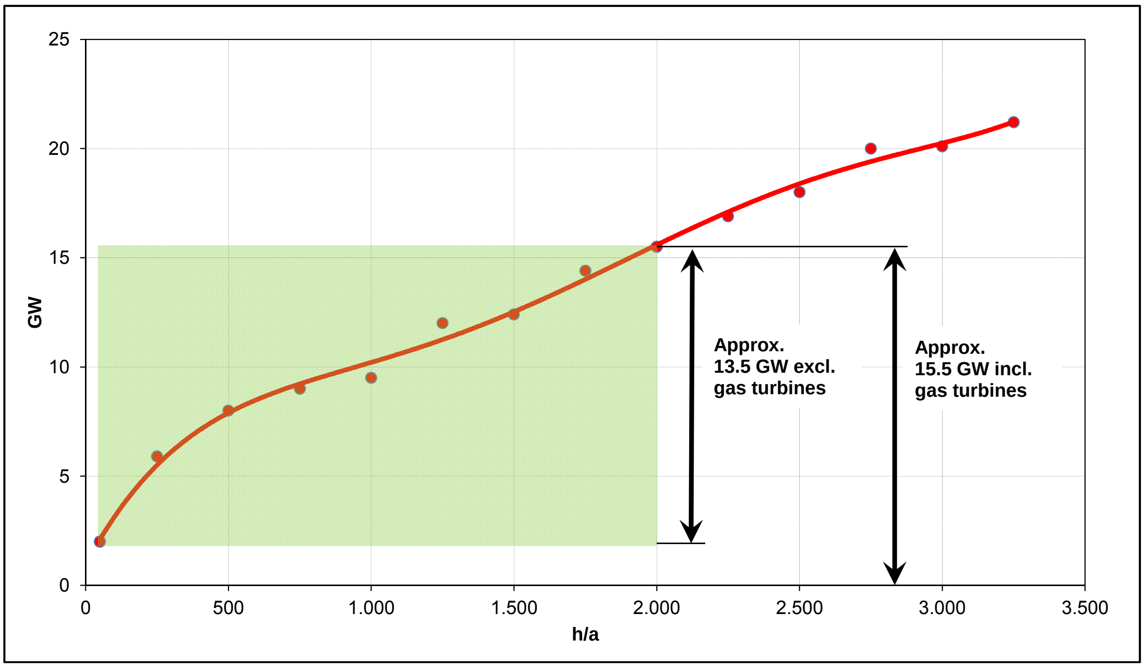


Source: EEX, Öko-Institut calculations

The diagram shows that higher short-term marginal costs (fuel and CO_2 costs) result in lower annual capacity utilisation, meaning that the plants generate lower contributions towards the coverage of fixed operating costs. Older (larger) coal-fired power stations with marginal costs of approx. €50/MWh which operated for more than 1,500 hours were therefore able to cover the lower end of their fixed costs in 2011. The same applied to new gas-fired power stations. Excluding revenue from the allowances awarded free of charge as part of the EU ETS scheme, small coal-fired power stations and new gas-fired power stations fell a long way short of covering their fixed operating costs in 2011. This was also true of fixed cost coverage for gas turbines, whose short-term marginal costs (fuel and CO_2) are at the upper end of the range depicted.

This assessment of the situation in 2011 enables us to calculate an indicative figure for annual capacity utilisation below which the power plant options examined here struggle to cover their fixed costs. An assessment of the various options as a whole puts this figure at approximately 2,000 operating hours. It should be remembered that this figure is purely indicative because the concrete economic risks depend to a large extent on local factors and the associated fixed costs.

Figure 9 Output of fossil-fuel power plants in relation to their annual capacity utilisation



Source: Öko-Institut calculations

Figure 9 shows the scale of the various capacity segments in relation to annual capacity utilisation, using an electricity market model for 2015 as an example. The diagram shows that a number of power plants with an output of approx. 15.5 GW are being operated at capacity utilisation rates of less than 2,000 hours per annum. Gas turbines – i.e. plants traditionally geared towards peak-load operations – account for approx. 2,000 MW of this. Corresponding evaluations of historic data (capacity utilisation in relation to vertical grid load) result in a slightly lower figure. The segment amounts to some 13 GW in this case. Nevertheless, 13 to 15.5 GW is a robust range for existing power plants which are operating on the market but are under threat of decommissioning.

There is more to the issue of decommissioning than these active power plants. The necessary back-up generating capacity must also be considered as the energy produced by these power stations is only in demand on very rare occasions when the security of supply is at risk. ENTSO-E currently estimates that this power plant segment accounts for 5% of load requirements, resulting in a figure of around 4 GW for Germany.

This means we can assume that power stations with an output of 17 to 20 GW are under threat of decommissioning over the next few years. However, it should be remembered that this decommissioning will not happen suddenly; it will primarily occur when large-scale inspections take place, revealing necessary maintenance investments, and when there are concrete opportunities to minimise the cost of decommissioning (e.g. as regards human resources).

Old coal-fired power stations, CCGT plants and gas turbines are currently typically operated for less than 2,000 hours a year. Power plants in this demand segment will have to be started up once or twice a day (in the morning before the feed-in from photovoltaic systems peaks and in the evening when photovoltaic systems cease to generate power). This will pose economic problems for many existing power plants. As time goes by, they will increasingly face technical problems too. This scenario also presents specific challenges for modern CCGT plants, which will be particularly important in the medium and long term in the context of the energy transition and will have to play a special role in the future. That is because they are suitable for higher capacity utilisation, which will prove important – especially in the light of seasonal differences in the amount of energy generated using wind power. Modern CCGT plants also emit approximately one third less CO_2 and use chemical storage media around one third more efficiently than gas turbines. However, they are at serious risk of decommissioning in the current energy industry environment.

Back-up capacity is currently supplied by old steam power plants which use natural gas and by oil and gas-fired gas turbines. These plants have already virtually exhausted their potential for generating revenue (cf. section 2.1). As new coal-fired power stations go online in 2013 and 2014, they will squeeze out existing power plants to an even greater extent and further increase the pressure to decommission them. As gas turbines and steam power plants which use natural gas are already virtually obsolete, these plants no longer have any economic prospects and will be decommissioned in the near future with no further support.[19]

As the use of renewable energies is increasingly ramped up, this market segment will steadily grow because more and more power plants will fall short of 2,000 operating hours as they are squeezed out of the market. Using annual capacity utilisation to define the existing capacity segment would serve as a dynamic and compensatory means of tightening the parameters for existing facilities. It would act as a dynamic integration mechanism.

In summary, it can be said that the segment of power plants under threat of decommissioning can be defined relatively robustly using annual capacity utilisation. Based on preliminary estimates which suggest 2,000 operating hours per annum as a pre-qualification requirement for existing power plants to participate in the focused

[19] One example of this is EON's announcement that it will decommission three natural gas-fired blocks in Irsching, Staudinger and Franken.

capacity market, the segment in Germany would have a total output of approx. 17 to 20 GW. The authors would like to state explicitly that the estimate presented here is purely indicative. During implementation of the focused capacity market, a transparent process must be used to define the relevant concrete segment criteria. This process should comprise far-reaching consultations and sensitivity analyses (cf. subsection 0).

Considering the power plant fleet which is relevant to this segment and the need to safeguard this fleet in the short term, no additional (technical) pre-qualification requirements should be stipulated in the initial phase. However, at a later date – i.e. beyond 2020 – it could be examined whether it might be prudent and expedient to introduce flexibility requirements or emission standards for this segment of the focused capacity market too.

5.2.2 New-build power plants

Depending on developments in the power plant fleet and anticipated trends in load requirements, it will become necessary to invest heavily in new-build power plants over the next two decades. Given the foreseeable parameters for the energy industry, we can assume that these will largely be plants which are fundamentally cost-effective even at low rates of annual capacity utilisation. New generating capacity will also tend to have a low level of capital cost intensity. Against this backdrop, the majority of the new conventional power stations which are built will have to be fired by natural gas.

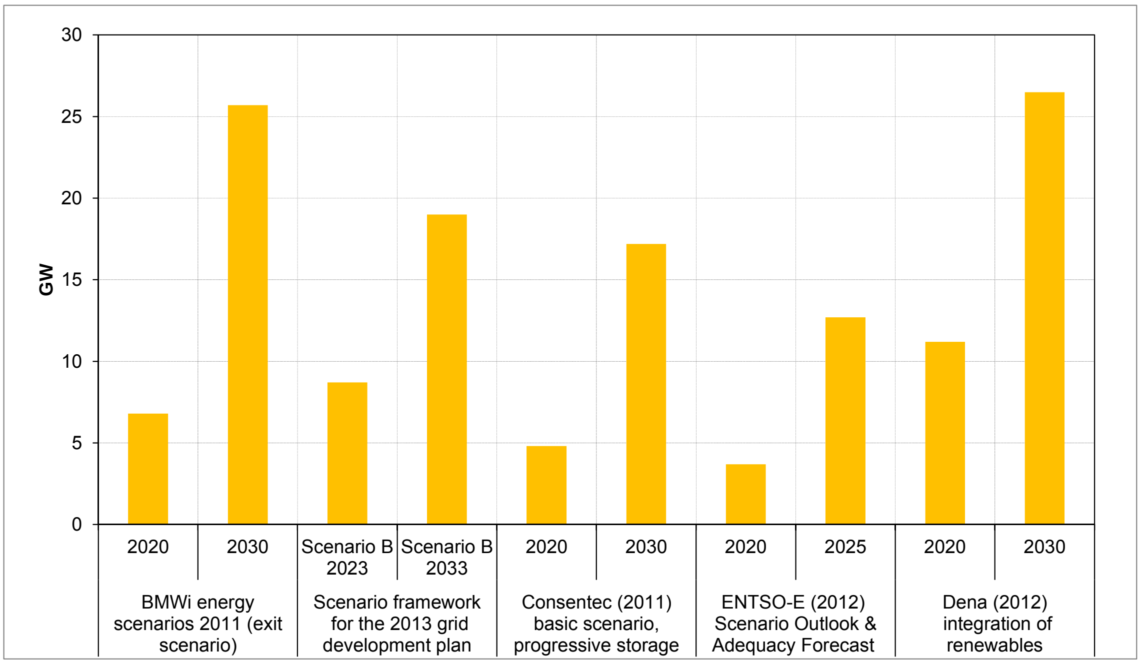
These quality considerations are confirmed by the results of quantitative model analyses.[20] Analyses of the scenario framework for the 2013 grid development plan (ÜNB 2012a) anticipate that new (as yet unapproved) natural gas-fired power plants with an aggregate output of 8 GW will be built by 2023, with a further 18 GW being added by 2033.[21] The comparison in Figure 10 makes it clear that other modelling

[20] The modelling projects analysed more closely here were chosen based on whether new generating capacity was explicitly mentioned and/or was relatively easy to derive from the data frameworks.

[21] As regards the modelling projects examined here, it is difficult to identify precisely which plants are defined as under construction in the studies in question. However, a limited number of larger-scale new-build projects (> 400 MW) for natural gas-fired power stations have been approved for construction in Germany. In 2011, planning permission was awarded for CCGT power plants in Bremen (445 MW) and Hürth (430 MW). Supported by Germany's amended Combined Heat and Power Act (KWKG), permission was also granted for new-builds in Düsseldorf (535 MW) and Cologne (450 to 600 MW) in 2012. In the scenario framework for the 2013 grid development plan, the projects in Hürth, Düsseldorf and Cologne were classified as being in the planning stage. The new generating capacity to be built as shown in Figure 10 was reduced by 1,500 MW accordingly. The scenario framework for the 2013 grid development plan provides the most clearly documented set of data to date on the need to construct new fossil-fuel power plants. In the interests of producing a conservative estimate, the need for new-build natural gas-fired power plants was reduced by 2 GW in all the other studies examined, so as to eliminate the possibility of counting the above-mentioned new-build projects twice.

projects have also identified new-build requirements on a similar scale, although the figures differ widely in some cases.[22]

Figure 10 The need for additional new natural gas-fired power plants (in addition to the capacity currently under construction) by 2020 and 2030 according to current modelling projects



Source: EWI/Prognos/GWS (2011), ÜNB (2012), Consentec/IAEW (2011), ENTSO-E (2012), Dena (2012), Öko-Institut calculations

All of this demonstrates a general consensus that there is a concrete need for new (natural gas-fired) power plants. However, certain differences of opinion exist as to the precise capacity needed and the relevant timescale. These probably result primarily from the above-mentioned factors, i.e. load requirements and developments in the existing power plant fleet.

Overall, the range of figures arising from the modelling projects shown above allows us to assume that new gas-fired generating capacity of approx. 5,000 MW will be needed by 2020, with an additional 15 to 20 GW at least needed between 2020 and 2030. Once again, it should be noted that this estimate is merely indicative and a comprehensive evaluation is needed in the course of the parametrisation and implementation of the focused capacity market.

22 However, it should also be noted that the raw data is less well documented in the other studies which were examined. As a rule, they do not differentiate between new-builds and decommissioned plants. Dena (2012) also quotes an incomprehensible output of just 14 GW from natural gas-fired power plants in 2010, which results in a particularly large number of new-builds on paper.

Assuming that the first auctions for new generating capacity are held in 2015 and a lead time of four years is needed, the first power stations could go online in 2019. This means there are some ten auction dates in total for plants scheduled to go live by the beginning of 2030. This would mean an annual auction volume of 1,000 to 2,000 MW, depending on the precise requirements identified. If capacity of 2,000 MW was auctioned per annum in 2015, 2016 and 2017, up to 6,000 MW of capacity could go online in total in 2019, 2020 and 2021 in order to safeguard the exit from nuclear power.

Substantial load gradients arise in any electricity system with a large proportion of renewable energies focusing on wind and solar power. Flexible power generation options are needed for the period to 2030 which are capable of meeting the required load even with a residual load change of 30 to 45 GW within the space of a few hours (Consentec/IAEW 2011). The expansion of photovoltaics alone will result in load gradients of up to 12 GW an hour in the next decade (VDE 2012a). If a low load level coincides with a high feed-in of renewable energies, there will be times even in this decade when renewables will be able to cater for Germany's entire electricity requirements (e.g. on a Sunday in summer with low load when the feed-in from photovoltaic systems is high or on a low-load night at the weekend when a large amount of energy is fed in by wind power).

On one hand, this means that considerable generating capacity is needed which can realise load gradients on this kind. On the other hand, steps should be taken to prevent them from creating a block of capacity which has a negative technical or economic impact on the power supply system as 'must run' capacity. In this context, generating capacity of this kind is also problematic. Although it can achieve very good load-cycle rates at high levels of capacity utilisation, it does not have this flexibility below certain degrees of capacity utilisation. Power stations of this kind therefore ultimately represent 'must run' capacity.

Against this backdrop, it is prudent to stipulate certain minimum levels of flexibility as a pre-qualification requirement for the new-build segment of the focused capacity market. The ability to operate quickly following a cold start is a useful criterion in this context. This means that the plants can be shut down completely when sufficient power is being generated using renewables and the residual load decreases sharply. It must also be possible to start these plants up again quickly when the supply of renewable energies falls and the residual load increases (quickly).[23]

As regards the pre-qualification criterion of flexibility, the following points should be considered:

- It is unwise to pursue flexibility criteria which prioritise a high load changing rate at a partial load range of 50% to 100% of net output or a low part-load

[23] This situation typically arises when the feed-in from photovoltaic systems falls away in the afternoon.

capability. Traditional base-load power stations typically conform to these parameters.

- Flexibility following a cold start is a good alternative in view of these considerations. Pre-qualification requirements could stipulate that plants must be able to reach nominal output within one hour following a cold start.[24]
- With the aim of preventing new ‘must run’ capacities in the partial load range too, plants should have a minimum load range corresponding to a maximum of 20% of the nominal load.

Above and beyond the flexibility requirements, it is also sensible to stipulate minimum criteria for specific greenhouse gas emissions. This serves to safeguard the long-term suitability of the power plants which are constructed within the capacity market framework and operated for extended periods of time. The following aspects should be taken into account when specifying such pre-qualification requirements:

1. Steps should be taken to prevent the build-up of very CO_2-intensive capital stock.
2. However, the pre-qualification requirements should take the utilisation ratios into account which can be achieved with power plants that are operated at high load-cycle rates.
3. The technology portfolio which is available to meet the residual load in a highly flexible fashion should be carefully considered.
4. The pre-qualification requirements should also enable bivalent plant concepts (fired by natural gas/fuel oil) which could prove useful to safeguard security of supply, especially if the availability of natural gas becomes limited (e.g. as a result of capacity restrictions in the natural gas network).

Against this backdrop, emissions of 600 g CO_2/kWh could be stipulated as a pre-qualification requirement for the new-build segment of the focused capacity market. Gas turbines with a bivalent firing system (50% light fuel oil, 50% natural gas) and an energy conversion efficiency of 40% generate specific emissions of 585 g CO_2/kWh.

In all probability, the combined effect of the tendering procedure (primarily promotes investments with low capital intensity), fuel costs (natural gas costs less than fuel oil, so plants fired by fuel oil tend to be operated for shorter periods of time) and the pre-qualification requirements concerning flexibility and maximum emissions will largely prevent the version of a capacity market described here from building up CO_2-intensive capital stock which is counter-productive in the long run.

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[24] The utility company Stadtwerke Düsseldorf published key data for its natural gas-fired CCGT new-build project on 02/07/2012. The planned gas turbine is very flexible and can supply 350 MW of power within ten minutes thanks to quick-start technology. This means it can achieve more than 50% of its nominal output (595 MW) within the space of ten minutes. http://www.swd-ag.de/unternehmen/erzeugungsanlagen/lausward.php.

In addition to this, regional restrictions could be imposed for new-build tenders – especially during the initial phase – to ensure that the new-build segment is primarily geared towards constructing generating capacity in regions with supply problems caused by grid bottlenecks on the power generation side. This is particularly important in the first few years and/or during the phase in which grid bottlenecks will pose a considerable challenge.

Pre-qualification requirements may be imposed under European law. In fact, Article 8(1) of the Directive 2009/72/EC dated 13 July 2009 (the Electricity Directive) explicitly allows for such criteria. Article 8(1) of the Electricity Directive stipulates that Member States shall ensure the possibility, in the interests of security of supply, of providing for new capacity or energy efficiency/demand-side management measures through a tendering procedure or any procedure equivalent in terms of transparency and non-discrimination, on the basis of published criteria. As per Article 8(3)(3) sentence 2 of the Electricity Directive, these criteria may also relate to the aspects referred to in Article 7(2) of the Directive. Article 7(2)(c) of the Electricity Directive lists environmental protection and Article 7(2)(k) of the Electricity Directive cites the reduction of CO_2 emissions. This means that specific requirements regarding permissible greenhouse gas emissions can be imposed during the tendering process. According to Article 7(2)(j) of the Electricity Directive, generating capacity can also be required to have sufficient flexibility to compensate for volatile feed-ins from renewable sources. This means that the ability of plants to operate quickly following a cold start is an equally valid criterion for new-builds.

To ensure that only new power plants which are guaranteed to be built participate in tenders, the plant operator should produce evidence that it is highly probable the new-build project will go ahead. Operators could be required to produce all of the following:

- A confirmed right to use the land which the new power plant is to be built on.
- Approval under public law – i.e. outline planning permission or (partial) approval as per the German Clean Air Act (BImSchG), stating that the project has been fundamentally approved by the planning and pollution control authorities.
- Supply contracts pertaining to key plant components or relevant confirmed options to purchase such parts.

However, a confirmed source of funding cannot be stipulated as a requirement for participating in tenders because operators can only secure financing once they have been awarded a contract during the tendering process.

In this connection, steps must also be taken to clarify how a legal distinction could be made between old and new plants on the date capacity market regulation comes into effect.

This distinction should consider the extent to which capacity payments could act as an incentive for the plant operator. There is little point involving operators who have already made a final investment decision in the tendering process for new plants.

However, it is difficult to prove at what point the final investment decision was made. It would be possible to use the plant's technical operational readiness as a basis – including the granting of approvals under public law – drawing on the definition in Section 3(5) of the German Renewable Energy Sources Act. Technical operational readiness requires a plant to be completed, i.e. fundamentally capable of generating electricity on a permanent basis and able to do so in reality (Oschmann in: Danner/Theobald, Energy, 74th amendment 2012, Section 3 note 79). By contrast, plant operators can postpone the point at which a plant goes online so that it can be recognised as a new plant. This means that the go-live date is not a suitable criterion.

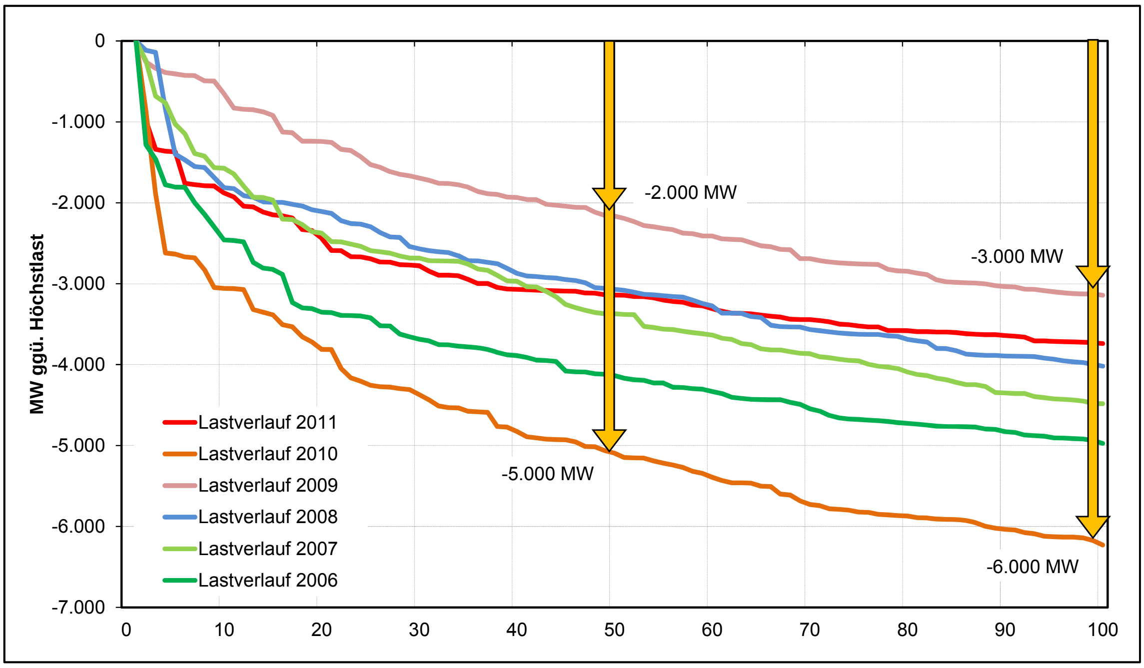
5.2.3 Demand-side measures

Germany and Europe as a whole fall a long way short of tapping the contribution that controllable loads can make towards safeguarding security of supply. Major industrial consumers (ThyssenKrupp, Trimet, etc.) and various aggregators are already active on the reserve markets. However, there are several reasons why the segment of controllable loads is not being sufficiently utilised outside of the balancing power market as a means of making the demand for electricity more flexible. It is evident that the price signals observed from the energy-only market to date do not currently provide a sufficient foundation for business models which could be used to improve the way the potential of controllable loads is tapped. This can be explained by various imponderables, the aversion of many large and medium-scale consumers to risk and/or their hedging requirements, and the lack of power measurement and invoicing among many medium-scale and small consumers. Given that such a wide range of barriers are preventing potential demand-side curbs from being utilised, there is no indication that this situation could improve while today's energy-only market is in place (SEDC 2011).

They offer substantial potential, however: both individual sector analyses (FfE 2010, Paulus/Borggrefe 2011, SEDC 2011, VDE 2012b) and experience from other markets (PJM 2011) indicate that a significant portion of load and flexibility requirements can be met by controlling loads. This is particularly true when it comes to using aggregators to tap controllable load resources and thereby enabling relevant measures to be applied to the segment of small and medium-scale consumers as well.

Calculations suggest that Germany has potential controllable loads of 1,000 to 3,000 MW over the coming years and at least 3,000 to 5,000 MW in the medium term. However, this potential relies heavily on the length of time for which load requirements are reduced and/or shifted to off-peak periods (FfE 2010).

Figure 11 Difference between actual load and peak load for the 100 highest load hours in Germany, 2006 to 2011



Source: ENTSO-E, Öko-Institut calculations

Figure 11 clearly illustrates the scale of the issue. With the exception of the crisis-hit year 2009[25], the German power supply system's peak load could have been reduced by 3,000 to 5,000 MW if loads had been shifted to off-peak periods for a total of 50 hours. If loads had been shifted to off-peak periods for a total of 100 hours, the peak load could have been reduced by 4,000 to 6,000 MW.

Creating transparent, calculable demand for controllable load resources is considered to be a crucial step towards tapping the existing potential, especially from the point of view of the relevant (potential) market players. Integrating these resources into capacity markets is seen as a particularly promising strategy, especially given international experience in this area (SEDC 2011).

Integrating controllable loads into the capacity market instead of creating special instruments to tap their potential is a logical step. This is especially true considering that, firstly, reducing demand-side load and/or shifting it to off-peak periods can make a substantial contribution towards boosting liquidity in the capacity market and can thereby significantly improve its functionality (more intensive learning process, reduction of market power, etc.) Secondly, incorporating controllable loads into the capacity market – either directly or via aggregators – is relatively straightforward because the load reduction for limited periods of time can be accurately defined and

25 In 2009, the peak load was several thousand megawatts lower than the benchmark figures for the other years shown (according to data supplied by the European Network of Transmission System Operators for Electricity – ENTSO-E).

evidenced without the need for complex methodology. The challenges are greater for the (lead time) periods during which controllable load resources can fulfil binding obligations. The planning timescales used as standard in the industry – approximately three to six years – will have to be used as a basis in this context. This means that it will be possible to offer controllable load resources in the focused capacity market segment if there is demand for products with terms up to this maximum duration. From this point of view, it makes sense to integrate them into the segment of existing power plants, where similar time-frames are feasible (cf. subsection 0).

As well as integrating controllable loads into the capacity market, it may be possible to incorporate energy efficiency programmes. However, international experience in this field (PJM 2011) shows that demonstrating associated load effects and – above all – their additionality poses a complex methodological challenge. For this reason, it is not recommended that programmes of this kind be integrated into the initial phase of the capacity market launch. The basis for incorporating energy-efficiency measures or programmes would have to be developed over time if applicable.

There is nothing in European law that goes against this approach of initially only integrating controllable loads into the capacity market and excluding energy efficiency measures from the capacity market.

Article 8(1) of the Electricity Directive stipulates that Member States shall ensure the possibility, in the interests of security of supply, of providing for new capacity or energy/demand-side management measures through a tendering procedure *or* any procedure equivalent in terms of transparency and non-discrimination, on the basis of published criteria. In other words, Article 8(1) of the Electricity Directive allows Member States to choose whether they issue tenders for new capacity or energy/demand-side management measures.

Article 2(29) of the Electricity Directive defines energy efficiency and demand-side management as “a global or integrated approach aimed at influencing the amount and timing of electricity consumption in order to reduce primary energy consumption and peak loads by giving precedence to investments in energy efficiency measures, or other measures, such as interruptible supply contracts, over investments to increase generation capacity, if the former are the most effective and economical option, taking into account the positive environmental impact of reduced energy consumption and the security of supply and distribution cost aspects related to it”.

This could give energy efficiency and demand-side management measures precedence over investments in boosting generating capacity – i.e. the construction of power plants and investments in existing power stations – which would result in an obligation to incorporate energy efficiency measures into the capacity market.

However, according to Article 2(29) of the Electricity Directive, precedence is given to “investments in energy efficiency measures, *or* other measures, such as interruptible supply contracts”. This means that Member States do not need to integrate both models into the capacity market. Instead, they can choose to incorporate one or both of these approaches into the tendering procedure as per Article 8(1) of the Electricity

Directive. That the focused capacity market model initially only incorporates controllable loads – which qualify as “other measures, such as interruptible supply contracts” as per Article 2(29) of the Electricity Directive – is therefore not problematic, meaning that energy efficiency measures can be integrated at a later date.

Article 2(29) of the Electricity Directive states that “other measures” of this kind fundamentally take precedence over the creation of new capacity if they are the most effective and economical option, taking into account the positive environmental impact of reduced energy consumption and the security of supply and distribution cost aspects related to it. However, this concept involves inviting tenders for demand-side management measures at the same time as creating additional capacity using both existing and new plants. For this to be permissible, demand-side management alone must be deemed not to be the most effective and economical option, taking into account the positive environmental impact of reduced energy consumption and the security of supply and distribution cost aspects related to it.

This verdict can only be reached by national legislators, who have a certain amount of scope in this context (European Court of Justice, verdict dated 25/2/2010, case no.: C-562/08, NVwZ 2010, 629, 630 – *Müller Fleisch-GmbH/Land Baden-Württemberg*). The tendering procedure in itself ensures that the most effective and economical option – demand response via controllable loads or the creation of new capacity – is successful. This format promotes whichever option achieves the most substantial reduction in capacity usage or creation of capacity at the lowest cost.

5.3 Capacity market products

The primary objective of the focused capacity market proposed here is to safeguard security of supply by guaranteeing:

- A sufficient segment of existing fossil-fuel power plants
- The construction of new power plants as necessary, and/or
- The provision of equivalent capacity by means of appropriate controllable load resources

This should be done in such a way that the capacity instrument’s secondary aims (affordability for consumers, contribution towards transforming the power supply system, etc.) can also be fulfilled to the greatest possible extent. These various dimensions of the capacity market’s primary and secondary objectives inevitably have an effect on the specification of the products traded on the capacity market.

The capacity market’s goal of competitively triggering payment flows for the provision of generating capacity and/or equivalent demand-side measures automatically results in the first specification for the capacity market product, i.e. making payments for the provision of a certain capacity (during a particular period of time).

First of all, it is necessary to specify how long these payments will be made for and how the relevant capacity should made available in return.

If the capacity (and possibly also the capacity payments) is only ever to be provided for a very short period of time, this will lead to substantial risk premiums, especially in the new-build segment. It therefore seems prudent for the term of the product to be geared towards the economic lives of representative measures taken to provide capacity in the relevant segment. This translates into shorter terms for existing power stations and longer terms for new-builds.

The following observations and considerations are also based on the assumption that it makes sense to spread out capacity payments throughout the period for which the capacity is to be provided[26].

Against this backdrop, the following factors should be considered when defining the products traded on the focused capacity market:

- It is probable that capacity payments would have to be made over a longer period of time (ten to 15 years) to provide a sufficient basis for investments in new power plants (without substantial risk premiums). The length of time over which capacity payments are made is a compromise between investors' interests and consumers'. While investors generally prefer higher capacity payments during the start-up phase, it is better for consumers if payments are spread out over a longer period of time.
- In all likelihood, longer-term capacity payments make little sense for existing power plants (technical risks associated with old facilities and limited remaining useful lives) and rule out most controllable load resources (especially as regards the relevant facilities' lives and/or industrial planning timescales). They would also trigger substantial risk premiums.
- Very short-term capacity payments (e.g. one year) would go against the aim of safeguarding the existing fleet in the case of old plants in need of upgrading or time-consuming staffing adjustments. They would also make it much more difficult to offer controllable load resources requiring investment and prompt considerable risk premiums. Capacity payments and the provision of capacity over a four-year period could make many of these problems less severe.

The following time-frames therefore seem prudent for capacity payments:

- Capacity payments and capacity provision for a 15-year period for facilities which participate in the new-build auction
- Capacity payments and capacity provision for a four-year period for facilities and/or controllable load resources which participate in the auction for existing

[26] In principle, it would also be possible to consider models where capacity payments and the provision of capacity are based on different timescales. However, this would require substantially greater regulation in the field of compliance and is therefore not to be recommended.

plants and which require (smaller-scale) investment and/or other commitments (staffing adjustments, etc.)

- Capacity payments and capacity provision for a one-year period for facilities and/or controllable load resources which participate in the auction for existing plants and for which the above-mentioned restrictions are irrelevant

While the first specification applies exclusively to the tendering process in the new-build segment, it makes sense to invite tenders from existing capacity for a portfolio of products. For example:

- Offering the four-year product for 75% of the sought capacity
- Offering the one-year product for 25% of the sought capacity

This would mean that auctions for existing capacity would be held every four years for the former product and every year for the latter. This would guarantee a certain minimum frequency and liquidity for the auctions for existing capacity and demand management.

Treating old and new facilities differently in this way is permitted under the Electricity Directive. The definition of the tendering procedure in Article 2(24) of the Electricity Directive covers tendering for capacity from new or existing power plants. By contrast, Article 8(1) of the Electricity Directive only regulates tendering for new capacity. Pursuant to Article 8(4) of the Electricity Directive, consideration must also be given to electricity supply offers with long-term guarantees from existing generating units, provided that additional requirements can be met in this way. Additional requirements can only be expected to be met in this way if the relevant plant was due to be decommissioned and the tendering process prevented this from happening. This is because all other existing power stations are already taken into account when calculating the available capacity and cannot therefore be considered again in the context of reducing capacity requirements. A reduction in operating hours to less than 2,000 per annum – from which point plants are under threat of decommissioning because they are unable to generate contribution margins – is therefore a permissible classification criterion under the Electricity Directive.

Differentiating between existing and new facilities based on the duration of the tendered capacity – one, four or ten (15) years – is also justified. Existing power plants have often already been depreciated in full and do not therefore rely on long-term income from capacity payments. The four-year tender period distinguishes between operators of old plants who have made small-scale investments and operators of old facilities who have made no investments. This distinction is permissible because the latter are not subject to any investment risk.

In return for the capacity payment, operators provide capacity and/or equivalent controllable load resources. However, in view of the forthcoming restructuring of the power supply system, it is prudent not to gear demand solely towards the provision of capacity. Instead, this capacity should be further qualified in line with future requirements:

- The reasons for this are obvious as regards the flexibility of new facilities financed within the framework of the capacity market, which will form part of the system long term. The ability to operate quickly following a cold start, high load gradients and possibly also energy conversion efficiency at partial load will play an important role here. To guarantee the power system's dynamic efficiency, associated requirements could be stipulated as pre-qualification criteria for participation in the new-build auction (cf. subsection 0).
- Given that grid bottlenecks will continue to occur in Germany for the foreseeable future, it would also be prudent to restrict the new-build auction to certain network areas, at least during the initial phase (e.g. for power plant projects implemented up to 2025).
- There is a less pressing or obvious need for corresponding requirements in relation to existing plants and controllable load resources because the respective facilities and/or measures will be used or effective for a shorter period of time. If applicable, flexibility and emission requirements could be introduced for existing capacity at a later stage.

The providers who succeed in the auction must be able to produce evidence confirming their contribution towards safeguarding capacity. The form this should take must also be specified for the (various) products traded on the capacity market:

- Evidence of this kind is essential for controllable load resources. International models such as PJM's capacity market (PJM 2011) stipulate that demand response resources are called on for up to six hours at a time on as many as ten occasions per annum. Considering the potential available, shorter periods of time could serve as a basis here.
- Operators of generating capacity must prove that their plants were available for production during the periods of time relevant for security of supply. Given the price levels to be anticipated on the spot market at these times, it will generally be possible to assume that they were. Operators could also be required to produce evidence such as a bid on the energy exchange or an appropriate supply obligation.
- The facilities in question would have to produce evidence of a certain minimum time availability as per the VGB definition (2008) during peak periods. Taking the relevant power plant classes into account, a minimum time availability of 90% would be prudent and appropriate during peak periods.

These requirements would ensure that evidence of the relevant facilities' physical availability was produced.

So as to limit the costs for energy consumers, it makes sense to link evidence of physical availability with a call option for the successful bidders in the capacity market. The call option gives the responsible body the right to payment of the difference between the spot price available on the wholesale market and a fixed threshold (strike price). It is logical for this strike price to be higher than the marginal seller's marginal costs in the system (with a certain safety margin). This would not prevent scarcity-induced prices on the electricity market, but it would absorb scarcity-induced premiums and make them available to reduce the cost of the necessary capacity contributions on the consumer side.

This combination of (physical) capacity provision and call options is not absolutely essential, but it is prudent as a means of curbing consumer costs. The alternative is trading capacity options on the capacity market without evidence of physical availability. This is not a viable option to safeguard security of supply in real terms because this model would open up the possibility of purely financial capacity provision, which may not provide the necessary capacity in the case of a shortage and could make a mockery of the capacity market's objective.

To summarise, the following product structures can be derived for the focused capacity market model:

1. Capacity payments spanning 15 years combined with technical qualification criteria for new plants. During the introductory phase, it may be wise to limit this to regions with grid bottlenecks. Evidence of physical availability must be produced; this is associated with a call option.
2. Capacity payments spanning one year for existing power stations. Evidence of physical availability must be produced; this is associated with a call option (technical qualification criteria can be added at a later date). Tendering process using this product for approx. 25% of the volume sought from the existing plant segment.
3. Capacity payments spanning four years for existing power stations. Evidence of physical availability must be produced; this is associated with a call option (technical qualification criteria can be added at a later date). Tendering process using this product for approx. 75% of the volume sought from the existing plant segment.
4. Controllable load resources can take part in the auction for both products in the existing capacity segment. They must guarantee that demand response resources can be called on for up to six hours on ten occasions (or less), for example.

This kind of product structure would enable a market to be established with a sensible auction frequency (see subsection 0) which could be expected to boost liquidity, support the necessary learning process and remain sufficiently adaptable.

5.4 Auctions and capacity provision

Capacity auctions (for power plants or controllable loads) are a central element of the focused capacity market. The following key aspects must be considered when drafting the specifications for the auction procedure (Matthes/Neuhoff 2007):

1. Who will be allowed to take part in the auction?

2. How many rounds should the auction consist of?
3. What pricing mechanism should the auction be based on?
4. How often should capacity auctions be held?
5. Should volume restrictions be introduced for bids?
6. Should specific market monitoring be conducted?

Other options for the auction's format at procedural level (e.g. the question of who should hold the auction) are examined in subsection 0.

The basic structure of the auctions is fundamentally determined by the two segments of the focused capacity market: there will be an auction for existing capacity (including controllable load resources) and an auction for new power plants. This essentially means that two different auctions will be held.

Permission to take part in one or both auctions is derived fairly strictly from the definition of the different segments and products:

- Legal entities who have access to physical capacity and/or have proved during the pre-qualification process that they will have access to physical capacity may take part.
- These legal entities must also fulfil the economic and legal requirements associated with entering into a call option obligation.[27]

The number of auction rounds depends heavily on the amount of market information available. Single-round auctions tend to be held in highly liquid markets with a wide range of participants, where a large amount of information is available and transparent. This applies to auctions on the energy and CO_2 markets, for instance. However, several rounds are often used for auctions which have a stronger focus on price setting and where there is a high level of uncertainty (an extreme example would be auctions for mobile network licences).

Despite their close proximity to the fuel, electricity, balancing power and CO_2 markets, capacity auctions are characterised by a high level of uncertainty and can be expected to attract a limited range of participants, at least during the initial phase.

Against this backdrop – and considering international experience – it would make sense to use a multi-round auction based on the descending clock method so as to limit the cost to consumers:

- The auctioneer opens the first round by offering a starting price for the predefined total capacity. This could be in the range of approx. €40 to €50/kW (fixed costs for facilities under threat of decommissioning) for existing power plants (including controllable loads). A figure between €50 and €75/kW would

[27] This analysis does not go into these requirements in greater detail. Dedication specification analyses must be conducted in this regard.

be appropriate for new generating capacity (budgetary deficit for many new-build options). The pre-qualified bidders submit their bids for the lot sizes prescribed for the auction (e.g. in multiples of 5 MW in line with the regulations for the balancing power markets).

- If supply exceeds demand in the first round, the auctioneer offers the total capacity volume at a reduced price. The bidders submit new bids.
- This process is repeated until the offers meet the total capacity being sought.

The bidders who are successful in the final round are awarded contracts for the respective capacity payments and may have to issue a call option if applicable.

A multi-round procedure using the descending clock method for the focused capacity market implies that this is a price setting process. Contracts are awarded at a standard rate. Other price setting processes such as those used in the balancing power markets (pay as you bid) would be possible in principle for a single-round auction. However, as they would strongly encourage strategic bidding, they would not be suitable for alternative auction types in the context of the focused capacity market.

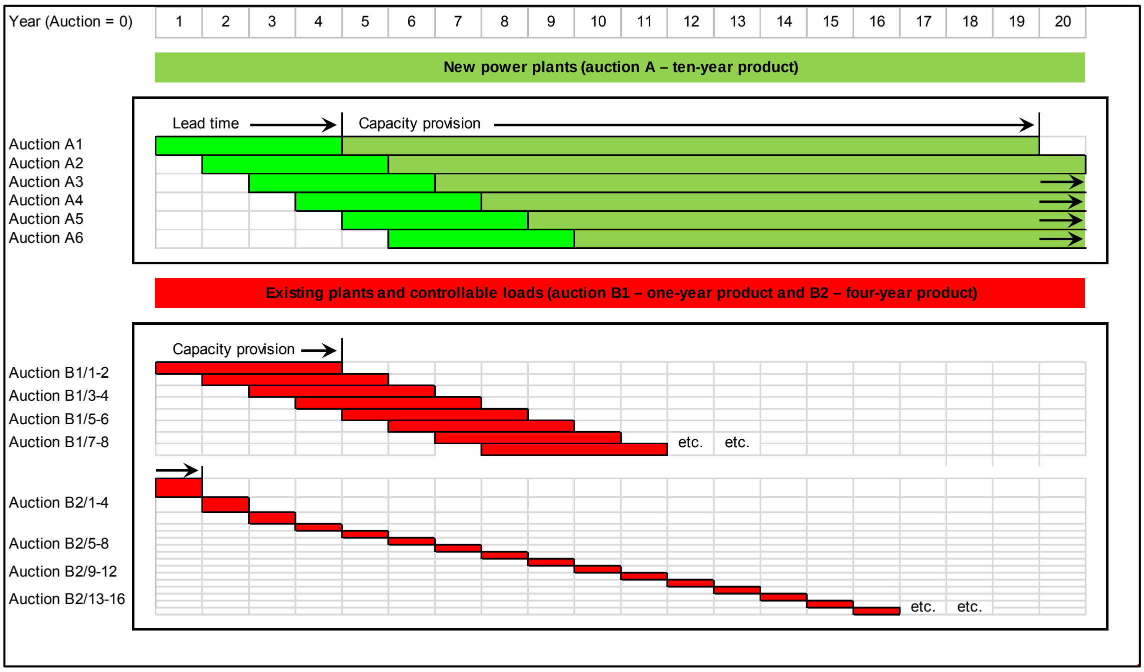
The different segments' various requirements determine the frequency of the auctions:

1. An annual auction is the obvious solution for the one-year product for existing power plants (see subsection 0). This is also true given that the one-year product is probably an ideal interim option for the introductory phase of the focused capacity market and may be attractive for a wide range of controllable load resources (see subsection 0).
2. The auction frequency for the four-year product for existing capacity (see subsection 0) depends on the size of this segment. If existing power stations under threat of decommissioning have a large total capacity, the segment could be split up and also integrated into the market via annual auctions. A four-yearly auction would be appropriate for a smaller segment. If access to controllable load resources (see subsection 0) is to be made easier, annual auctions would probably be well advised and appropriate for the whole existing capacity segment.
3. Given the considerable lead time needed in the new-build segment (see subsection 0), annual auctions would also be prudent and expedient for this segment. However, the total capacity sought at each auction must be weighed up against the anticipated supply and provider structure plus liquidity aspects in the light of concrete parametrisation.

Figure 12 offers an impression of the focused capacity market's structure. The system starts with a comparatively large proportion of tenders for the one-year product in the existing capacity market (auction B2), which decreases as the number of auctions for the four-year product increases (auction B1). In the new-build segment (auction A1), the focused capacity market is introduced with annual capacity tenders of, for example, 1,000 MW. However, the respective projects only materialise several years later for obvious reasons.

At the same time, this overview illustrates one of the advantages of the focused capacity market, which is derived from the segmentation of both the market and the products. The system can be introduced gradually and a rapid roll-out can be guaranteed – especially in the existing capacity segment, which is relevant short term – thanks to enhanced flexibility on the product side.

Figure 12 Overview of focused capacity market products and possible auction dates/frequency



Source: Öko-Institut.

Bidder power is a generic problem for all auction types. This challenge is usually tackled by restricting the percentage of business awarded to any one provider. In this case, the bidders have to issue a legally binding declaration that they are not associated with any other bidder. In the energy industry, the auction procedures used for gas release programmes could serve as a prime model. Here, bids are restricted to a maximum of one third to half of the capacity sought (Matthes/Neuhoff 2007). Considering the overall parametrisation of the focused capacity market, there needs to be a further analysis and specification of whether restrictions are necessary and, if so, what form they should take.

Like all auction processes, the capacity market auctions should be subject to a monitoring process. Full details of bids and contracts should be submitted to the body responsible for monitoring, which should be able to analyse them for any indications that market power is being abused. In addition to this specific market monitoring system, the data should also be made available to the body responsible for safeguarding security of supply so that this aspect can also be analysed.

The capacity provision periods for the successful bidders in the focused capacity market auctions differ by segment:

- In the existing capacity segment, operators start providing capacity in the year following the auction or receipt of the contract. The successful bidders submit evidence of their time availability and bids made on the spot market to the relevant body and refund the difference between the strike price and the market price to the relevant body when the call option is exercised.
- Providers of controllable load resources must supply the defined load reduction offered within the existing capacity segment of the focused capacity market (see subsections 0 and 0) when they are called on by the relevant body.
- In the new-build segment, the provision of capacity begins when the plant commences commercial operations. This should be no later than five years after the auction or receipt of the contract. The successful bidders submit evidence of their time availability and bids made on the spot market to the relevant body and refund the difference between the strike price and the market price to the relevant body when the call option is exercised. In the period between being awarded the contract and the go live deadline, plant operators must inform the relevant body of their progress regarding the plant’s physical availability on an annual basis.

A decision has yet to be made on whether – and to what extent – a capacity market based partly on call options (i.e. supply obligations) needs further penalties for operators who fail to provide the relevant capacity.

5.5 Participating in other energy market segments

The question of how the generating capacity that wins the capacity auctions is integrated into the market is of key importance for the design of capacity markets. Basically, there are two options:

- Maintaining back-up capacity outside the market (the strategic reserve concept makes use of this option).
- Allowing this capacity to participate in the market (this option is typical of traditional capacity market models).

There are at least four reasons why capacity which is awarded a capacity payment after successfully taking part in an auction on the focused capacity market should be allowed to participate in the energy market segments which already exist today:

1. The price level in the energy-only market is determined by the amount of competition. In the interests of consumers, the existing high level of competition with low electricity prices must be maintained. Prohibiting operators from participating in the energy-only market would reduce supply. In turn, this reduction would lead to less competition and rising prices. Banning operators from the energy-only market aims to increase electricity producers’ margins at

the consumer's expense. This should be prevented. For this reason, the capacity under contract should be allowed to participate in the market.

2. The focused capital market concept also aims to gradually launch flexible generating capacity – which will be in great demand in the future – onto the market. If new-build power plants of this kind were unable to participate in the market, it would no longer be possible to achieve this objective and the respective pre-qualification requirements would be pointless.
3. The focused capacity market should maintain incentives to tap energy-saving potential (e.g. by unbundling heat or other means of boosting efficiency) so as to gain access to sources of income other than capacity payments and thereby contribute towards the dynamic improvement of the whole system's efficiency. This option would not exist if operators were prohibited from participating in the energy market.
4. If demand-side measures are to be incorporated into the focused capacity market using a non-selective approach (i.e. a special market segment is not to be created for demand-side measures) and these activities are to be effective on the demand side of the energy market, it would be inconsistent – if nothing else – to exclude supply-side measures.

If there is sufficient competition at the capacity auctions, the market players will factor contribution margins from the energy-only market into the capacity auctions. This will make for lower bids at the capacity auctions. Peak-load plants which are operated for a few hours would be the only facilities unable to factor in contribution margins from the energy-only market. They would therefore submit higher bids equivalent to their fixed costs. By contrast, plants with more operating hours could factor their anticipated contribution margins from the energy-only market into the capacity auction. This could enable providers with higher fixed costs to remain competitive at the capacity auction.

When they participate in the balancing power market, suppliers of balancing power gear their quotes towards their realistic options. For power plant operators, this typically means the energy-only market. If a capacity provider wants to offer his capacity on the balancing power market, he has to forego marketing it on the energy-only market and therefore do without the revenue this could generate. This means the provider will only offer rates on the balancing power market which enable him to generate at least the same amount of profit as he would via the energy-only market. Bids for the balancing power market are therefore based on lost profits from the energy-only market. This correlation means that prices on the spot and balancing power markets will become aligned, enabling plant operators to realise comparable production margins on both markets.

For these reasons, capacity providers who are successful within the focused capacity market should be able to participate in both the energy-only market and the balancing power market, without being subject to any restrictions in this regard.

5.6 Procedural implementation

Procedures and responsibilities need to be specified for the concrete implementation of the focused capacity market. It is already possible to describe the procedures to a great extent. However, there are several options for the allocation of various responsibilities, which it will only be possible to appraise as time progresses and based on the concrete implementation option chosen.

Whenever any capacity instrument is launched (not just the focused capacity market), it is essential to identify the associated requirements to the greatest possible extent. There are several different dimensions to this:

- Compiling as comprehensive a record as possible of the existing power plant fleet. Although Germany’s Federal Network Agency has made considerable progress in completing the data available with its power plant lists, there are still substantial gaps concerning decentralised plants and private generating capacity.
- Developing a reliable projection for how electricity usage and peak-load requirements will develop. A whole host of forecasts must be taken into account, which can only be narrowed down reliably with the aid of corresponding sensitivities.
- Developing a realistic picture of the capacity to be decommissioned. Calculating the volume of capacity to be retired requires a large number of technical, legal and economic parameters and can only be identified reliably with the aid of extensive sensitivity analyses.
- Calculating the volume of imports and exports which can be expected to meet peak loads. Here too, sensitivity analyses are needed to calculate reliable figures.

This means that an extensively validated output forecast is needed which is updated regularly. The processes used to draft the grid development plan could be used as a model for a ‘monitoring and forecast report on security of supply’ (security of supply report). The underlying assumptions, methods and results of this plan are all subject to an intensive consultation process along with variation calculations to increase the reliability of the results. The security of supply report could be developed and drafted every two or three years in close connection with the annually produced grid development plan and the associated processes. This would make it comparatively simple to put the procedure in place. This security of supply report could be drafted by the body responsible for implementing the focused capacity market or by the relevant government agency. It would have to be approved by the relevant government agency, initiated by the German government and submitted to the *Bundestag* (lower house of the German parliament) for the ministers’ information.

A capacity register would have to be drawn up as well as the security of supply report. Although a register should ultimately be created for all generating capacity which feeds into the grid (like the one which already exists for power-generating units using renewable sources), it would make sense to initially set up a register which existing and new plants (or new-build projects) must be included in if they intend to take part in the focused capacity market auctions. The register should include at least the parameters necessary for participation in these auctions. Controllable load projects could also apply for inclusion in the register. As a minimum, they would also have to provide the information which entitles providers to participate in auctions and/or is necessary as evidence of providing capacity.

The various plant operators or resource providers would also have to state at a certain point that they were taking part in the existing capacity or new-build auction, either when they were entered in the capacity register or at a later date. It would make sense for this to be done after the security of supply report has been commissioned. By registering to participate, operators or resource providers would be obliged to take part in the next auction round for their segment (even if this meant submitting a bid of €0) and be bound by the capacity provision conditions if they were awarded the contract.

Based on the information in the capacity register and an evaluation of the security of supply report, the relevant government agency would determine the size of the auction segments, possibly in conjunction with a forecast for the next two or three years. This would be done so as to ensure that the auction segments were smaller than the total capacity of the registered plants, projects or demand-side measures to a sufficient degree to enable a successful auction to be held. If the security of supply report concluded that there was no need to safeguard existing power plants or build new ones, an auction could be held exclusively for demand-side measures. If the security of supply report identified a need for the capacity auctions to have a particular regional focus (which could prove particularly relevant in the shorter term), this would be taken into account when determining the auction segments.

The auctions for the existing capacity and new-build segments would be conducted by the relevant body or by a third party acting on the former's behalf. The auction procedures have already been tested in a wide range of contexts and are also offered on commercial platforms. The relevant body would award contracts for the various capacity payments and hold the call options.

The relevant body would also call on any controllable load resources which were successful in the auction. At this point, the evidence necessary for capacity provision (see subsection 0) would also have to be submitted. This could take the form of auditors' certificates, which are required by a number of other energy industry provisions (the German Renewable Energy Sources Act, the German Combined Heat and Power Act, etc.).

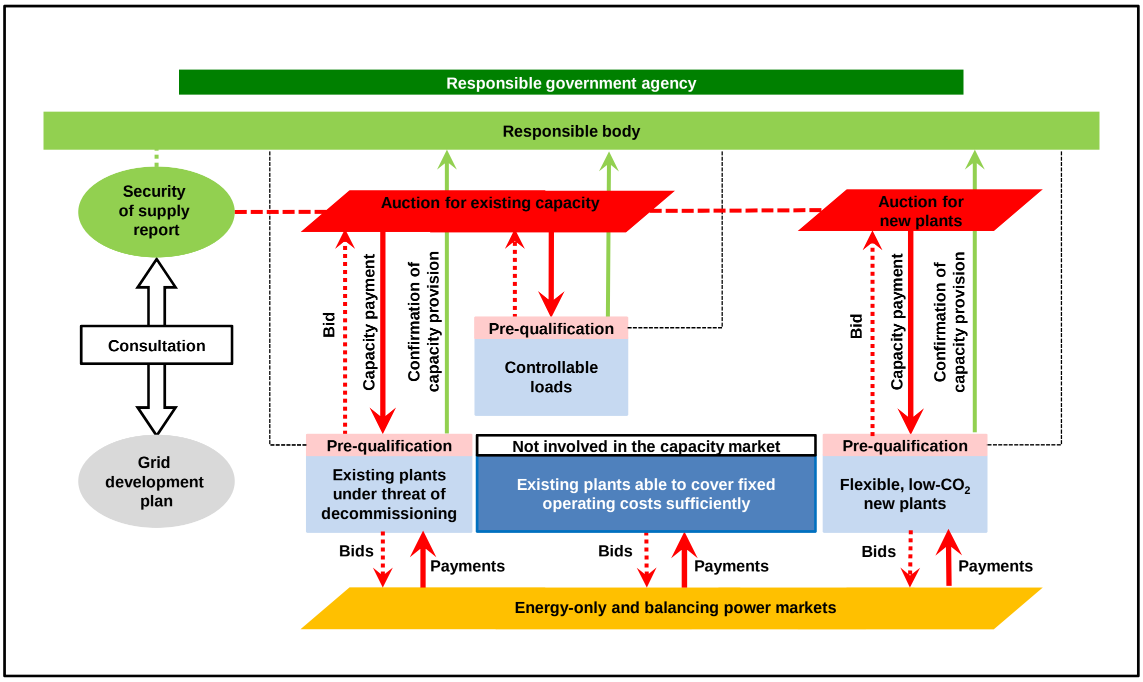
The cost of the capacity payments, preparing and conducting the auctions, and processing the documents confirming capacity provision would be passed on. There are two options:

- They become part of the transmission system rates and charged to the relevant accounts.

- They are levied as a transparent charge.

If security of supply is considered to be a public commodity, it makes no sense to give certain consumer groups privileges if the latter option is chosen (based on the model of charges for the German Renewable Energy Sources Act, the German Combined Heat and Power Act or Section 19 of the German Electricity Grid Charges Ordinance).

Figure 13 Overview of the procedures and functions of the focused capacity market



Source: Öko-Institut.

When assigning responsibilities for the various procedures and/or functions of the focused capacity market (Figure 13), it would be possible to either create new institutions or build on existing structures.

Should the latter option be chosen, awarding this responsibility to transmission network operators would be the most obvious solution in the short term. This poses a particular challenge as concerns the situation in Germany because Article 8(5) of the Electricity Directive states that transmission system operators which are not fully independent may not be involved in organising capacity auctions. As things stand, this would primarily affect the transmission network operators TransnetBW (wholly owned by ENBW) and Amprion (25.1% stake held by RWE). These two transmission network operators would therefore not be permitted to act as responsible bodies within the model described here.

The best short-term solution is the German Federal Network Agency, which already fulfils a number of similar roles for the electricity grid and the telecommunications networks.

In the longer term, this situation could change considerably, however, for example if an independent system operator (ISO) is to be established in the context of other problems associated with the deregulated electricity market. Setting up an ISO which is responsible for operating and expanding the grid system but does not own the network is currently proposed in Article 13 of the Electricity Directive primarily as an alternative to unbundling the transmission network operators (which Germany has already done). However, this could become a development model for Germany in the future. In this case, it would make sense for the ISO to assume the role of responsible body in the context of the focused capacity market too.

Last but not least, there is the option of creating new institutions – something which is suggested in the proposal for a comprehensive capacity market in Germany (EWI 2012), for example.

As regards the institutional arrangements for the focused capacity market, it only remains to note that all the tasks can be performed by existing institutions and that the various functions are also simple and robust enough to be adapted relatively easily in a changing institutional landscape.

5.7 European integration

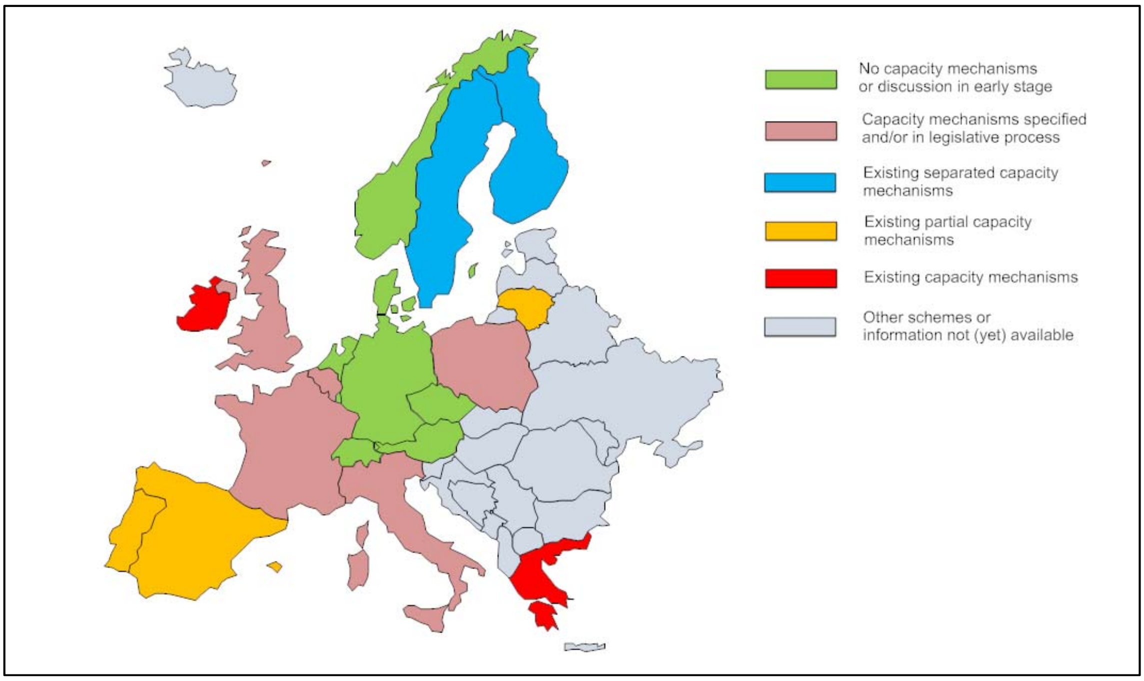
5.7.1 An overview

The current and prospective challenges associated with security of supply and the realignment of the electricity market which is necessary long term raise a paradox of European energy policy – and not for the first time. Although Europe's domestic market for electricity has developed more slowly than policy makers would have liked, a series of relatively well-functioning regional markets has emerged. Now as in the past, the approach taken to achieve this centres on linking markets and expanding trading areas with limited intervention.

However, the responsibility for security of supply still rests firmly with the Member States for the time being. There is no EU institution or an equivalent agency for any of the regional markets to which supra-national responsibility for security of supply has been – or is due to be – transferred.

In other words, the reality of an increasingly integrated (regional) electricity market conflicts with the reality of the strict assignment of responsibilities and roles concerning security of supply to date. Given the ongoing grid bottlenecks for cross-border electricity transmission, there is limited justification for the existing system.

Figure 14 Capacity mechanisms in Europe, 2012



Source: Nies (2012), Öko-Institut.

European solutions are often demanded in the debate surrounding the electricity market. Given the realities of the energy-only market, this is the right approach in abstract terms, but the necessary institutional framework is not currently in place. To date, the cross-border assessment of security of supply by ENTSO-E as part of its annual System Adequacy Forecast (SAF) has been informative in nature. It is produced primarily from the network operators' perspective and does not therefore assess how likely it is that registered power plant projects will be implemented; nor does it trigger any compulsory measures (ENTSO-E 2012).

Against this backdrop, it is no surprise that capacity mechanisms have been created, are planned or are imminent in many EU Member States in response to the real challenges posed by security of supply (Figure 14). These Member States include countries which:

- Introduced capacity mechanisms of various kinds at an early stage of electricity market deregulation (Scandinavia, Spain, Portugal, etc.)
- Are reacting to the problems which occur at the end of the transitional phase of electricity market deregulation and in which discussions concerning capacity instruments are already very well advanced (Italy, Belgium, Poland)
- Have in some cases already developed concrete legislative proposals (the UK, France)

It is therefore fair to say that the discussion surrounding capacity markets in Germany is by no means more advanced that the discussions and political measures in neighbouring states. In fact, the very opposite is true. Finally, most of Germany's neighbours in Continental Europe – with the exception of the Netherlands and Austria – have already started seriously considering capacity mechanisms at the very least. Many of them are already making highly practical preparations in this regard.

Regardless of the fundamental question of whether capacity mechanisms are deemed necessary at cross-border level (cf. subsection 2.3) and regardless of the question discussed above of whether the institutional requirements are met for implementing capacity mechanisms throughout Europe – or at least for regional markets – the interaction of electricity markets which are interlinked supra-nationally remains of key importance. This relates to both the design and parametrisation of capacity mechanisms and the evaluation of the relevant cross-border (knock-on) effects.

In particular, the question should be raised as to whether the possibility of cross-border electricity sharing changes the conclusions reached at national level about the need for capacity mechanisms, their scheduling and their design.

The question of whether capacity mechanisms are needed will only be answered differently with regard to national, regional or European markets if it is possible to fundamentally rule out the functional deficits of the energy-only market with regard to security of supply. In this case, the European or regional market would secure the necessary investments, but not necessarily within the relevant national borders. However, if the functional deficits are taken seriously, they will materialise throughout the market area. The fundamental question of whether capacity mechanisms are needed would then no longer be raised. Instead, the issue would at most be when to initiate the inescapable creation of these instruments.

Firstly, it must be considered whether the appraisals of the capacity needed to safeguard security of supply in Germany would reach a different conclusion if the possibility of cross-border electricity sharing was incorporated into the analyses. However, it must be remembered that high loads and a shortage of capacity are not an isolated problem for Germany alone. Instead, they often pose a general problem for the whole Continental European market (especially France, Switzerland and Austria).

Analyses completed in February 2012 of the shortage situations which have occurred to date (BNetzA 2012) show that although the capacity-side situation was tense for various reasons and back-up power plants had to be activated in Germany and Austria, several gigawatts of electricity were still exported to Austria at the same time. Germany also simultaneously imported a considerable volume of power from Scandinavia. For Germany, the integration of the electricity market has caused more problems than it has alleviated, at least as regards regional security of supply. This is not true at all times and in every situation, but it shows that it is by no means possible to determine whether cross-border electricity sharing makes a positive or negative overall contribution to security of supply. It certainly cannot necessarily be assumed that it helps Germany to safeguard security of supply.

Two conclusions can be drawn from this finding as regards the design and/or parametrisation of the focused capacity market:

- Firstly, there is no doubt that a much stronger focus must be placed on the cross-border component of the shortage analysis. However, access to the relevant instruments and liaison procedures is as yet incomplete, not least in terms of cross-border dialogue.
- Secondly, however, the shortage situations seen to date and capacity trends in neighbouring countries could be said to justify the conclusion that Germany needs to ensure it has sufficient national capacity to meet national load peaks – at least as a starting point – and that there may be demand for export capacity on top of this.

Both aspects therefore need to be considered in depth as part of the security of supply report, which must identify the key volume-related requirements for the focused capacity market instrument.

In addition to the volume aspect of the focused capacity market (i.e. the definition of the existing capacity and new-build segments for the auctions), the question must be considered as to whether foreign power-generating capacity can be permitted to bid in the respective auctions. This question is ultimately raised at two levels:

- In the new-build segment at least, bids from foreign providers could be permitted for power stations which are operated in a single price zone (this currently affects Germany, Austria and Luxembourg), provided that this does not go against the pre-qualification requirements, e.g. regarding localised power plants in certain network areas. If the countries in question also introduced capacity mechanisms, it would be necessary to ensure that capacity was not marketed twice.

- This kind of approval could not currently be granted for power stations operated outside the single price zone, due in particular to the limited transmission capacity.

Finally, the question of potential knock-on effects must be considered if Germany were to introduce a capacity mechanism which enabled power plants receiving capacity payments to take part in the energy-only market unrestricted (Cailliau 2011). An examination of developments in neighbouring countries makes it clear that the introduction of a focused capacity market could by no means be guaranteed to trigger positive knock-on effects for Germany's neighbours, given that similar – and in some cases significantly more advanced – concepts or legislative projects are already in place. This would constitute a significant barrier to the launch of such an instrument in Germany.

5.7.2 Legal position

The introduction of focused capacity markets by national legislators and lawmakers is permitted under European law.

According to Article 194(1)(b) of the Treaty on the Functioning of the European Union (TFEU), one of the aims of the Union's energy policy is to guarantee security of supply in the Union. Article 194(2) sentence1 of the TFEU states that "the European Parliament and the Council, acting in accordance with the ordinary legislative procedure, shall establish the measures necessary to achieve the objectives in paragraph 1".

Regardless of whether a capacity market is considered necessary at European level pursuant to Article 194(2) sentence 1 of the TFEU, the Member States are permitted to take action in the absence of final provisions issued by the Union: Article 4(2)(i) of the TFEU defines the principal area of energy as a shared competence between the Member States and the Union. Article 2(2) sentence 2 of the TFEU therefore permits the Member States to exercise their competence to the extent that the Union has not exercised its competence.

The European legislators also explicitly entrust the creation of capacity markets to the Member States in Article 8 of the Electricity Directive. By doing so, the secondary legal provisions explicitly exclude the field of capacity markets from conflicting Union legislation and assign it to the Member States.

There are no obstacles to the creation of focused capacity markets under competition law either. Pursuant to Article 107(1) of the TFEU, "any aid granted by a Member State or through State resources in any form whatsoever which distorts or threatens to distort competition by favouring certain undertakings or the production of certain goods shall, in so far as it affects trade between Member States, be incompatible with the internal market".

Advantages are not considered to be “granted through State resources” if they are based solely on a legal provision. They are only defined as such if they are granted by a public or private institution nominated or established by the State (European Court of Justice, verdict dated 24/1/1978, case no.: 82/77, NJW 1978, 1102, 1103 – *Van Tiggele*). For this reason, the obligation to purchase electricity from renewable sources at minimum prices was deemed permissible under aid law (European Court of Justice, verdict dated 13/3/2001, case no.: C-379-98, EuZW 2001, 242 – *PreussenElektra).* This means that a statutory capacity charge which is payable by transmission network operators does not constitute aid as defined in Article 107(1) of the TFEU.

There are no grounds for believing that the introduction of a focused capacity market would violate competition law. If capacity is withheld artificially, this can constitute the abuse of a dominant position within a market as per Section 19 of the German Restraint of Competition Act (GWB) or Article 102 of the TFEU. It could also be considered to violate the ban on market manipulation as defined in Article 5 of the EU Regulation 1227/2011 dated 25 October 2011 (REMIT) and/or Section 20a of the German Securities Trading Act (WpHG).

5.7.3 Moving forward: one option

The introduction of a capacity mechanism such as the focused capacity market is legally permissible for Germany and could be effected comparatively robustly and quickly using the procedures outlined above. However, it is very important that capacity mechanisms be harmonised for several reasons (efficiency, distribution effects, system consistency, etc.).

Attempts to bring about harmonisation of this kind face a whole host of challenges, however. Firstly, capacity mechanisms must take effect – especially as regards real investments – within a limited space of time. If there is a further delay in implementing capacity mechanisms lasting several years, Continental Europe’s electricity market at the very least will face considerable challenges in terms of safeguarding capacity. Secondly, political measures (especially in France) are already so well advanced that attempts to harmonise a capacity market model would mean that far-reaching changes may have to be made to an existing system. This would pose considerable political barriers to harmonisation.

Four conclusions can be drawn from this situation concerning the options for harmonisation (which is worth striving for):

- Harmonisation efforts will only succeed if they are initiated relatively quickly.
- Harmonisation efforts should concentrate primarily on regional markets which already have a high degree of integration and not on an EU-wide approach.
- Harmonisation efforts could initially focus on a few key elements of the chosen capacity mechanisms, e.g. the volume targets set for the relevant systems (taking reliable assumptions for the role of cross-border electricity deliveries into account).

- Although capacity mechanisms may initially be introduced separately in individual countries in the face of rising pressure to act, they should be flexible enough to be able to be incorporated into integrated models at a later date. In other words, neither highly complex capacity mechanisms which are difficult to adapt (such as comprehensive capacity markets) nor very restrictive solutions (such as those proposed under the strategic reserve) should be introduced, which would ultimately require capacity to be excluded from the energy-only market.

As the instrumental and procedural framework for EU-wide activities will probably make it difficult to take action in this way, it must be considered whether it might be possible to roll out this kind of harmonisation approach (gradually if necessary) at regional market level. The Pentalateral Energy Forum established in 2005 for North-Western Europe's regional market has proved successful in the past when it comes to gradually linking and integrating markets. This forum brings together governments, regulatory bodies, transmission network operators, energy exchanges and market players from Germany, France, the Netherlands, Belgium, Luxembourg and Austria (since 2011). It has made significant progress on an informal basis (not binding under public international law) in integrating the markets which make up the Central and Western European regional market. The forum has also launched important initiatives relating to the grid system in the North Sea (PEF 2007, Ahner/Boulemia 2010). The Pentalateral Energy Forum can also draw on a relatively well-coordinated institutional framework.

An initiative could be rolled out at relatively short notice under the aegis of the Pentalateral Energy Forum with the following prime objectives:

- Agreeing on a procedure for delimiting cross-border electricity deliveries in the context of assessing the individual countries' security of supply in an appropriate, sufficiently robust fashion.
- Creating a consistent set of data and jointly assessing security of supply[28].
- Signing agreements about harmonising central functions of the chosen capacity mechanisms.
- Establishing processes for mutual inclusion in the capacity mechanisms created in this way.

Given that time is at a premium (as regards both the security of supply discussion and developments in neighbouring countries), initiatives of this kind should be pursued at the same time as making the necessary preparations to establish a focused capacity market.

[28] It should be noted that evaluating Germany's security of supply would constitute a learning process, especially for the German Federal Network Agency (BNetzA 2011a+b+2012).

5.8 A possible timescale

The time-frame for the introduction of a focused capacity market depends on both the material need to act (i.e. the necessity to support existing plants and new investments) and the numbe of implementation measures and processes involved.

With both of these aspects in mind, the following illustrative timescale could be conceivable:

- Autumn 2012/early 2013: Examining the question of whether a capacity mechanism is fundamentally necessary and considering the elementary issue of whether it is prudent and/or necessary to exclude plants which receive capacity payments from the energy-only market.
- Throughout 2013: Extensive discussion about the instrument's fundamental design and key parameters, consultations as part of the Pentalateral Energy Forum if applicable.
- November 2013: Incorporating a pledge to introduce a focused capacity market into the coalition agreement.
- Mid-2014: Establishing the legal framework via an amendment to the German Energy Industry Act.
- Autumn 2014 to summer 2015: Drafting the 2015 security of supply report in conjunction with the 2015 grid development plan, establishing the delegated legislation, setting up the capacity register.
- Autumn 2015: Approving the security of supply report, giving notice of auction participation to the capacity register.
- Late 2015/mid-2016: First auction for the existing capacity and new-build segments (stronger regional focus possible for the latter).
- Early 2016/2017: First capacity payments to existing plants and/or controllable load resources, final investment decisions by successful bidders in the new-build segment.
- Mid-/late 2017, 2018, etc.: Further auctions for the two segments of the focused capacity market.
- Throughout 2019/2020: Going live with the first new plants to generate income from capacity payments.

Even this relatively ambitious timetable shows that the time-frame for introducing a capacity mechanism is already very tight if a solution is to be found within this decade to support the power plants under threat of decommissioning and if new investments are to create capacity which can go into production at the beginning of the next decade. The timetable is virtually the same for the focused capacity market as for a comprehensive capacity market or the creation of a strategic reserve, as different functions and provisions have to be created for each.

However, the processes outlined here also show that it may be necessary to find alternative solutions for the period up to 2016/2017, especially to safeguard existing plants. Ideally, the relevant measures would be rolled out in such a way that suitable elements of the focused capacity market (pre-qualification requirements, register, tendering procedure, etc.) could be trialled at this early stage.

6 Placing the focused capacity market on the spectrum

6.1 Preliminary remarks

In the previous sections, the capacity instrument of a focused capacity market was specified in detail and the key parameters were indicatively estimated (parameters which would then have to be robustly determined in a transparent manner in the processes described above when it came to the concrete implementation of the instrument). Based on this, we can undertake an initial placement of the focused capacity market on the spectrum of capacity instrument proposals. The analysis presented here does not endeavour to deliver a comprehensive comparison of the various capacity instruments (a number of the proposals are still too poorly defined for such a comparison to be conducted anyway), so the placement of the focused capacity market shall be limited to the following aspects:

- The cost of implementation
- The regulatory risks
- Its adaptability
- Its reversibility
- Its distribution effects
- Its (dynamic) efficiency
- Its learning aptitude and the contribution it makes to restructuring the energy system

For reasons of clarity, these aspects will all be discussed from a qualitative perspective in the following deliberations. Further research is needed ahead of the quantitative analyses that are likewise needed for full placement on the spectrum.

6.2 The cost of implementation

At first glance, it would appear that the steps for specifying the market segments relevant to each model are essentially the same in each case:

- For a focused capacity market, a benchmark must be defined for the total capacity needed in order to guarantee security of supply (including cross-border electricity flows), preferably in agreement with the neighbouring states or the countries in the same regional market. This step is also necessary for all other capacity instruments and should be implemented with the same transparent procedures. In the case of the comprehensive capacity market, however, the total capacity must also be recorded procedurally (i.e. in terms of the registers, pre-qualification for the auctions, etc.) and at the level of the individual plants. But the concomitant need to fully record capacities at the plant level can, as experience has shown, result in considerable expenses (the final segment of total recording leads to disproportionately high expenses).

- Both for the focused capacity market and the strategic reserve model, the target segments for the capacity instrument in question have to be specified. The expenses incurred for this would likely be the same in both cases. This is not absolutely essential for the comprehensive capacity market, but if it becomes necessary to differentiate between segments here too (term of the capacity payments, inclusion of controllable loads), the segments in question would possibly also have to be demarcated.

There is ultimately no difference between the models in terms of the awarding procedure, with the vast majority of the known proposals for capacity instruments being based on descending-clock auctions. Naturally, market liquidity is biggest in the case of comprehensive capacity markets (assuming there is no further segmentation) and smallest in relation to the strategic reserve model, while the focused capacity market falls somewhere between the two. Lower market liquidity then leads to greater expenses in relation to market monitoring and possibly also necessary regulations and interventions.

Qualitatively speaking, complying with the obligations is very similar in each case, but entails a larger basic total of plants in the case of the focused capacity market and the comprehensive capacity markets, and is therefore more expensive by definition.

In terms of lead time, a realistic consideration of all the implementation steps suggests that there will ultimately not be any significant differences.

6.3 Regulatory risks, adaptability and reversibility

There are regulatory risks involved in all of the proposed capacity instruments. While these first and foremost arise as a result of system parametrisation in the case of the comprehensive and the focused capacity market and can be handled in the form of procedures which are as robust as possible, the regulatory risks pertaining to strategic reserve above all relate to the operational stage (approval of capacities above and beyond shortage situations that can no longer be remedied via the markets, watering down of the 'no way back' principle), are, based on the experience garnered in comparable situations, therefore characterised by a very situational component and are far more difficult to contain, procedurally speaking.

There is adaptability in all of the models. The comprehensive capacity markets that already exist (such as in the USA) have been modernised time and again, and the segmented capacity instruments that have been implemented so far have likewise in effect been adapted again and again as and when needed. The primary difference relates to the expenses incurred for the adaptation measures. In comprehensive capacity markets, such adaptations are more costly due to the full recording of plant capacities. The cost of adaptations is also not marginal in the case of segmented sales such as in a focused capacity market or with strategic reserve, but the adaptations to be made to the system tend to be less complex and to some extent the necessary adaptations can also be integrated into the system on the basis of rules (e.g. with the dynamic demarcation of the segment of plants under threat of decommissioning in the focused capacity market).

The question of reversibility has to be evaluated in context. In the case of comprehensive capacity markets that continuously generate income for capacity for the entire power plant fleet, the abolition of this pricing mechanism constitutes an economic shock, the consequences of which are difficult to estimate – not even their direction can be forecast. The upstream stage, i.e. the motivation behind the planned abolition of the system, therefore likewise has to be included in the considerations of this dimension for comprehensive capacity markets. If the introduction of a capacity market is founded on the presumably reliable assumption that energy-only markets are not a sustainable basis for the development of the power supply system, reversibility is not a crucial analysis dimension.

In contrast, the various strategic reserve models are explicitly defined as transitional models until the long-term efficiency of energy-only markets in terms of security of supply, etc. has been determined. Regardless of when the uncertainties regarding the overall portfolio's relevant determinants (CO_2 and fuel prices, the development of the plant market, the characteristics of the expansion of renewable energies, the development of the European environment, etc.) allow for a sufficiently robust evaluation, more in-depth consideration has to be given to the parameters for the abolition of the strategic reserve instrument. If the strategic reserve remains very small (which is not all that likely based on the current developments), only existing plants are recorded and the 'no way back' approach can be maintained even after the instrument's abolition ('never go back'), the consequences of an abolition would be minimal if constellations came about in the energy-only market that guaranteed sufficient contribution margins for the maintenance of security of supply. If, however, one or more of these prerequisites are not necessarily the case, an abolition would cause a system shock here too, e.g. if a sizeable proportion of the capacities of new plants could, for legal or political reasons, move from the specified strategic reserve to the energy-only market in the event of this instrument being abolished.

In terms of reversibility, the focused capacity markets model is probably the most robust option. Existing plants under threat of decommissioning are handled separately. If the threat of decommissioning were to dissipate, this would result in a price close to zero in the auction, thereby giving an empirically proven signal of the necessity of capacity payments. There is also no change in the situation if the capacity payments over multiple years are secured for new plants. If, then, the energy-only market proves to be sufficiently efficient in the long term in contrast to the fundamental assessment presented in this study, the abolition of the focused capacity market would not trigger a system shock that would seriously stand in the way of such a reversal of the capacity instrument.

6.4 Costs, distribution effects and efficiency

Just like the energy-only market, all of the capacity instruments have distribution effects. On the one hand, these are effects between the producers and the consumers and, on the other hand, effects between the various producers. However, distribution effects induced by political instruments are anything but a new phenomenon in the electricity market – arrangements such as the free allocation of emission allowances within the EU ETS and premium payments pursuant to the Combined Heat and Power Act (KWKG) have also caused and do still cause distribution effects (with very different directional impacts).

We need to distinguish between the following mechanisms in the case of distribution effects between the producers and consumers:

- The cost of capacity payments
- The (differential) cost effects in the energy-only markets

An assessment of the distribution effects between the producers and consumers must take the net effect of both mechanisms into account, as a selective approach does not deliver meaningful results:

- Based on equal capacity requirements for the safeguarding of security of supply, comprehensive capacity markets generate the highest level of capacity payments, firstly because they apply prices to the entire power plant fleet (volume effect) and secondly because, a standardised auction results in a relatively high price based for a longer term on the capacity payments necessary for new plants (price effect). On the other hand, price peaks caused by shortages are avoided in the energy-only market.
- Strategic reserve probably generates the lowest capacity payment costs, because the segments of the power plant fleet that enjoy capacity payments will likely be limited – even though the total figure very much depends on the actual design of this capacity instrument (old plants versus new plants or a hybrid model). However, strategic reserve causes price peaks in the energy-only market – this being the purpose of the model – that apply to the entire market volume and which therefore have a considerable leverage effect, and these price peaks can soon exceed the sum of the capacity payments.
- In all probability, the focused capacity market comprises a larger capacity volume than strategic reserve, but this more than likely well below that of the comprehensive capacity market. With a differentiation between existing plant and new plant segments, the above-mentioned price effect of the comprehensive capacity market is much reduced. With comparable security of supply levels, the price effects in the energy-only market are identical to those of the comprehensive capacity market model. The net effect would therefore likely be below those of the two other models, as there would undoubtedly be inefficiencies that arise from the regulation-based splitting of the market for existing plants under threat from decommissioning and the necessary new

plants in comparison to a uniform market, but they are hardly likely to reach a level that could offset the differences in relation to the other cost components.

The situation is slightly different regarding the distribution effects between the various producers:

- With its uniform price signal for the entire electricity market, the comprehensive capacity market does not have any major distribution effects. All the producers are awarded the same additional payment.
- The creation of price peaks intended by the strategic reserve model (however they may ultimately impact the coverage of fixed costs or new investments) causes an above-average increase in the contribution margins of the power plants in operation at the time of these price peaks, including those with very good fixed cost coverage, thereby boosting the corresponding distribution effects.
- In the case of the focused capacity market, distribution effects arise above all between the power plants that qualify for participation in both auction segments or that are successful in these auctions and the power plants that are not so lucky to enjoy capacity payments.

Ultimately, then, considering the distribution effects of the various models, more of a political assessment is needed of how the distribution effects between the producers and consumers (in other words, the effects on the electricity prices) and the distribution effects between the producers (in other words, the variations in profit margins in the market) are to be weighted. In addition, the individual effects very much depend on the exact parametrisation of the various models and on the energy industry and climate and energy policy parameters for the electricity market as a whole. Further analysis is needed in this respect.

This also fundamentally applies to the evaluation of (macroeconomic) efficiency, which initially overlooks distribution effects and focuses on optimising the system costs. The static efficiency (at a given point in time) is comparatively easy to model and evaluate. As far as dynamic efficiency is concerned, in other words the optimum system costs over time, the evaluation is heavily dependent on the assumptions and expectations regarding the economic and political parameters and on the specification and parametrisation of the capacity instruments. However, theoretical deliberations (EWI 2012) suggest that operation and investment decisions that take into account the shortage signals of the energy-only and the capacity market and that above all directly address the demand side lead to results that are more beneficial in the light of dynamic efficiency. In view of this, there can therefore certainly be efficiency advantages not only for the comprehensive capacity market, but also for the focused capacity market.

Finally, however, it should be noted that, for various reasons, it is difficult if not impossible to identify reliable evidence of real efficiency advantages (DICE 2011a).

6.5 Learning aptitude and the contribution made to restructuring the power supply system

Finally, thought needs to be given to the extent to which the capacity instrument is able to learn and evolve, and the contributions it can make to restructuring the power supply system.

The learning aptitude of the various capacity instruments goes hand in hand with their potential contributions to restructuring the power supply system in favour of renewable energies. Among other things in the light of the underlying approach of ‘one goal – one instrument’, the strategic reserve and comprehensive capacity market models are designed exclusively with security of supply in mind. The challenges in relation to safeguarding flexibility in power supply systems with a high proportion of variable renewables and regarding the accumulation or maintenance of a carbon-intensive capital stock are therefore delegated to the spheres of action of other instruments. This may be perfectly legitimate as far as individual aspects are concerned, but the restrictions that are caused by a very broadly differentiated and highly interactive instrument portfolio also have to be taken into account.[29]

In contrast, the focused capacity markets model explicitly incorporates the challenges relating to the flexibility requirements of new power plants and the climate policy restrictions of new-build plants, and addresses these issues with comparatively straightforward regulations. This capacity instrument therefore represents a solution which is compatible with the concept of capability markets (RAP 2012).

Seen as a whole, the focused capacity markets instrument has a large number of design effects and therefore has more in common with the model of comprehensive capacity markets, while also endeavouring to incorporate various regulatory advantages of the strategic reserve model. Considering the various dimensions of analysis discussed from a qualitative perspective here, the focused capacity markets model generally occupies a very positive position on the spectrum of models.

Nonetheless, there is a need for further, more in-depth comparison of the models on the basis of the same specifications and parametrisation for the individual capacity instruments. It would also be prudent and necessary to engage in more in-depth discussions regarding the necessity and possibility of harmonisation/coordination at least among the countries covered by the Continental European regional markets. After all, there are a whole host of legal and administrative issues that need to be clarified.

In addition to justifying and giving the specifications of a focused capacity market model, this analysis also provides starting points for the three development areas

[29] At this juncture, it is worth remembering the countervailing effects that can arise on the one hand due to the endeavour to activate the potential of manageable loads using individual instruments and on the other hand because of the compensation of electricity costs (e.g. exemption from grid utilisation fees in the event of high annual capacity utilisation levels). For more information of this problem as a whole, cf. Matthes (2010).

discussed and can therefore perhaps make a contribution to or help to expedite the debates that are needed in this respect.

7 References

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