Flexibility in the electricity system

Status quo, obstacles and
approaches for a better use of flexibility

Discussion paper

Translation of German version published in April 2017

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Preface

Flexibility has now become a byword for the electricity system. In this latest paper the Bundesnetzagentur again takes up the energy sector debate, which has so far been addressed in the discussion papers on network tariffs and on the smart grid and smart market, in order to structure the debate and highlight some of the key points from a regulatory perspective.

We are not using this as an opportunity to announce future regulatory policy but instead would prefer to enter into a discussion with the network operators and the market participants. This will only be possible if the Bundesnetzagentur's current view of this topic is known.

The paper is clearly laid out and deals individually with the situation today, especially the current and anticipated future legal situation, and approaches that could be considered for the future legal framework.

Many of the key propositions put forward in the paper will be of no great surprise given the previous opinions expressed by the Bundesnetzagentur. However, as these propositions are indispensable for a functioning energy market and a successful energy transition, they bear repeating very clearly. This includes adhering firmly to competitive solutions, which respond to price signals coming from the market, and the explicit refusal to grant specific support to individual players in the electricity market.

At the same time, the Bundesnetzagentur is open to a discussion on whether and to what extent network operators should take the scarcity of network resources into account and should be enabled to reflect these scarcities through improved tariff structures.

In nearly every case, network expansion remains the most viable solution for a volatile energy system that should combine low CO2 emissions, and eventually zero CO2 emissions, from electricity generation with security of supply and affordable prices. We are still some way from the threshold at which the question becomes more pointed as to whether a 100% infrastructural expansion would make sense. Regardless of this, there will always be phases in individual networks when the transportation capacity is insufficient, or when network expansion is so reduced by peak shaving, that it provides the network operator with the necessary latitude to pursue an orderly planning and network expansion concept.

For any of these scenarios the network operator needs a flexibility tool box from which he can choose the most appropriate tool at any given time. Producers (curtailment of renewable facilities and conventional plants), storage and loads can equally offer flexibility that benefits the grid. In this respect, the anticipated flexibility requirement is linked to the specific existence of congestion and should not be overstated; otherwise this will scarcely give rise to an independent future market. Nor would this be desirable because for some players this might give rise to an interest in retaining network congestion.

Nevertheless, the Bundesnetzagentur has drawn two conclusions from its findings:

1. For the network operator to be offered the most favourable options by the players, it is worth discussing whether, instead of restricting the network operator to a mere reimbursement of expenses, he should be allowed payment of a negotiated charge.

2. The network operator should always be guided by whatever the most favourable option is. To this end, it is necessary for all flexibility measures – more specifically the ones that incur current outlay costs for the network operator – to be included in any benchmarking under the Incentive Regulation Ordinance (Anreizregulierungsverordnung – ARegV). If this is implemented consistently, this will periodically lead to the network operator foregoing any curtailment of renewable facilities where doable. As curtailment of these facilities is frequently the most expensive option for the network operator amongst the applicable requirements of the Renewable Energy Sources Act (Erneuerbare-Energien-Gesetz – EEG). The Bundesnetzagentur proposes not only to keep these economic general conditions but to strengthen them by means of appropriate balancing obligations.

The Bundesnetzagentur's discussion proposals require specific general conditions for the proposals to be feasible and promising. These include stronger unbundling rules and a distinctly higher level of transparency regarding network situations and the flexibility instruments needed and used. The not so rare scenario in which a network area, a network operator, a dominant electricity supplier and a dominant electricity producer belong to the same enterprise, would make it very easy to gain a profit from maintaining a congestion situation if there were no unbundling or no disclosure of all technical and economic details or even no formal legal infringements. This would not serve the energy transition.

The opposite also applies: An independent network operator may take on an important role in a digitalised energy world if, through transparent, clear and neutral behaviour, he organises fair access to the energy infrastructure for numerous new players from a wide variety of sectors.

The success of the energy transition is both the immediate reason for and the long-term goal of the general conditions for flexibility instruments put forward for discussion. This discussion can and must be held rationally and constructively. There is no reason to jump to the conclusion that, simply because the Bundesnetzagentur invites participation in a discussion, there is an acute shortage of flexibility. On the contrary: sufficient and very affordable flexibility is available. There is no need for sovereign intervention measures by way of taxation in order to achieve more flexibility in the short-term or to promote very specific flexibility technologies long-term. There is a need for an objective discussion, one that is not influenced by self-interest, on how a level playing field for market solutions can be created for the long-term flexibility required and for which the best competitive option can prevail.

I look forward to a lively and thought-provoking discussion.

10 theses on flexibility in a future energy system

1. The single, liberalised European electricity market offers non-discriminatory and liquid access for all market players.
2. The electricity price is the central allocation signal for generation and demand on the electricity market. The requirement for coordination increases with more decentralised generation and increasing flexibility due to the development of RES.
3. The less additional price components distort the electricity price signal, the closer the market outcome gets to an efficient market outcome.
4. The demand for flexibility is being provided exclusively by market players. None of the players, including storage operators, should be granted any specific subsidies as this would distort the market outcome and increase system inefficiency.
5. The electricity price reflects scarcities in the generation market. In contrast, network tariffs should reflect the cost for using the network infrastructure. The interaction of both scarcity signals should induce the reaction and behaviour of the generation and demand side.
6. As the resource network infrastructure is scarce and will remain scarce, a further developed network tariff design should contribute to a secure and efficient usage of the infrastructure. Adjustments to the tariff design should be easy to administer and must not hamper non-discriminatory competition.
7. In an electricity system with more than a 50% share of RES, an active congestion management becomes increasingly important. In managing network congestion actively, the network operator can make contractual arrangements with market players that benefit the network and negotiate the payment.
8. Curtailment of RES is a flexibility option. In the case of network congestion, curtailment should be available to network operators when this is the less costly option available.
9. All flexibility options that benefit the network including curtailment should be classified as yellow phase in the traffic light concept. Under the incentive regulation scheme, all expenditure on flexibility that benefits the network feeds into the benchmarking in order to create a level playing field of incentives.
10. It is a mandatory precondition that interaction with market players is non-discriminatory, in line with unbundling and transparency..

1 Motivation and background

When talking about the energy transition, we often hear about the increasing need for the use of flexibility to be able to ensure the security of supply. The term flexibility can mean many different things. This paper aims to help structure the discussion about flexibility.

The precondition for a secure supply of electricity is in the first instance a balance of electricity generation and consumption at all times. This balance is ensured through the electricity market. In the past, it was primarily the load to be met that was unplannable and unpredictable. In the wake of the energy transition, however, variable and intermittent generation from renewable energy sources is becoming increasingly important. In the medium term, more than half of the electricity generated is expected to come from renewables. This means that conventional electricity generation will need to be tailored more to the residual load. The residual load can be defined as the amount of electricity consumed minus the amount generated from renewable sources. As the percentage of renewables in the electricity mix rises, the residual load can frequently decrease to almost zero and then increase significantly within a short window of time – either days or hours. The actors in the system therefore need more flexibility to be able to efficiently guarantee security of supply. This flexibility includes interactions with our electrical neighbours. Imports and exports at cross-border interconnectors are an essential element of a flexible energy system.

Flexibility can be defined in this context as follows:

"On an individual level flexibility is the modification of generation injection and/or consumption patterns in reaction to an external signal (price signal or activation) in order to provide a service within the energy system. The parameters used to characterise flexibility include the amount of power modulation, the duration, the rate of change, the response time, the location etc" (see Eurelectric, 2014).

Which related trends can be seen in the electricity system? We have taken the years 2015 and 2025 and identified the following trends:

1.
The Bundesnetzagentur calculated the hour-to-hour changes in feed-in from renewables for these two years.[1] The results are shown in Figure 1.

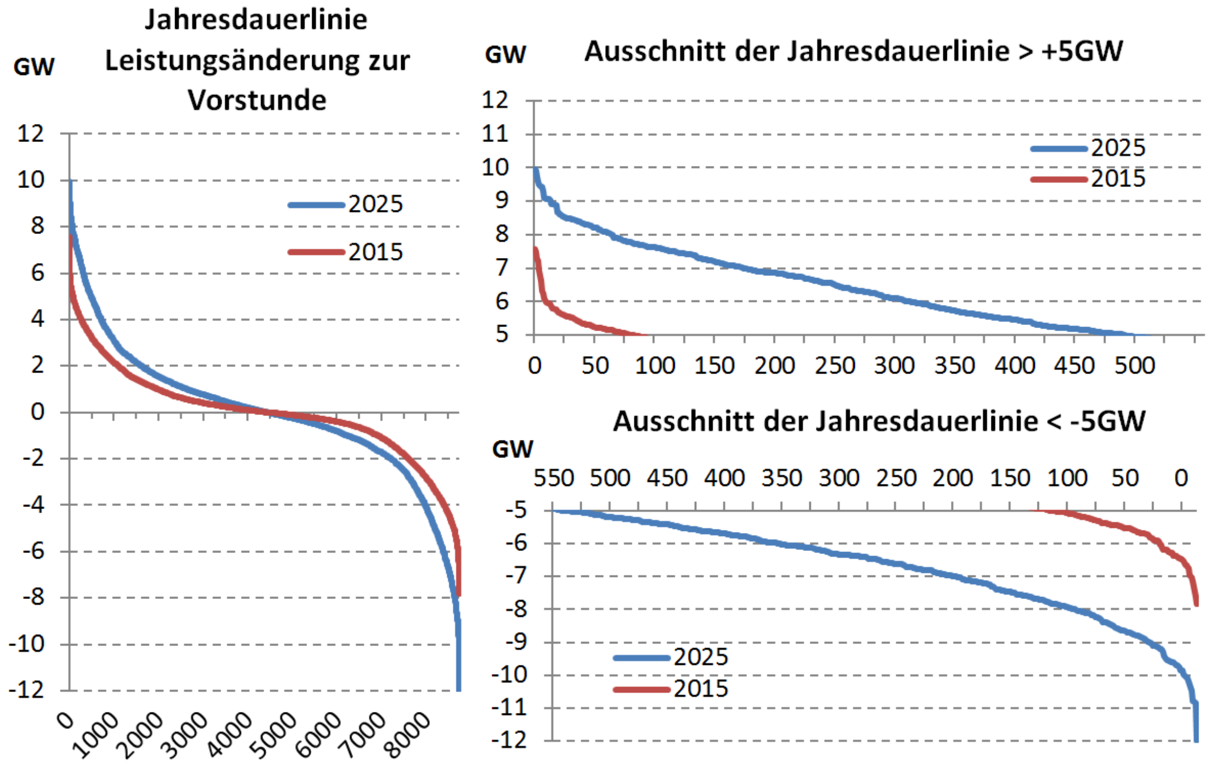

Figure 1: Hour-to-hour changes in feed-in
Source: Bundesnetzagentur calculations based on the Network Development Plan 2025 and generation data published on the ENTSO-E Transparency Platform.

The two lines in the graph on the left show the hour-by-hour changes in renewable feed-in in 2015 and 2025. The graphs on the right show an enlarged view of the upper and lower parts of the lines on the left that indicate changes (increases and decreases) in feed-in of at least 5 GW.

The graphs show that in 2015 total feed-in from the three intermittent renewable energy sources (onshore wind, offshore wind and solar PV) changed hour-to-hour by more than 5 GW in about 200 hours, with around half being increases and half decreases. In ten years' time (2025), however, the number of hours in which feed-in will change hour-to-hour by more than 5 GW will be about 1,000. In other words, within just ten years there will be a fivefold increase in the number of hours with a rapid change in feed-in of more than 5 GW.

[1] Source: Bundesnetzagentur calculations based on the Network Development Plan 2025 and generation data published on the ENTSO-E Transparency Platform

2.
The Bundesnetzagentur then looked at the scope of the changes between two extreme values, in this case the lowest feed-in and the highest feed-in within a certain period of time. The change between two extreme values normally takes several hours and is referred to here as an event. This section looks at the frequency of such events with an overall change – either an increase or a decrease – of 20 GW or more and 30 GW or more.

In 2015, there were just 15 events with a change of 30 GW or more (Ø 33 GW), while in ten years' time there are expected to be around 190 (Ø 37 GW). In 2015, there were about 180 events with a change of 20 GW or more (Ø 23 GW), and in ten years' time there will be around 420 (Ø 30 GW).

The continued expansion of renewables will lead to an increase in the absolute changes (ie the difference between the two extreme values) and in the frequency of events, but the average duration of the events will remain the same at about 11 hours. This means that the changes will be quicker. The whole system will therefore need to adapt to accommodate bigger and quicker changes in feed-in.

Does this mean that there will also be a greater need for the use of flexibility in the electricity market? And that additional measures will need to be taken to access new sources of flexibility?

The need for more flexibility could be reflected in, for instance, the electricity prices. Prices during periods of low renewable generation would need to be high and prices during periods of surplus generation low, since suppliers and consumers show little or no response to the price signals. Electricity prices would need to become more volatile to reflect the level of renewable feed-in.

In the last few years since the strong expansion of renewables (starting in 2010), at least, the growing proportion of renewables has yet to trigger any notable increase in price volatility. At the same time, the wholesale prices have fallen.

Figure 2: Day-ahead prices: 2004-2015
Source: Bundesnetzagentur calculations, EEX data

At present, the market seems to be able to compensate for the fluctuations in generation using the flexibility options currently available, such as the flexible operation of conventional power plants, imports and exports, and storage. The price signal must be able to take its full effect so as to enable the market to match supply and demand at all times even in a future system with a considerably higher proportion of renewables. Technology neutrality and the creation of a level playing field are needed for the competitive provision of flexibility by both generators and consumers. Intervention in the market in the form of new funding instruments would, by contrast, be counterproductive.

Yet market behaviour cannot be realised without the electricity grid. A uniform electricity market requires adequate network infrastructures since the infrastructures must be able to reproduce the – national and uniform – market outcome. Here, extensive investment is required at both transmission and distribution level to ensure that the networks still have sufficient transport capacity even in a system with a high proportion of renewables. At transmission level, expansion of the grid up to the level set out in the Federal Requirements Plan Act (Bundesbedarfsplangesetz – BBPlG) requires an investment of around €30bn (including €5bn for the basic network, as provided for in the Power Grid Expansion Act (Energieleitungsausbaugesetz – EnLAG), for example). This includes full underground cabling for high voltage direct current (HVDC) lines and 20% underground cabling for the alternating current (AC) pilot projects earmarked in the Federal Requirements Plan Act. The distribution networks study conducted for the Federal Ministry for Economic Affairs and Energy indicates the investment required at distribution level and puts the costs for expansion up to 2032 at between €23bn and €49bn, depending on scenario. The scenarios in the study were, however, based on the expansion targets used for the 2014 version of the EEG as well as higher goals set by the federal states. With the most recent amendments to the Renewable Energy Sources Act, the costs are more likely to be at the lower end of the scale.

However, in the future situations may increasingly occur where existing network infrastructures are not sufficient to provide the required transport capacity. The reasons for this include the steady growth in renewables, increasingly intensive interactions with other countries, the increase and decrease in conventional generation capacity, and the response of the market actors to intermittent generation. Here, grid expansion is the first choice. If the required network infrastructure is not available either temporarily or permanently, there will be congestion at transmission and distribution level.

This can already be seen for instance in the continual increase in the volumes redispatched in the transmission network. In 2015, a total of 16 TWh was redispatched, compared to around 5.2 TWh in 2014, an increase of 200%. Redispatch is nothing other than the use of flexibility by the transmission system operators for the network. The same is true for feed-in management measures. The volume of curtailed energy from all renewable sources more than tripled between 2014 and 2015. In 2015, the total volume of energy curtailed was 4.7 TWh, with around 11% due to congestion relief in the distribution network[2].

Congestion at distribution level varies considerably, depending on voltage level, growth in renewables and load. The expansion of one larger-scale wind farm with a relatively low load and only limited capacity to feed back electricity into the upstream network, for instance, can cause considerable problems in individual areas of a distribution network if, in these areas and within just a few years or even months, there are significant shifts in the rate of change in feed-in and consumption and in the period of time within which feed-in changes. There is only limited scope in comparatively small network areas for temporal or geographical

[2] See Monitoring Reports 2015 and 2016.

balancing or smoothing effects. Network operators will then have a significantly greater need for the use of flexibility for the distribution networks affected.

Yet how can network operators manage congestion efficiently under these conditions so as to be able to meet their supply commitments at all times?

Flexible behaviour can help to relieve congested parts of the network. This can then be referred to as procuring "flexibility that benefits the grid from third parties in the interest of the grid to manage congestion". At present, practically the only source of such "grid flexibility" is generation, but loads and storage could potentially play a role as providers. It is the network operators who procure this flexibility. In the sense of Eurelectric's definition, therefore, network operators can also give the signals for flexible behaviour in that they trigger a change in other market actors' behaviour in the interest of the grid.

This raises complex regulatory questions – in particular at distribution level – requiring viable answers. The first question is how much scope do the distribution system operators have in procuring grid flexibility in the market to manage congestion and what are the accompanying conditions.

This question is particularly relevant since the distribution network is a level in the value chain that is subject to regulatory conditions because of the monopoly situation. By contrast, generators, loads and storage providers are actors in a competitive environment. Interactions between the regulated level and competitive actors in the interest of the grid should be given particular attention.

This paper is shaped around the following key questions:

- Which areas of the electricity system need flexibility? (Chapter 2)
- What are the barriers for providers of flexibility? (Chapter 3)
- How can new flexibility sources be better accessed and what are the accompanying conditions? (Chapter 4)

In answering these questions, a distinction is made between the use of flexibility in the market and in the network. This distinction is due to the different competitive, technical and, ultimately, regulatory conditions.

This paper does not aim to actually define specific flexibility requirements for certain segments of the energy sector. The aim is not to create a priori scenarios for the use of flexibility. The use of flexibility is not an end in itself, nor will any need for flexibility remain at a constant level. Rather, the need for flexibility will change alongside the framework conditions in the electricity system.

Chapter 5 contains a summary of the paper. The conclusions are summarised in the "Ten theses on flexibility in a future electricity system".

2 Making the electricity system more flexible

Secure operation of the electricity system depends on one key condition: generation and consumption must be in balance at all times. Imbalances between generation and consumption lead to deviations in the grid frequency of 50 hertz, which pose a direct risk to the stability of the system.

The electricity system therefore needs to guarantee a continuous balance between generation and consumption on the market side by adapting the amount of electricity fed into and taken off the system. This in turn requires the provision of flexibility in the electricity trading and balancing markets.

2.1 Flexibility in the electricity market

To ensure that generation and consumption in an electricity system is always in balance, clear rules have been established for the electricity market, requiring balance responsible parties to manage their balancing group systems. All balance responsible parties are required to uphold their balancing group commitments, ie to balance feed-in and consumption in their balancing group on a 15-minute basis. The contractual requirement to uphold balancing group commitments is accompanied by economic incentives to achieve this balance and to act at least so as not to harm the system. The balancing system has "symmetrical" balancing energy prices because of the high liquidity in the electricity market.

The balancing group system requires and also incentivises balancing groups to be actively managed, ie generation and consumption to be adapted to the framework conditions. If it is expected that a relatively big demand (high load) will be met with only a limited supply of electricity (slack), there will be an overall increase in the price of electricity in the wholesale market. Consequently, generators may produce more electricity or consumers may use less electricity than planned. Starting out from the balancing group system, the electricity price signal develops as a result of the interplay between national and international futures, day-ahead and intraday markets.

The prices achievable in the market actors' trading contracts decide which generators provide the electricity and which consumers use the electricity. The electricity market thus ensures an efficient allocation of supply and demand. The dynamic in the electricity market – resulting from the continuous changes in both electricity consumption and generation – is particularly important. Changes in electricity demand and supply lead to an increase in the volatility of the residual load. The residual load is the proportion of the total load not met by generation from renewable energy sources. The residual load must be met by flexible and non-intermittent conventional generation plants. There is therefore an increased need for flexibility in the electricity system in the context of the energy transition.

Inflexible behaviour will become increasingly expensive for generators and potentially for consumers and their suppliers, too.

It may become expensive for generators if they are unable to reduce generation in response to low or even negative prices and thus generation costs are not covered by the electricity price over more or less long periods of time. On the other hand, consumers without flexible demand are unable to shift their consumption to cheaper times to avoid temporarily high prices. Their lack of flexibility makes them – and their electricity suppliers – unable to take advantage of potential cost savings. In extreme cases, industrial customers may pay more for the electricity they use than the added value they achieve from their production process. In the long term, flexibility therefore becomes a key factor for a low-cost supply of electricity. To ensure effective coordination, the signal for generators and consumers from the electricity market must ideally be undistorted.

Flexible generators and consumers are able not only to offer their services in the wholesale electricity market but also to market their services in the balancing markets. Balancing capacity serves as a short-term measure to correct imbalances between generation and consumption that are caused, for instance, by unexpected power plant outages or deviations from renewable energy generation forecasts. The balancing market has therefore always had high flexibility requirements. Plants providing balancing capacity must be able to adapt their output comparatively quickly.

Generation plants providing balancing capacity must operate at least at part capacity, regardless of whether or not their balancing capacity is actually deployed. Plants providing positive balancing energy operate at a level determined by their technical minimum generation level. Plants providing negative balancing energy must, by contrast, operate at a very high level so that they can decrease output as required. The opposite applies to loads: positive balancing energy is provided by decreasing consumption at short notice while negative balancing energy is provided by increasing low consumption at short notice (eg by increasing production or generating electrical heat). Transmission system operators procure balancing capacity through a competitive tendering process.

2.2 Flexibility in the grid

Market behaviour cannot be realised without the electricity grid. The network infrastructure must be able to reproduce the market outcome, otherwise network operators will need to intervene. The increase in renewable feed-in, the rise in imports and exports and above all the slow rate of grid expansion mean that the electricity networks are increasingly being stretched to their limits. The use of grid flexibility to manage congestion helps to reduce the pressure on the networks and make the market outcome achievable.

Yet exactly what shape will these measures take and how will they fit into the overall strategy for expanding the grid? And which other conditions will define the network operators' scope of action?

To answer these questions, we need to look at how the network is dimensioned. We can then go on to look at how congestion management works, with the aim of identifying specific scenarios for the use of grid flexibility.

Whether and to what extent grid flexibility can be used will depend on the voltage level requiring congestion management measures, the generation and load conditions in a certain network area, and how far the transmission and distribution system operators' area of responsibility is affected. The fact that 97% of renewable generators are connected at distribution level is of only secondary importance here, since this has always been the case for the loads. In addition, the generation and load structures in the individual network areas vary widely, and so the need for grid flexibility to manage congestion may also vary widely.

2.2.1 Dimensioning the network

The network expansion measures required at transmission level are determined in complex procedures (scenario frameworks, network development planning) and realised by the transmission system operators through the BBPlG and the Grid Expansion Acceleration Act (Netzausbaubeschleunigungsgesetz – NABEG). The Bundesnetzagentur has been given comprehensive responsibilities in this process. The network development plans set out the grid expansion measures seen by the transmission system operators as necessary over the next few years. The Bundesnetzagentur then reviews the proposed measures and confirms those that are necessary for the secure and reliable operation of the grid. The measures form the basis for the Federal Requirements Plan and, subsequently, the Act. All the network expansion plans drawn up by the transmission system operators are based on the assumption that line expansion is not designed for peaks in generation or trading that may occur for only a few hours a year. This means that even if all the measures set out in the network development plan are implemented, the transmission network will still not be able to manage without grid flexibility. In extreme load situations, flexibility services such as redispatch will still be needed to a certain extent to ensure the stability of the network. Until grid expansion is completed, measures such as redispatch will be needed to a very considerable extent to enable the market outcome to be reproduced despite congestion in the networks.

In the past, the criterion for dimensioning distribution networks was that it must be possible to fully realise market activities. The specific use of grid flexibility to increase network capacity has not yet become established in practice. Up until now, grid flexibility has only been specifically used in distribution networks in connection with charging night storage heaters. These heaters traditionally charge up following a signal from the network operators and in return benefit from cheaper electricity rates. Suppliers use a standard load profile for their customers. Otherwise, network capacity would not be sufficient even today for the networks to enable active demand side management with night storage heating systems at any time.

Specific savings potential in network expansion was identified for the first time in the distribution networks study conducted for the Federal Ministry for Economic Affairs and Energy. The study concludes that the annual additional costs of integrating renewables into distribution networks can be significantly reduced by using intelligent network technologies (the study looked at the use of controllable local grid transformers) and taking account of what is known as "peak shaving". The need for expansion driven specifically by the growth in renewables, when considered across all voltage levels (high, medium and low) as a whole, could then be significantly reduced.

The legislature gave concrete form to the concept of peak shaving in the Electricity Market Act (Strommarktgesetz) passed in July 2016. The concept allows operators of electricity supply networks to assume in their planning – for a needs-based, economically reasonable expansion of the networks – a possible reduction of up to 3% in the expected amount of electricity generated annually by each onshore wind or solar installation directly connected to their networks. At distribution level, the principle thus also applies that line expansion is not to be designed for particular peaks in generation or trading. Since around 97% of renewable generators are or will be connected at distribution level, it is an instrument for distribution system operators. It is in turn the transmission system operators' task when drawing up the network development plan to take account of the effects of peak shaving in their grid expansion scenarios.

Peak shaving opens up the opportunity for distribution system operators to design their networks no longer to accommodate feed-in down to the very last kilowatt hour of electricity generated, but in a way that makes good sense in terms of the energy policy goals of the Energy Industry Act (Energiewirtschaftsgesetz – EnWG) and the EEG. It ultimately means that they can postpone or even completely avoid expanding their existing lines. Operators can reliably take account of peak shaving in their network planning and connect more installations without first having to expand their networks. It is up to the operators whether or not they actually take up this opportunity. At the same time, peak shaving is a good solution in particular in network areas where there is already a large number of renewable installations and where the number is expected to grow.

The aim of peak shaving – however the concept is implemented – is to achieve the best outcome economically when dimensioning the networks. This approach is new and differs from the current aim of expanding the distribution networks to fully realise the market outcome.

The network operators' scope to optimise their network planning can be increased further through other instruments over and above peak shaving. As the distribution networks study shows, intelligent network technologies can provide a less expensive alternative to conventional "copper" solutions for operators expanding their networks. Network operators could also conceivably turn to other alternatives that are less expensive but equally as good as copper solutions, for example by taking account of contracting storage or loads in their long-term network plans and using them as an effective alternative to network expansion. Economic viability should be the guiding factor for the network operators when optimising their plans. If alternatives to network expansion provide a less expensive solution, they must be rewarded by the incentives in the incentive regulation scheme. This paper does not, however, deal further with whether incentives for less expensive network expansion should be created and the consequences this would have. Rather, this paper deals with the challenges that arise when network expansion is delayed or not possible or is implemented on a smaller scale.

Assuming that the existing or planned capacity of the electricity grid is temporarily not sufficient to transport the actual amount of electricity generated, the following conclusions can be made.

It will be necessary for network operators to take operative measures to manage network security if network expansion has not yet reached the planned level. In this case, measures would only need to be taken over a certain period of time. These measures are taken according to the congestion management concept described in Chapter 2.2.2.

In addition, network operators may (increasingly) need to take operative measures on a permanent basis if they have chosen not to dimension their networks to fully realise market activities. These measures also form part of the concept described in Chapter 2.2.2. At the same time, despite network operators having increasingly more scope to optimise network planning, a sufficiently dimensioned distribution network will still be the rule and conventional expansion the operators' first choice.

2.2.2 Congestion management concept: the traffic lights approach

The traffic lights concept has been used in discussions about grid and market flexibility since 2011[3]. It serves to illustrate expected congestion scenarios and the countermeasures that can be taken by network operators as part of their operations management. It is also used to illustrate the greater involvement of market actors in resolving network congestion at distribution level. It must be borne in mind, however, that it only makes sense to apply the traffic lights concept to one specific network segment as defined by the operator according to technical and economic criteria. This can therefore involve a very large number of small segments: according to the distribution networks study, Germany has around 500,000 low voltage, 4,500 medium voltage

[3] For instance in the Bundesnetzagentur's position paper on smart grids and smart markets.

and 100 high voltage networks, each of which could be constrained and would then require temporary or permanent congestion management.

The measures are classified with reference to the legislative provisions of section 13 EnWG:

All market actors can realise their plans; at the most, network-related measures according to section 13(1) para 1 EnWG are required	Green
Market-related measures according to section 13(1) para 2 EnWG	Yellow
Measures according to section 13(2) EnWG and measures according to section 13(2) EnWG in conjunction with section 14 EEG (feed-in management)	Red

Figure 3: Traffic lights – classification according to the legislative provisions of section 13 EnWG
Source: Bundesnetzagentur

In the green phase, all the market actors can realise their plans. No constraints are imposed by the network operators. This is the ideal situation and should be the goal.

If network operators find that they cannot resolve network problems using their own operational resources, they exit the green phase. The network operators enter the yellow phase and take "market-related" measures (section 13(1) para 2 EnWG). These market-related measures include increasing or reducing generation from conventional power plants (redispatch) or using contractually agreed load reductions or increases (that under current legislation, however, may only be contracted under certain conditions).

If a threat or disruption cannot be removed by the measures according to section 13(1) para 2 EnWG and all the market-related measures available have been exhausted, the network operators are obliged to take measures according to section 13(2) EnWG. In this red traffic lights phase, operators may prevent (or increase) feed-in from conventional generation plants and even renewable installations or offtake from loads without prior agreement or consultation and without compensation.

In the event of network congestion, section 13(2) EnWG in conjunction with section 14 EEG (feed-in management) applies to installations subject to the EEG or the Combined Heat and Power Act (Kraft-Wärme-Kopplungsgesetz – KWKG). In other words: in the event of network congestion, feed-in from these installations may also be prevented or reduced, but only in a second step after conventional power plants and in return for compensation as specified by law (section 15 EEG).

As shown above, the measures provided for by section 13 EnWG have an order of priority established in the legislation. What does this mean in operative terms? Network operators may only take red phase measures if green and yellow phase measures will not be sufficient. This does not mean that network operators are forced to run feed-in management measures "bis sight" solely as a process based on actual data. The provisions on priority access for renewables and the order of priority of measures according to sections 13 and 14 EnWG in conjunction with sections 11 and 14 EEG and/or section 3 KWKG do not rule out planning and implementing feed-in management measures in a process based on forecast data as applied for redispatch. The network operators should have suitable processes based on forecast data and using data and typical figures that can be collected in advance to pre-estimate with sufficient certainty at least the minimum amount of feed-in management required.

According to section 13 EnWG, the order of priority of measures to manage network congestion as established in legislation is intended for transmission system operators. According to section 14(1) EnWG, the provisions apply accordingly to distribution system operators provided that the operators themselves are responsible for security and reliability in their networks.

How does feed-in management at distribution level actually work?

Practically no redispatch measures are taken at distribution level since there is very limited potential for redispatch in the distribution networks. At distribution level, almost the only measures taken in the event of network congestion are measures such as feed-in management. Feed-in management is frequently the first choice in particular for operators of distribution networks with a high level of renewable feed-in. The introduction of peak shaving may also mean that feed-in management measures will be required on a wide scale and on a permanent basis. In the event of congestion, operators therefore switch directly from the green to the red phase

The reason for this is that at present there are hardly any market-related measures available or incentives for network operators to take such measures. We must therefore ask whether and in what way more efficient congestion management would be possible at distribution level if additional potential for market-related measures were created through additional incentives and accompanying conditions. Chapter 3.5 discusses potential barriers to a more active use of market-related measures in the yellow phase. Chapter 4.2 outlines possible solutions.

3 Barriers to flexibility

The rules on the organisation of the electricity market, the promotion of renewable and conventional electricity generation, and the arrangements governing the regulation of costs and the network tariff system have a considerable affect on economic efficiency and therefore also on the use of flexibility. The organisation of the electricity market may hinder the development of flexibility on the supply or demand side.

Basically, flexibility will only be used and investment in flexibility will only occur, if the potential revenues exceed the costs. Therefore, in this connection, it is possible that slight price differences will be frequently exploited by low-cost flexibility whereas high-cost flexibility will be dependent on high price differences, with the latter only occurring infrequently. Overall, it is essential that there is no restriction on price setting as provided for in the Electricity Market Act (Strommarktgesetz). The following sections (3.1. to 3.3) detail where it is difficult to use flexibility in practice due to the barriers caused by the electricity market organisation.

A clear distinction has to be made between the rules on the electricity market organisation giving rise to its inherent barriers and the issues that arise because of the network infrastructure. The use of the network should be designed to be economically efficient and any disproportionate burden on the network user should be avoided. To this end, network operators should make use of opportunities to develop solutions that enable them to perform their supply duties efficiently. Any barriers to this will be presented in detail in sections 3.4 to 3.5 and will be viewed against the necessary regulatory framework.

3.1 Barriers caused by the design of the electricity wholesale market

The rules governing the electricity wholesale markets have a significant impact on the use of flexibility. Two factors are particularly relevant here: one is the duration of the balancing period and the associated design of the trading product, and the other is the length of time between the close of trading and the time of delivery.

The regulator determines the duration of the balancing period, which in Germany amounts to 15 minutes pursuant to the Electricity Network Access Ordinance (Stromnetzzugangsverordnung – StromNZV). A balancing group's generation and consumption is balanced over a balancing period. Ideally, generation and consumption will balance out and any differences will be made available or purchased by the TSOs and accounted for at the imbalance price.

Other countries have chosen different time frames for their balancing periods, which in some cases are considerably more than 15 minutes. This would result in their being excluded from any cross-border intraday market coupling in a 15-minute time scale. The first step that needs to be taken to further market coupling is the harmonisation of balancing periods at the European level. The transition necessary would be far-reaching as the balancing period sets the time schedule by which all electricity sector processes are transacted. The EU Commission Regulation establishing a guideline on capacity allocation and congestion management (2015/1222, the "CACM Guidelines") provides for the coupling of the day-ahead and intraday markets within a tight time frame.

At the same time, the balancing period provides the framework arrangements for the electricity trading products as the duration of the balancing period ultimately determines even the "smallest fragmentation" of electricity trading products. The design of the electricity market products, however, is not prescribed in detail either in the legislation or by the regulatory authority. Rather the business operators themselves decide on the design and introduction of electricity market products by demanding those products with which they best meet their obligations under supply, purchase and balancing group agreements. The market itself can mobilise flexibility for the electricity market by making changes to the product specifications.

On the day-ahead market, for instance, hourly products are mainly traded. Hourly products, however, have to ensure continuous electricity supply for one hour or a consistent reduction in consumption, and therefore act as a barrier to the inclusion of flexibility options of time constants of less than one hour. The intraday-market, where 15-minute products are traded, is thus more important for the participation of flexibility options with shorter time constants.

One possibility to reduce the balancing energy requirement and to lessen the balancing energy risk would be to shift the close of trading for continuous intraday trade closer to the delivery time. The forecast for the generation of conventional and renewable energy, the consumption forecast and the information on taxable loads and storage availability, all improve the nearer the delivery time. Flexibility could thus be used in a more targeted manner.

3.2 Barriers caused by the design of the balancing marketes

To keep the costs of balancing energy as low as possible, flexible generation and consumption are a sensible addition to the provision of positive or negative balancing capacity from conventional power plants. They can also increase competition on the balancing market and thus contribute to cost reductions. The participation of flexible consumers in the balancing market is conditional upon their being able to offer balancing capacity reliably over the necessary time periods and upon their having appropriately satisfied the TSOs' requirements to provide balancing capacity. A high quality standard is necessary for this purpose.

At present balancing reserve is provided for the most part by conventional power plants and pumped storage units because they are reliable and relatively cost-effective. This gives rise to interactions between the balancing market and the electricity wholesale market:

Participation in the balancing market automatically restricts the respective plant or unit from marketing their electricity for the wholesale market as they have to be able to adjust their feed-in at short notice to provide balancing capacity. Suppliers of positive balancing cannot offer their total output on the wholesale market as they have to be in a position to generate additional electricity to provide balancing capacity. Moreover, depending on the technical capability, the plants must already be generating electricity at a certain level in order to render sufficient balancing capacity quickly. Therefore thermal power plants that provide negative balancing capacity cannot scale back their generation completely, even when electricity prices are low, because they have to be able to reduce their generation when called upon to provide balancing capacity. Thus those participating in the balancing market cannot fully align their generation with the market signals from the wholesale electricity market. This results in a "minimum" generation amount of conventional electricity in the wholesale electricity market. Even when there is high generation from renewable energy sources, the plants remain in operation because, as stated above, they have to be available to provide balancing capacity. This can lead to negative prices, inefficient electricity export and, through the growing contribution of renewables to overall electricity generation, to the scaling back of renewable energy installations. Consequently, the amount of the minimum conventional generation must be reduced in the medium- and long-term.

Opening up the balancing markets to new suppliers may counter the interaction problem stated above between the balancing market and the electricity wholesale market: The additional participation of new, flexible providers could lower the basic generation of conventional plants on the electricity wholesale market by replacing the conventional plants' balancing capacity reserve with that of other, more flexible providers. Possible new providers include those operating flexible loads (eg electricity-intensive industrial enterprises) and storage facilities.

The Interruptible Loads Ordinance (Verordung zu abschaltbaren Lasten - AbLaV) was an attempt to introduce high loads onto the balancing market. Pursuant to the initial ordinance, loads with a minimum reduction capacity of 50 MW, which were connected at the 110 kV level or higher, could participate in a separate call for tenders from the transmission system operators for reduced capacity. As the Bundesnetzagentur noted in its evaluation report, the outcome, however, was that the group of providers was very small and five of the six providers left the balancing market in order to benefit from the general conditions offered by the AbLaV. Due to a lack of competition and the higher compensation offered by the ordinance, the balancing market was deprived of its potential.

The amendment to the AbLaV in 2016 attempted to increase both the number of providers and the competition under the ordinance scheme by relaxing the conditions of participation. Thus the minimum reduction capacity has been changed to 10 MW, the offer period has been shortened from one month to one week and the load supply voltage has been reduced to 20 kV. At the same time, the minimum prices have been reduced. Whether this will lead to more flexible providers or, conversely, whether even more potential balancing capacity will be lost, remains to be seen.

3.3 Electricity price distortion caused by the design of support schemes

3.3.1 The support mechanism for renewable energy as a constraint on flexibility

Increasing and promoting electricity generation from renewable energy is a socially accepted objective of the climate and energy policies in Germany. The practical implementation of the scheme, however, through kilowatt-hour based compensation per MWh of electricity, inhibits flexibility in generation because it places a significant constraint on the response of renewable energy installations to actual market conditions.

In those situations where renewable input and inflexible conventional power plants meet weak demand, the electricity price can fall below zero. This is a clear market signal that in these type of situations an efficient solution would be to reduce output from renewable energy installations and feed-in from conventional power plants as well as to increase consumption. The solution that would be the most cost-effective in a specific situation should be decided by a market mechanism. This is because making conventional power flexible generates costs that have to be borne either by the owners of the conventional plants or by consumers.

In a system of fixed feed-in tariffs and marketing by the transmission system operators, however, no reaction whatsoever occurs on the part of the renewable energy installations to price signals.[4] Consequently, facilities

[4] The possibility of submitting limited bids in a second auction in the event of clear negative prices and upon request could be construed as being the transmission system operators' reaction to prices. However, this does not represent flexibility and will not be taken into consideration in this paper.

in this type of marketing system produce power irrespective of the actual market conditions. Renewable installations also do not fully react to price signals in direct sales systems with market premiums because the premium is set up as a fixed surcharge on the applicable market price at the time. Thus, the total market price and market premium, less any variable costs of the installation and direct marketer, must first become negative before the operator has an incentive to reduce generation. Consequently, electricity will still be produced from renewables even if market prices signal that any additional generation will cause economic costs. This constellation also applies to biomass. The very high energy-based support scheme means there is very little incentive for these installations to be flexible. This situation will continue for as long as support for renewables is based exclusively on the kilowatt-hour rate. The costs are then made up of negative prices.

What could be taken into consideration, though, is promoting renewable energy on the basis of a system that has a less distorting impact on deployment decisions and purchase decisions in the electricity market. For obvious reasons such a support scheme cannot be based purely on the price per kilowatt. Installations that earn money simply because they have been set up and without any production will hardly be built or used in line with efficiency criteria. Moreover, the gap between the financing of renewable energy and the financing of conventional generation would become even wider.

Consideration could be given to whether a support scheme should be based on the quantity of electricity. The Bundesnetzagentur is calling for this line of thinking to be pursued again and for a study to be conducted to carefully weigh up the benefits and disadvantages and their overall economic effect.

3.3.2 Combined heat and power (CHP) support as a barrier to flexibility

CHP plants have been installed at many municipal plants and industrial operations; they produce electricity for the electricity market or for self-production and receive energy-based entitlement to payment (known as the CHP allowance). They also benefit from avoided network tariffs. Many biomass plants are operated as CHP plants because this forms part of the requirements to qualify for the support scheme.

This support scheme is reflected in the electricity price bids made on the market by CHP plants, which show that they can offer electricity at much lower prices than other power plants. This causes a distortion in the efficient deployment of power plants: thus conventional power plants with high variable costs are operated that would not be operated without this distortion effect. There is a noticeable lack of pressure on the plants to run efficiently. Consequently, numerous gas-operated CHP plants are being operated at times when it is economically inefficient to run gas-fired power plants because of low electricity prices.

Whilst the final customer's electricity price is rising because of the CHP allowance, the average price of electricity on the wholesale market is falling. Due to the energy-based support scheme, CHP plants can still be operated even when prices are negative. Thus no use is made of the plants' technical flexibility. The technical capability of CHP plants, which is often argued in the political arena, of being able to respond flexibly to a change in requirements and of being able to scale production up or down, is without significance given the economic position of CHP plants: their revenue situation is not conducive to a price response; the direct support scheme incentives, the avoided network tariffs and the income from providing heating will be in excess of the electricity price signal practically every hour of the year. About 98 TWh/year (net), approximately 16% of German electricity consumption, are generated in CHP plants.

An attempt to encourage more flexible operation of CHP plants was made with the introduction of the so-called "use don't curtail" concept in section 13(6a) EnWG. If there is congestion in the transmission network, transmission system operators can offer contracts to CHP plants in specific congestion areas as part of redispatching. These contracts give the network operator the possibility of scaling back the CHP plant in the event of congestion. Heating is then provided using heating elements, which have been paid for by the transmission system operators and which cause additional electricity consumption to relieve congestion. This process is a first step towards the more flexible operation of CHP plants, however this is only possible due to the generous payment provided by the transmission system operators.

The provision of heating from power-to-heat plants (electricity is converted into heating, for example by way of a heating element) is an example of how flexibility can be made available within the framework of sector coupling.

3.3.3 Privileged treatment of self-consumption as a barrier to flexibility

Burdening the electricity price with energy-based levies, allowances, taxes and network tariffs, which self-consumption schemes are not subject to for the most part, makes investment in self-production plants economically efficient. The price advantage of a self-production plant, when compared to obtaining electricity from the general supply network, can be as much as 19 ct/kWh.[5] In addition to the price advantages of being exempt from network tariffs, taxes and allowances, under certain circumstances self-consumers also receive avoided network tariffs as well as entitlement to payment for CHP electricity even for self-sconsumption. The self-consumption privilege and other advantages are nearly always granted for an unlimited period; long after the complete refinancing of the plant by the general public, it is still possible to take advantage of the financial benefits, exemptions and entitlement to payment.

Many investments were made to enjoy the benefits of this favourable treatment. It was not economic sense, though, that led to investment in the energy sector, rather it was the attraction of being able to siphon off as big a share as possible of the benefits accruing out of this privilege.

At the present time these special self-consumption privileges are causing a situation where the self-production plants do not compete at all with the other generation installations on the wholesale market or, at best, compete only when the market is severely distorted with extreme prices. Self-consumers do not respond, or only in an extremely limited way, to electricity price signals and they only purchase external electricity a few hours of the year when electricity prices are extremely negative. For most hours of the year, a decision is made in favour of using self-production as the production cost of a kilowatt hour is practically always less than the cost of purchasing external electricity because of the savings in tariffs, taxes and levies.

This also leads to a loss of the coordinating function of the electricity market with respect to CO2 emissions: A self-production plant can be profitably operated in nearly every market situation even if in a comparison with the overall market it shows increased emissions caused by poor efficiency or a CO2 heavy fuel (coal). The CO2 trading effect is lost in this situation; this is also the case even if the industrial enterprises involved does not gain any advantages under the CO2 certificate system.

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[5] See Bundesnetzagentur (2015), "Self-supply Guidelines", October 2015.

A plant that operates more or less the whole year round is not concurrently available as a source of flexibility. Thus the preferential treatment enjoyed by self-production also reduces the flexibility of the generating capacity available and therefore presents another barrier to flexibility. Data on self-supply is still poor; it is estimated that 62 TWh/year, which is more than 10% of German electricity consumption, comes from self-production plants.[6]

In addition to industrial and commercial consumption, there is another class of self-production, that of the "prosumer". The term "prosumer" describes a household customer who produces their entire consumption or parts of it themselves (primarily with PV installations) without making use of the distribution network. Nevertheless, for those times that their own generation is not sufficient, the prosumer is also connected to the general supply network and hence uses the infrastructure financed by other users of the public grid. As self-produced electricity is not burdened with surcharges (in the full amount) and levies, prosumers are never tied to market price signals because self-production is always cheaper than purchasing electricity from the grid.

This effect is all the stronger as suppliers still supply prosumers on the basis of standard load profiles defined by the network operator, which are not able to adequately show the individual consumption and generation. A primary requirement for price signals to actually have an effect on household customers is if suppliers have the possibility of passing on market fluctuations to the customer whilst taking the actual consumption behaviour into consideration. To facilitate an active role for prosumers, in the future they must be equipped with an intelligent metering system with settlement every 15 minutes if they want to participate in the market as players and use their flexibility. The Energy Transition Digitisation Act facilitates this need for flexibility, in line with moving away from a standard load profile, by imposing a requirement on network operators to enable network users – insofar as this is necessary for a variable tariff – to do the settlement and billing on the basis of a counter reading if the relevant point of consumption is fitted with an intelligent metering system, section 12(4) StromNZV. In addition, commensurate with the growing importance of the prosumer, the Metering Operations Act (Messstellenbetriebsgesetz – MsbG) creates the basis for an intraday meter reading (= the measurement of electric energy in a series of meter readings every 15 minutes) at generating installations that are fitted with an intelligent metering system.

3.4 Barriers in the network tariff system

Peak loads

Network users influence the network costs and the need for additional expansion through their behaviour. Under the current tariff system it is assumed that the network costs are driven by each network user's contribution to the concurrent annual peak load. Therefore allocation of the network costs is based on each network user's individual (statistically probable) contribution to the concurrent annual peak load.

For consumers with measured load profiles that are somewhat higher, the main component in network tariffs is the capacity-based price component. The amount depends on an individual enterprise's consumption peaks over the course of a year. This presents a strong incentive for enterprises with measured load profiles to reduce their peak consumption, either through working in a more energy-efficient way or by stabilising their

[6] See Prognos (2014), "Letztverbrauch 2015 Planungsprämissen für die Berechnung der EEG-Umlage" (*Final consumption 2015 planning premises for calculating the EEG surcharge*), Berlin, 8 October 2014.

load. For example, many final consumers now perform production processes sequentially instead of in parallel so as to reduce the payment of network tariffs. This can be interpreted as activating load management potential during operations, which ultimately benefits the network.

Attempting to stabilise the load may restrict any flexible response to low market prices, the supply of negative balancing capacity or other services for network operators. This is not the case if consumption lies below the annual individual peak load. At this level, the load's response to a signal (eg electricity price or the use of balancing energy) does not cause any additional network tariffs and can therefore be realised without any further ado.

Increases in the load, however, may also cause new consumption peaks that trigger network tariffs, with the consumption peaks generally being more expensive than any potential earnings from balancing capacity or the spot markets. If high demands are placed on the network as a result of increased loads, there can be no objection to high network tariffs. On the contrary, from a network point of view it makes sense to reflect the scarcity of network resources by means of a corresponding level of tariffs. Insofar as this is not the case, that is to say, where the network is not further negatively impacted by higher loads, an adjustment to the arrangement may be considered. No easy solutions can be expected, however, because the network status is very dependent on situation and locality, and because any assessment of the room for manoeuvre is heavily susceptible to abuse and discrimination.

Nonetheless, there are a growing number of possible network situations in which an increase/decrease in the peak load is not connected to a corresponding increase/decrease in the network costs. This applies, for example, in those cases in which the size of the network is determined not only by the load but also by feed-in from renewables. There are also cases where, for historical reasons, the networks are overdimensioned so that any increase in peak loads is not reflected in the network planning requirements. In particular, the size of networks takes the contractually installed capacity as a guide, which is often higher than the final consumer's peak load of the year. Ultimately the statistically determined "probable" concurrency degree may differ from a final consumer's individual concurrency degree.

Special tariffs

According to the ordinance rationale, section 19(2) of the Electricity Network Charges Ordinance (Stromnetzentgeltverordnung – StromNEV) is designed to grant privileges to consumption behaviour that makes an individual contribution to lowering and/or avoiding network costs. This is to allow for a possible difference between the statistically determined "probable" concurrency degree possibly and a final consumer's individual concurrency degree.

A distinction is made between atypical network users as per section 19(2) first sentence StromNEV and electricity-intensive network users as per section 19(2) second sentence StromNEV. Whereas atypical network users have a peak load at historically low load network times, electricity-intensive network users have steady yet high electricity consumption.

The actual design of the special arrangements in section 19(2) StromNEV, however, prevents the use of loads in a way that benefits the system. In their current form under the amended energy sector framework conditions for the energy transition, the arrangements in section 19(2) StromNEV do not offer any appreciable benefit with respect to network integrity or reducing network costs.

The current rigidity in section 19(2) first sentence StromNEV on promoting atypical network usage is not appropriate for leveraging flexibility potential. The peak load time windows to be set by the network operators firmly stipulate a specific acceptance procedure one year in advance. Peak load time windows therefore cannot of themselves ensure an acceptance procedure that benefits the network. In some network areas the case may arise where a peak load time window occurs simultaneously with a generation peak from distributed generation (eg wind energy). In this situation an increase in withdrawal capacity could even be desirable for the network for technical reasons but this would be penalised with the loss of any claim to reduced network tariffs. At the same time, the present arrangement would be an additional barrier to synchronising consumption and generation in that it would concurrently prevent market-oriented acceptance behaviour without any justification on technical network-related grounds.

The arrangements in section 19(2) first sentence StromNEV thus describe a simplistic charging system dependent on the load and time, which is designed to encourage behaviour benefiting the grid. However, in its present design (specifying and setting the time window one year in advance, uniform reduction for all loads irrespective of the specific grid connection point or the type of feed-in), the objectives cannot be adequately achieved. In particular, in those network areas where the network size is driven by distributed feed-in this is completely ineffective as, according to the StromNEV arrangements, peak load time windows are to be based exclusively on the time of the highest offtake load of the connected network.

The arrangements in section 19(2) second sentence StromNEV, which benefit high and steady consumption behaviour, likewise foster – albeit coincidentally and dependent on the network situation – behaviour that benefits the grid and system. In times of low-demand the high consumption by electricity-intensive final consumers is usually irrelevant but at times of high demand this high level of consumption is a burden on the network.

Consumers can benefit from a considerable lowering of the network tariffs pursuant to the current section 19(2) second sentence if they achieve 7,000 hours of use per year and consume more than ten gigawatt hours of electricity per year. This creates an incentive for very even electricity consumption, irrespective of

the network or market conditions. This does mean, though, that the users will neither reduce their consumption in times of scarcity nor increase their demand at times of very low or negative electricity prices if this would cause them to be below the required number of full hours of use or gigawatt hours used for a reduction in network tariffs.
The final consumers concerned display a considerable degree of technical load flexibility. Nonetheless, instead of using this in response to the electricity market they use it in response to the StromNEV requirements as the incentives for a substantial reduction in network tariffs are significantly higher than those for the current electricity price signal. The systematic approach of section 19(2) second sentence StromNEV must therefore be viewed as virtually anti-flexibility.

3.5 Barriers to network flexibility in the incentive regulation scheme

The amendment to the Incentive Regulation Ordinance as of the third regulatory period has led to considerable changes for distribution network operators. The previous pure budgetary approach that was applicable has been changed to a system of ongoing capital expenditure true-up This means that the actual investment behaviour of the network operators is reflected on the revenue side. An annual capital expenditure (CAPEX) true-up is carried out based on actual investment and depreciation. The budget approach continues to apply to operating costs (OPEX). OPEX are incurred as an expense by the network operator and are factored into the revenue cap without any rate of return or profit markup.

When planning, expanding and managing their networks, distribution network operators make decisions that lead to the use either of greater network expansion with less need for grid flexibility or to less network expansion with a greater need for grid flexibility (for example through taking peak shaving into account when planning, which leads to further congestion management). The details of the regulation determine the direction the network operator's behaviour takes.

Against this background, two key parameters in the incentive regulation scheme were considered in this paper:

- Incentives with respect to the size of the network, which have an effect on the amount of the fixed assets or the rate of return.
- The regulatory treatment of the costs of the grid flexibility used by network operators as part of congestion management.

Distribution network operators evaluate the options while also taking account of the efficiency benchmarking provided for in the incentive regulation, which is included in the operating costs and capital costs.

The assessment base for the rate of return on equity, and thus also for the imputed rate of return, is lower if, within the operator's planning leeway, the network operator decides on a smaller size network rather than a more extensive network expansion. Efficiency benchmarking, which provides incentives to control or reduce costs, adjusts the incentive for a capital-intense investment strategy.

If a network operator decides to dimension his network smaller, there is a greater need to carry out congestion management procedures. In this case the operator incurs the cost of payments to third parties for their contribution to relieving congestion. At the present time these are essentially compensation payments for renewable energy facilities. Potentially, other options could arise here in the sense of contractual arrangements with other market players on the provision of grid flexibility (see Chapter 4.2). Of relevance here is how these costs are to be treated from a regulatory perspective.

Payments under the aforementioned "market-related" measures are allocable to operating costs and are included in the efficiency benchmarking. There is no provision for adjustment at short notice outside the base year. Compensation payments for feed-in management are likewise allocable to operating costs and can be refinanced from network tariffs in accordance with section 15 EEG insofar as the measures were necessary. Pursuant to section 11(2) sentence 17 of the ARegV, when setting the revenue cap these costs are attributed to the permanently non-controllable costs. Thus the compensation payments are not included in efficiency benchmarking. Additional curtailment, therefore, has no effect for the network operator.

Consequently, even with a choice of various flexibility options benefiting the network, a network operator wishing to make improvements from an economic perspective would not look for alternative, more efficient solutions, but instead would be guided by the classification of permanently non-controllable costs and thus would apply feed-in management measures as part of congestion management.

Overall, in current regulatory practice, the curtailment of renewable energy facilities is in every sense more attractive for the network operator than market-related measures. Incentives under the Incentive Regulation Ordinance are currently working against any possibility to fully exploit congestion management as per section 13 of the Energy Industry Act and thus represent a barrier to efficient network operation. If, in future, network operators find themselves more frequently in a situation that calls for congestion management, the unequal regulatory treatment of grid flexibility measures having similar effect will be critically relevant.

At best the regulatory system should set the incentives in such a way that the network operator aims to achieve an economically efficient mix of network expansion and flexibility in the operator's own, individual economic interests.

4 Actions to improve access to flexibility

The previous chapter discussed barriers to flexibility. Barriers exist in particular in the context of price distortions due to the design of support schemes, the current scheme for special network tariffs, which impede the use of flexibility, and the current design of the "traffic lights" concept in the distribution network and the associated recognition of costs under the incentive regulation scheme. A secure and economical electricity supply is and will remain the top priority. The electricity market 2.0 is the key instrument for a secure and low-cost electricity supply. The question as to how far the existing structures should be reconsidered must therefore always be discussed in light of the impact they have on the electricity market 2.0.

This chapter discusses and assesses possible actions that could serve to eliminate the barriers identified in the previous chapter.

4.1 Access to flexibility for thebalancing market

The Bundesnetzagentur enhanced the tendering conditions for all three types of balancing capacity back in 2011 with the aim of making it easier for additional flexible generators and consumers (for example the operators of renewable installations, flexible loads and storage facilities) to participate in the balancing markets and provide balancing capacity. Opening up the balancing markets further for new providers and thus extending the range of possibilities for providing balancing capacity can also increase competition in the balancing market, which in turn could reduce the costs of maintaining and deploying balancing capacity.

The tendering conditions and prequalification requirements should be optimised to make it easier for flexible providers to access the balancing market. More specifically, the tendering periods and intervals between tendering and the blocks for the individual products could be shortened. This could make it easier for renewable generators and flexible consumers, for example, to participate in the market, since they are better able to estimate their feed-in closer to the delivery period thanks to additional and/or up-to-date information and they would then not need to remain available over too long a period of time.

The Bundesnetzagentur is considering these points in the ongoing determination proceedings on enhancing the tendering conditions and publication requirements for secondary and tertiary balancing capacity. In particular, shortening the auctioning period for secondary and tertiary balancing capacity from the current one week or one working day to one calendar day, in conjunction with day-ahead auctions, and shortening the blocks for secondary balancing capacity could lead to more flexibility in providing balancing capacity. The Bundesnetzagentur published key elements on the subject for market consultation and also held a workshop on 13 July 2016.

In addition, the transmission system operators have reviewed their prequalification requirements for balancing capacity in light of the characteristics of flexible providers such as storage facilities and renewable installations and have drawn up new prequalification conditions for the provision of primary reserve by battery storage and for the provision of tertiary reserve by wind power plants.

Aggregation can also play an important role in the provision of secondary and tertiary balancing capacity by flexible consumers. Aggregation enables flexibilities from small and medium-sized loads that individually would not meet the requirements for providing balancing capacity to be bundled and marketed. The role of aggregators is currently taken on by suppliers acting in an effective competitive environment and competing for customers and the best problem-solving strategies. The legislature amended section 26aStromNZV to also make it easier for non-supplier aggregators to access the balancing markets in the future. In addition, the Bundesnetzagentur and the Federal Ministry for Economic Affairs and Energy initiated a dialogue between the stakeholders back at the beginning of 2016. The aim of the dialogue was to work out an industry solution for integrating non-supplier aggregators in the markets for secondary and tertiary balancing capacity. The dialogue resulted in the publication of industry guidelines at the end of 2016. In March 2017, the Bundesnetzagentur opened determination proceedings on the subject and published a key elements paper for consultation, with the aim of creating a uniform framework.

4.2 New forms of organisation for congestion managementin the distribution network

Grid expansion is also the first choice at distribution level so as to enable long-term management of an energy supply system in which more than half of the energy generated comes from renewable sources. Until expansion is completed, situations may increasingly occur where network infrastructures at distribution level will not be sufficient to provide the required transport capacity – either temporarily or owing to peak shaving. In such situations, distribution system operators will need to manage the network congestion. The current congestion management practices and associated obstacles have been presented in Chapter 2.2.

This chapter outlines possible future practices for congestion management in the distribution network. A distinction must be made between the thoughts set out below and the discussion surrounding decentralised approaches and local markets, which aim at balancing energy no longer centrally through the energy-only market (EOM) but at a lower level in locally or regionally fragmented areas (cellular models). This fragmentation cements congestion and also assumes that network congestion will remain in the long term. The approach taken in this paper assumes, by contrast, that – to sustain large liquid markets allowing non-discriminatory trading – congestion will be remedied through grid expansion. In this case, it is necessary to define congestion management practices and the role of the distribution system operators for the period until network expansion is completed. A distinction must therefore also be made between the thoughts set out in this paper and studies dealing with alternative approaches to avoid grid expansion.

The overall aim of the process should be to better integrate electricity from renewable sources into the system. It can therefore make sense to provide network operators with alternative options other than curtailing renewable energy. Congestion can also be alleviated through grid flexibility using load reductions or increases or contracting storage solutions.

An assessment of the potential use of these tools by distribution system operators depends on how far it would benefit the system as a whole and could lead to lower costs for the consumers, for instance lower network tariffs.

From the Bundesnetzagentur's viewpoint, a proactive, efficient and well-ordered procedure for congestion management by distribution system operators should be developed with a view to achieving the desired aim. The network operators should be given the relevant economic incentives. Needs-based expansion of the networks remains the first choice in order to integrate renewables into the electricity system to the highest possible degree. The framework conditions therefore need to be set so as to prevent congestion becoming artificially established. This is a necessary assumption in all approaches that reward the maintenance of flexible capacity.

A level playing field should be created for grid flexibility options in terms of how they are reflected in the regulatory framework. High requirements are also needed in respect of transparency and non-discrimination.

Load forecasts provide the basis for proactive, efficient and well-ordered congestion management. They enable network operators to approach potential providers of grid flexibility before real time in order to remedy congestion forecast in their networks. In return, network operators have to remunerate/compensate the grid flexibility providers. In addition, physical and economic balancing actions need to be taken to correct the intervention in the market outcome. This requires "smart" distribution system operators that are informed about the state of their networks at all times. This means the development of the grid into a smart grid is a key factor in meeting the future requirements. Not all distribution system operators will be equally affected by this development. How far they will need to become active depends largely on the voltage level and the amount of renewable generation capacity connected to their networks.

The following aspects need to be looked at more closely with a view to achieving the desired aim:

- Which physical and economic balancing actions can be taken?
- How can network operators and grid flexibility providers interact?
- How will flexibility providers be remunerated/compensated?
- What other minimum requirements are there relating to unbundling and transparency?
- How will the incentive regulation scheme provide for regulatory recognition?
- What impact will the approach have on the electricity market 2.0?

4.2.1 Requirements for physical and economic balancing

Correct balancing of the amounts of energy altered is essential with any form of congestion management undertaken by distribution system operators. If a distribution system operator uses storage facilities and loads or curtails renewable or conventional generation to manage congestion, the question is then who is responsible for the economic balancing actions to offset these measures. Unlike redispatch at transmission level, it is frequently not possible to increase and decrease generation from different plants at the same time in order to economically balance the measures.

There are therefore two conceivable options: balancing by the plant operators or balancing by the distribution system operators. In the first case, market players providing flexibility to network operators, or their balance responsible parties, could be made responsible for managing their balancing groups. The costs for an imbalance within a balancing group would then need to be borne by the provider via the use of economic balancing energy. This would apply to storage facilities and loads instructed by a network operator to increase consumption as well as to renewable installations instructed to curtail generation as contractually agreed. Since network operators can only undertake active congestion management in conjunction with market players given a sufficient amount of time, economic balancing should be possible without any significant problems. Balancing could be done through trading in the intraday market and by adapting the amounts generated by plants allocated to the relevant balancing group. Adapting generation and marketing plant capacity can also lead to a decrease in the amount and scope of countertrading required. Larger market players, in particular, will be able to find measures within their portfolio that offset each other and so eliminate the need for economic balancing actions for each individual measure.

In the second case, distribution system operators could be made responsible for the economic balancing actions to offset the measures. Yet this would mean that distribution system operators would need to take on a more active role as "energy traders". However, except for managing the losses and differential balancing groups, from the point of view of unbundling this would not be feasible without discrimination and would not be wanted. In addition, it would mean that distribution system operators would need to build up the technical and personnel resources for 24-hour trading. As an alternative to active economic balancing, distribution system operators could enter into cooperation with the transmission system operators. The transmission system operators could then take the necessary balancing actions either by altering generation by the plants available to them or by procuring energy in the energy markets.

If network operators cannot forecast congestion in sufficient time, they will in any case need to take appropriate emergency measures when the congestion is detected. It will then not be possible for plant operators to balance their balancing groups. Any consequent imbalance would then be corrected by using physical balancing energy. The question then is whether or not in this case the costs of compensation payable to renewable and combined heat and power (CHP) installation operators should be taken into account in the revenue caps. Such an arrangement would have the advantage of creating real financial incentives for a forward-looking approach.

4.2.2 Possible options for interaction between distribution system operators and grid flexibility providers

There are various possible options for interaction between network operators and providers of grid flexibility. It is important to remember that congestion can only be eliminated by actors whose change in behaviour actually alleviates the congestion in the network. This narrows the range of potential grid flexibility providers. Two models are discussed below.

I) Traditional approach (model A)

Network operators already take congestion management measures today – but above all in the form of redispatch by the transmission system operators together with the generators. Another such measure is curtailing renewable generation. The Bundesnetzagentur's feed-in management guidelines regulate the order of priority and compensation for curtailment measures. The range of measures could be extended to include access by distribution system operators to providers of reduced or increased capacity (load reductions or increases) and storage. The actors would need to adapt their behaviour in the event of network congestion as instructed by the distribution system operators. Physical and economic balancing actions would be necessary to offset the shifts in the amounts generated or consumed. The loads or storage facilities under instruction would need to receive financial compensation for any economic loss.

II) Interaction between network operators and grid flexibility providers (model B)

As an alternative to the first option, distribution system operators can in future act as users of grid flexibility. To this end, distribution system operators can interact with conventional or renewable generators and providers of reduced or increased capacity and storage. In this case, the network operators are given a certain amount of control over the generators and providers to eliminate the congestion. Network operators should choose the most cost-efficient option out of the grid flexibility providers with the most effective impact on the congestion. In this model, the network operators negotiate bilaterally with the grid flexibility providers to contractually agree compensation arrangements for the providers' behaviour change. The agreement comprises the ability of a distribution system operator to use grid flexibility at a certain point in time (x) by altering generation or consumption by a certain amount (y) and the payment of compensation to the grid flexibility provider. As in model A, physical and economic balancing actions would be necessary to offset the shifts in the amounts generated or consumed. Since it is the network operators who are then responsible for the detailed technical and contractual arrangements for interaction with the grid flexibility providers, clear requirements for the bilateral contracts need to be defined so as to limit the potential for abuse by the network operators. The terms of the bilateral contracts must therefore be non-discriminatory and must meet the applicable unbundling provisions so as to prevent preferential treatment being given to associated corporate divisions.

Organised platforms can also be an option for interaction given a sufficient number of potential providers. Section 13(6) second sentence EnWG already stipulates a joint internet platform for the acquisition by transmission system operators of reduced and increased capacity from load reductions and increases. Section 14(1) EnWG extends this platform-based option at least de jure to distribution system operators. However, in the case of grid flexibility to manage congestion at distribution level and given the storage facilities and loads in the distribution network, the limited volume and the regional diversity, this option seems to make sense only under very specific conditions. The potential for such platforms is to be seen today as relatively small.

In the Bundesnetzagentur's view, it is therefore appropriate to wait for the outcome of the current pilot projects such as SINTEG that cover such forms of congestion management in the distribution network. Having evaluated the outcome, it would be necessary to clarify the following: which voltage levels would a platform for grid flexibility be suitable for in the first place, and who – from the point of view of unbundling as well – could operate such a platform (network operators or other market actors). It is important to remember that organising platform-based congestion management involves additional transaction costs. It is therefore also important to weigh up the costs and benefits of this form of congestion management compared to other options.

4.2.3 Compensation for grid flexibility providers from network operators

The form of benefit given in return for providing grid flexibility will differ depending on whether a distribution system operator instructs grid flexibility providers to change their behaviour in the interest of the grid by way of administrative intervention (model A) or interacts with providers as a user of grid flexibility (model B). The advantages and disadvantages differ depending on whether the operator pays "prices" either negotiated bilaterally or determined in other procedures or can just pay "compensation" based on the costs or disadvantages arising for the flexibility provider from the operator's intervention. Various possible options are discussed for each model.

I) Compensation in model A

Current practices can provide a starting point for the options for compensation in model A.

Under the new provisions of sections 13ff EnWG (as amended by the Electricity Market Act (Strommarktgesetz)), generators participating in redispatch are still essentially "only" compensated for the disadvantages arising for them from the network operator's intervention. This practice does not allow profitable business models to become established.

The legislative rules for evaluating controllable loads are not as clear cut. The technical effects can be the same as with controlling generation. Yet the arrangements are different. In particular the AbLaV uses a combination of market practices and prices above market level – for reasons that have little to do with appropriate congestion management. This does not provide for a clear-cut evaluation.

Section 15(1) EEG currently provides for operators of installations whose feed-in of electricity from renewable energy sources, mine gas or CHP is reduced due to network congestion to be compensated for 95% of the lost revenues plus the additional expenses and minus the saved expenses. If the revenues lost in a year exceed 1% of the revenues of that year, the operators affected by the curtailment are to be given 100% compensation from that point in time. Even today, renewable and CHP installation operators are to be in financially the same position as they would have been in had there been no intervention.

If the current practice of "pure cost recovery" were to be applied to all grid flexibility options (and in particular loads and storage facilities), ie if a network operator had to ensure that flexibility providers were in financially the same position as they would have been in had there been no intervention in their operating schedules, the actual use of grid flexibility would be dictated purely by the facilities' technical possibilities and the relevant specific statutory regulations.

Advantages and disadvantages of pure cost recovery

One key disadvantage of "pure cost recovery" is that it is difficult to properly determine the costs in each individual case. Generators' additional and saved expenses can likely be determined with sufficient accuracy by applying the redispatch arrangements to loads. It is, however, not feasible to administratively determine final consumers' opportunity costs. Significant methodological problems arise even when determining the compensation for opportunity costs for generation and storage facilities as per section 13a(2) para 3 EnWG. Individualised and reliable calculations are not feasible given the theoretically endless number of generation and usage processes in the various branches of industry. This is also due to the fact that generation and storage facilities have a completely different business basis than loads. Generation facilities earn their money by generating and shifting energy and, under certain conditions, maintaining capacity, whereas loads earn their money – in the industrial sector – with their specific production processes. Hence it is difficult to compare the opportunity costs for flexibility options offered by generators and loads.

Pure cost recovery must also be looked at critically from the point of view of efficiency. Business models for the provision of grid flexibility are unattractive because of the pure cost recovery practice. It must therefore be assumed that alternative measures or flexibility options would not be offered in the case of such compensation. This seems to make perfect sense with respect to conventional power plants, since their construction and design should be tailored not to temporary congestion but to the signals from the electricity market. However, a strict compensation principle would also prevent other innovative and possibly low-cost flexibility services from actively responding to an operator's request for grid flexibility.

One advantage of model A is that neither generation facilities nor loads or storage facilities have an incentive to behave so as to prolong congestion. In addition, an administrative approach can also function under non-competitive and very small-scale conditions with only limited flexibility options. This would be an advantage in particular in rural areas with a high level of renewable generation and only a low load.

Furthermore, pure cost recovery can create a level playing field for flexibility options by applying the same cost recovery method to loads and storage facilities as for redispatch. The aim of this approach would then be the same as with the payment of compensation for renewable installations, and it would be worth considering how far loads should also be included in the order of priority for measures in the feed-in management guidelines. As already indicated, however, the opportunity costs to be compensated vary considerably. While renewable installations are compensated for the amounts of energy not fed into the grid, which can be measured exactly, (industrial) loads are compensated for lost or delayed production.

II) Compensation in model B

Model B differs fundamentally from model A. In this case, it is not a matter of compensating for intervention and administratively determining the costs or opportunity costs entailed in providing grid flexibility; rather, the service provided (allowing control of an installation in the interest of the grid) and the benefit provided in return (remuneration) is negotiated and contractually fixed by the grid flexibility providers and distribution system operators. This gives the operators and providers room for manoeuvre. This interaction must be non-discriminatory and transparent and must meet the unbundling provisions. If it is guaranteed from a network operator's viewpoint that congestion will be alleviated, the operator's choice of grid flexibility provider should be based on economic efficiency. Thus the goal of efficient congestion management can be achieved. In the case of a platform-based option, the remuneration would be determined by the bids submitted by the flexibility providers.

Advantages and disadvantages of negotiated remuneration

Negotiating the remuneration would have the advantage that the providers of grid flexibility assess the costs involved themselves. This means that prices can be freely set within the accompanying regulatory framework. The compensation payable to renewable installations, as a last resort measure, would thus represent the upper limit for remuneration.

This eliminates the need to identify the level of the opportunity costs in an official, administrative process. Assuming there was sufficient competition, an efficient price for grid flexibility would be set. If a network operator considers the remuneration requested economically reasonable at a certain point in time (x), the operator will choose this option. This is then in any case cheaper that curtailing renewable generation and leads to better integration of renewable energy. If the distribution system operator does not consider the flexibility option economically reasonable, the operator can choose to curtail renewable generation as a last resort, for which the usual compensation is payable. This approach can therefore also create a level playing field for flexibility options (see below for regulatory recognition of costs under the incentive regulation scheme).

However, model B also has disadvantages. Giving distribution system operators and grid flexibility providers room for manoeuvre in negotiating the remuneration can result in providers – in particular in small-scale, integrated structures – behaving so as to prolong congestion and designing their business models accordingly. In addition, the liquidity of grid flexibility can locally be very limited. This can lead to individual providers having too much market power. If grid flexibility were procured via a platform – and depending how prices were set in the bidding procedure – uniform pricing could for instance mean that the marginal provider's high market prices would lead to high prices and thus excessive costs for the provision of grid flexibility. All these factors would be counter to the aim of efficient congestion management.

Unlike in model A, negotiated remuneration could actually lead to storage facilities or loads being available to distribution system operators for congestion management. This could give rise to the concern that the energy-only market (EOM) would have less flexibility, since these actors would no longer orient themselves solely to the electricity market.

However, it can be assumed that the grid will only need to use flexibility services at certain times of the year. The fact that storage facilities and loads will have additional earnings potential will enable additional flexibility options to develop that are then available to the market for the majority of the time. In other words, the electricity market could also benefit from them. However, the electricity price signal is supplemented by other price signals that may create temporary local incentives for loads and storage facilities, distort the wholesale market and remove the planning basis for investment decisions.

Basis for compensation/remuneration

Irrespective of these two variants – model A and model B – the question of whether compensation/remuneration should relate to energy-based or capacity-based prices is to be discussed. In turn, the question arises as to whether – as in the procedure under the Interruptible Loads Ordinance – loads should also be remunerated for "reserving" their capacity or only remunerated/compensated for the energy or capacity actually used. In this respect, the Bundesnetzagentur favours energy-based remuneration. This has the advantage that flexibility providers are not able to benefit economically simply by maintaining capacity or base their business models in the long term on the possibility of their grid flexibility services being requested in the event of congestion. This avoids capacity being tied for grid purposes and then no longer responding to the price signals in the energy-only market. Only energy-based remuneration paid for capacity actually used should be recognised under the regulatory regime. This would guarantee the comparability of different flexibility options.

Intermediate conclusions

Congestion is a sign that the grid is temporarily unable to achieve the market outcome. Grid flexibility activated or provided in model A or B provides the necessary corrective action as part of active congestion management (as described). The effect is to be seen as the same as that of the current practice of curtailing renewable energy as part of feed-in management. A well-ordered procedure before real time and economic balancing of the energy amounts are required for each form of grid flexibility provided so as to keep the influence on the market outcome on the right track.

Congestion management in the distribution network will hinge on whether there will be a tendency towards an administrative approach with pure cost recovery where network operators will also be able to instruct loads to change their behaviour in the interest of the grid (model A) or towards an approach where operators will negotiate the services and the benefit given in return with grid flexibility providers (model B) and remuneration will be set in the course of this interaction (or possibly via a platform).

How these two models fit into the traffic lights concept presented in Chapter 2.2. must be discussed.

Possible design:

Needs-based grid expansion means that all market players can realise their plans; at the most network-related measures	Green
Proactive, efficient and well-ordered procedure for congestion management by distribution system operators with the aid of various flexibility options such as regulating conventional, CHP and renewable generation facilities, storage solutions, and load reductions and increases. Two conceivable forms of interaction: model A and model B ➔ economic balancing is required, remuneration/compensation by network operators; ideally before real time	Yellow
Emergency measures (last resort) ➔ no balancing of the balancing group possible at short notice, no remuneration/compensation by network operators; real time	Red

Figure 4: Traffic lights concept for active congestion management in the distribution network
Source: Bundesnetzagentur

The key elements of a future congestion management system should comprise the following accompanying conditions – applicable irrespective of the model chosen – that limit the distribution system operators' potential for discrimination. Key to the goal of congestion management in the most efficient way possible will also be how the costs of compensation are recognised under the incentive regulation scheme. The approach favoured by the Bundesnetzagentur is presented below.

4.2.4 Further minimum requirements for a future congestion management system

Equal incentives under the incentive regulation scheme

In the Bundesnetzagentur's view, the regulatory framework should preferably provide for the equal treatment of all costs for the provision of grid flexibility. As shown in Chapter 2.2, treating the costs of curtailing renewable generation as permanently non-controllable costs constitutes a barrier to efficiency-oriented network operation. As the need for grid flexibility can fluctuate greatly within a regulatory period, there is much to be said for classifying the compensation paid for all grid flexibility services as volatile costs. This applies both to the possible approach in model A and to that in model B.

One option – based on the treatment of costs for energy to cover distribution losses in accordance with Ruling Chamber 8's determination on volatile costs (BK 12/011-108) – would be to adjust the network operators' revenue cap each year by the difference between the compensation for grid flexibility (compensation for feed-in management measures, compensation/remuneration for load reductions and increases and storage facilities) in the base year and the costs in the current year in the ongoing regulatory period. The costs in the base year would also feed into the efficiency benchmarking. The same applies to the treatment of redispatch costs. These costs would consequently also need to be classified as volatile costs in the future.

This approach – following another amendment of the ordinance – would create a level playing field for grid flexibility services under the incentive regulation scheme. It would mean that feed-in management would no longer be better placed under the regulatory framework than the grid flexibility measures already currently used for congestion management in the yellow phase.

In particular in the case of model B, curtailing renewable generation to relieve network congestion is likely to be more expensive than both curtailing conventional generation and other grid flexibility options (as described above) available to alleviate the congestion.

Priority access for renewables would be economically secured in both models. Renewable generation would not be curtailed until all the available alternatives had been exhausted/activated. It would therefore no longer be necessary to formally anchor priority access for renewables in legislation (triggering all the familiar discussions in the context of European law).

Efficiency benchmarking should be used in a system with high capital costs to reward efficient action and incentivise network operators to consider different alternatives when dimensioning their networks and managing congestion. However, it is questionable how far these incentives can still actually have a sufficient effect given the revised ARegV that entered into force in summer 2016.

In the long term, a regulatory approach that rewards efficiency itself in a cost and technology neutral way and abstracts efficiency more clearly from the network operators' actual costs should therefore be considered as an option. This would entail a move away from approaches that differentiate between CAPEX or OPEX-intense solutions.

Unbundling

The unbundling provisions require network operators to be separate from other areas of energy supply. The purpose of the provisions is not only to penalise specific breaches committed by individual network operators. Rather, it is to prevent possibilities of discrimination. In terms of unbundling, what is important is therefore the relationship between network operators and the generators, loads or storage providers whose behaviour the operators use to provide grid flexibility in the event of congestion. In accordance with the spirit and purpose of unbundling, full transparency in the relationships between the network operators and the providers of flexibility and in the technical and economic conditions applicable to the use of the flexibility services is essential in both of the models discussed.

In addition, a distinction must be made between whether operators conclude contractual agreements with these actors and buy services (model B), instruct the actors (model A), or own the flexibility options themselves. Contracts with these actors for measures in the interest of the grid are basically possible. They must be non-discriminatory and must take account of the unbundling provisions of the Energy Industry Act. Associated business units may not be given preferential treatment.

The issue becomes more complex when network operators wish to own or operate such facilities themselves. This is illustrated using storage facilities as an example. Under current legislation, storage facilities are to be viewed as final consumers when taking energy off the electricity grid and as generators when feeding energy into the grid. Problems arise at the latest when a network operator feeds electricity into the grid and thus into the market, since network operators are not permitted to generate energy or participate in trading. As soon as an electricity storage facility feeds electrical energy into the grid, this is to be viewed the same as a conventional generation plant feeding in electricity.

Contractual agreements concluded between network operators and third parties are to serve the interests of the grid conform to the unbundling provisions if they are concluded and worded in a non-discriminatory manner. The question arises whether there may be scope for positive discrimination in favour of affiliated companies within the framework of active congestion management. This concerns for instance the exchange of information about congestion to be managed, the limited number of local providers, and the award of contracts for the provision of flexibility. The same applies when network operators issue instructions to installations belonging to the same vertically integrated undertaking by way of administrative intervention in operating schedules.

Measures must be taken to prevent preferential treatment being given to associated business units in the event of congestion management. Active congestion management therefore requires, at the least, effective network operator unbundling. The equal treatment of all actors is essential here.

All network operators using grid flexibility must implement legal, information and functional unbundling in their companies so as to guarantee a minimum level of equal treatment. Given the current statutory regulations, however, discrimination in this area – owing to complex rules of behaviour necessary for non-discriminatory flexibility management – cannot be completely ruled out; this can only be guaranteed through ownership unbundling.

Transparency

If distribution system operators decide to take congestion management measures, they must communicate this transparently so as to treat all potential actors equally. To limit discrimination, all potential market players must be informed transparently and in good time of the situation in all segments of the network. This must take the form of an active communication requirement and not merely the passive provision of information by network operators. A transparent and non-discriminatory exchange of information should also include a requirement for network operators to publish information relating to contracted and activated capacities and the compensation/remuneration paid in return.

4.3 Restricting load-driven grid expansion

The previous section described in general terms how congestion in the distribution network could be managed. In future, however, challenges on the consumer side could arise in particular at the low voltage level. The question arises whether optimisation measures similar to peak shaving should also be taken in network segments whose dimensioning is determined by the consumer side, so as to avoid costly expansion to accommodate the load down to the very last kilowatt hour of electricity consumed.

Before the energy transition, network size was based more than today on the level of consumption to be covered. This has changed in a number of networks as a result of the energy transition, but consumption is still the determining factor in many networks, and above all in urban networks. Now a new challenge for the networks is emerging. It is expected that a large number of additional consumer loads will need to be connected to the networks in the coming years. These loads include heat pumps and electric vehicles, as well as other applications that are currently unknown. What is special about these loads and applications is that their consumption patterns and times will tend to coincide. This means that a large number of consumers will simultaneously react to a price signal or display certain collective behaviour. Electric vehicles are a good example. Owners are likely to begin charging their vehicles at more or less the same time after work between 5pm and 7pm. In addition, these consumers will generally be able to behave more flexibly; this behaviour could be incentivised by the variable renewables and the response in this context to future increasing price differences. The problem of higher simultaneous loads can be exacerbated even more by suppliers or aggregators centrally controlling both the new consumer loads and those already connected to the grid, such as night storage heating systems, and allowing the loads to respond to the same price signals. This is likely to present challenges in particular in the low voltage networks, since these networks are not designed for this size of loads (rapid chargers deliver > 22 kW) or such simultaneous loads. Consequently, these types of business model can significantly increase the need for grid expansion. One key driver behind this development is the increasing spread of digital technology. In certain fields of application, digital solutions and business models can lead to a more efficient use of infrastructure, but – as this example shows – they can also have a negative impact on the network. To ensure that consumer behaviour in the market – that is only possible because of digital business models – does not lead to load-driven grid expansion beyond a reasonable level, it seems appropriate for network operators to also take into account changing responses on the load side when managing their scarce network resources.

This example also shows that consumers pick up two signals that are not necessarily congruent: a signal from the market that indicates whether the price of a kilowatt hour of electricity is high or low at a certain point in time; and a signal from the network operator triggering certain consumer behaviour, which – depending on how far consumer behaviour in the market places demands on the network infrastructure – acts as a corrective in the interests of the grid.

The challenge is to shape the network operator's signal so as to minimise intervention in market activities. At the same time, the network infrastructure cannot cushion every market outcome. That would be economically inefficient. The regulatory framework should therefore be fine-tuned with due care. Possible starting points are outlined below.

Section 14a EnWG currently provides an arrangement allowing network operators to control interruptible consumer loads that have a separate meter point – ie use them for load reductions, for instance – in return for a reduction in the network tariffs. There is, however, currently no ordinance giving concrete shape to the provision so as to guarantee its sensible and transparent application.

Whatever the current design and the purpose of section 14a EnWG, the question must be asked whether the new flexible consumers expected in the foreseeable future are to be integrated into the grid by expanding the networks or by alternative methods. As with peak shaving on the generation side, it makes sense on the consumption side to limit grid expansion to an economically optimal level. In particular the consumers increasingly active in the market would require a size of network that would only actually be needed for very few hours each year. This would result in costly infrastructure with a low level of usage. It is important to remember that changing the pattern of consumption of these loads scarcely results in a loss of comfort for the users, since the desired energy service – such as heating or driving – can still be provided. Questions and possible solutions relating to how to achieve a moderate expansion of the networks as well as flexible consumer behaviour in the market are discussed below.

Active control by distribution system operators

One possible approach would be to use the legislative power to issue an ordinance so as to give concrete shape to the arrangement provided in section 14a EnWG. The fact that this power has yet to be exercised shows how difficult it is to find the right design for the arrangement. At present, electricity distribution system operators are required to give a reduction in network tariffs to suppliers and final consumers at the low voltage level with whom they have concluded network access agreements in return for being able to control fully interruptible consumer loads that have a separate meter point – in particular night storage heating systems and heat pumps – so as to relieve the network. Control of the loads must be reasonable for these final consumers and suppliers, and the loads may be controlled either by the network operators themselves or by third parties as instructed by the operators. At present, fixed time windows are usually defined for when the loads can be controlled.

The Energy Transition Digitisation Act (Gesetz zur Digitalisierung der Energiewende) makes smart metering systems mandatory for these controllable consumer loads. This could increase the possibility for network operators to directly control the loads, as at present fixed periods are usually defined for when the loads cannot be controlled because of a lack of effective control technology.

A certain degree of standardisation would be a necessary aim of an ordinance giving concrete shape to the arrangement. This is needed to achieve transparency and reduce transaction costs. The questions to be clarified, for instance regarding the level of remuneration, are discussed further below. In principle, developing the opportunity for active control provides distribution system operators with a tool to expand their networks in an economically efficient way. The amount of effort required of the network operators for control and coordination is still relatively large in this model, even with a higher degree of automation.

Defining a simultaneity factor

Another model[7] is currently being discussed as a possible approach to prevent congestion in the distribution networks but at the same time allow as much flexibility as possible for the market. In this model, distribution system operators would define allowed quotas or simultaneity factors for different network segments. For example, a simultaneity factor of 0.8 for a network segment would mean that suppliers would only be allowed to connect 80% of the capacity of the controllable consumer loads under contract in that segment. In this case, the suppliers or aggregators would control the consumer loads as instructed by the distribution system operators. Simultaneity factors could be calculated using either simulations or real measured data. Different factors should be defined for different areas and times so as to take account of (seasonal and intraday) fluctuations in consumption and generation. In a further step, local generation could be taken into account; this could lead to even higher simultaneity factors, in particular for the midday hours. The controllable consumer loads would receive a reduction in the network tariffs.

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[7] "Flexible Heat Transfer Systems" pilot scheme, EnBW, 2015.

The aim of avoiding network congestion and thus the need for expansion can be achieved with this approach without the distribution system operators having to actively intervene in network operations. This simplifies implementation for the distribution system operators, but also involves more forecasting work. The approach also has positive effects for suppliers with a larger number of different controllable consumer loads under contract in a specific network segment, as they can then optimise use of the loads according to availability and the willingness to pay. The restrictions for the controllable consumer loads are kept to the minimum necessary in each case, thus achieving welfare gains.

The ability of suppliers to optimise use however also has a disadvantage. The model creates an incentive for monopolisation in the individual network segments for which simultaneity factors are defined. A controllable consumer load (eg 22 kW) under contract with a supplier with just this one controllable consumer load in the pool for a network segment (simultaneity factor = 0.8) would be permanently restricted during times of congestion. In this example, the load would be permanently restricted to 17.6 kW and might then soon switch to the market leader in the segment. The smaller the area (eg just one low-voltage section), the bigger the problem.

It is questionable however whether the market leaders in the individual network segments would actually be able to charge monopoly prices and earn monopoly profits. The entry barriers for marketing controllable consumer loads in the individual network segments are not likely to be particularly high. Suppliers contracting new controllable consumer loads will incur hardly any irreversible costs. This potential competition will discipline the market leaders. If market leaders exploited their monopoly positions, new suppliers would enter the market and entice customers away from the market leaders ("hit and run competition").

The advantages of the model are the small effort involved for the network operators in directly controlling the loads and the positive effects of optimised intervention.

Unresolved issues regarding section 14a EnWG

One key unresolved issue is how large the reduction in network tariffs should be. Most of the operators' current special network tariffs are equal to between 20% and 40%[8] of the general network tariffs for customers at the low voltage level. However large, the reduction will be the main factor determining the availability of controllable consumer loads, and vice versa. This also raises the question of how often and how much the consumers' loads may be curtailed and whether consumers are obliged to participate if the relevant conditions are met. Another question would be whether the curtailment of one controllable consumer should result in an additional reduction in the network charge to be paid. In principle, the question arises whether and, if so, which limits would need to be defined for when the network should be expanded, so as to prevent excessive and ultimately economically inefficient curtailments (similar to peak shaving with the reduction of 3% per installation). However, restrictions on the consumers' usage must not go too far and daily energy requirements to satisfy the consumers' basic needs (mobility, heat) must be guaranteed.

[8] This includes reduced concession fees and lower VAT payments.

Distribution system operators are currently obliged to give all consumers meeting the relevant conditions this reduction in tariffs even if the operators have no benefit. This obligation is contrary to the aim of enabling economically efficient network operation and expansion. Network operators should therefore be able to choose whether and in which network areas to use this option. Clear criteria are needed to prevent discrimination against individual controllable final consumers. For example, the network segments to be subject to the arrangement should be clearly identified. Another possibility would be to make control mandatory for flexible consumer loads with or above a certain capacity, so as to provide network operators with a reliable tool.

Another question to be decided would be who would have priority in the case of "multiple marketing": distribution system operators, transmission system operators, or marketers in the spot markets. There is much to be said for giving priority to the distribution system operators, since they have only a very limited circle of providers to solve local problems. This could, however, restrict the development of smart products for the (balancing or electricity) markets. Well-functioning, standardised communication between all players is essential in any case.

Whichever approach is chosen, it is important to remember that there are still more than two million electric heating customers in Germany. Electric heating systems are only remotely economically efficient because of the network charge reductions under section 14a EnWG. In both of the models discussed, however, controllable consumer loads would only receive a reduction in tariffs if they were in a constrained area and if the network operator needed to use flexibility services. All other loads would need to pay the full network tariffs. Transitional arrangements would need to be found to accommodate the consumers concerned.

Incentive effect: remuneration through network charge reductions or incentive regulation

The two possible approaches presented above have been discussed in conjunction with remunerating flexibility by giving a reduction in network tariffs. This way of remunerating flexibility is relatively simple for network operators and consumers since no additional payments are necessary. This is an advantage especially when there are a large number of small consumers. This approach is revenue neutral for network operators, since the lower network tariffs paid by some consumers are ultimately balanced out by the higher network tariffs paid by other, inflexible consumers. By exploring smart solutions with controllable consumer loads, distribution system operators can avoid inefficient costs from additional network expansion in the benchmarking. Yet not investing in network expansion also means that distribution system operators do not increase their capital base on which they could earn a return.

The alternative would be to remunerate flexibility by direct payments outside the network charging regime and within the incentive regulation scheme. The costs should then feed into the benchmarking and not be treated as "permanently non-controllable costs" (see the discussion in Chapter 3.5).

The future legal arrangements should allow network operators to decide whether to define quotas or to directly control loads themselves. Both options are feasible. The question as to which option is ultimately more advantageous would need to be looked at in detail. It is important for any unresolved issues to be settled as soon as possible so as to ensure standardisation.

4.4 Linking special network tariffs more closely to grid interests

A network tariff structure that reflects the costs of using the networks leads from a static point of view to efficient infrastructure pricing. Following this premise, network tariffs should adequately reflect shortages in the network. From a static point of view, a network charging structure designed to promote the interests of the grid should be based on these criteria.

This could lead to situations where the price signal from the electricity market and the shortage signal from the network tariffs give different behaviour incentives. These differing prices signals would need to be accepted and not misunderstood as "distortions". In fact, different price signals would be the only way to ensure that the use of available and future flexibilities is statically efficient.

This then means that two separate signals are sent – one for shortages in the network and one for energy supply and demand. Network users would then respond to a combination of the network and the market signal.

The network charging structure essentially includes a suitable signal for shortages in the form of the capacity price – at least wherever shortage is determined by consumption. A network charging structure developed to reflect the costs of the network and the shortages in the network could help to reduce congestion, provided that the network charge inherently incentivises network users to behave in the interest of the grid, ie as it were sends out a signal serving the interests of the grid. Signals sent more locally and closer to real time would be more efficient in static terms. But this would also make things more complex.

Demand-side flexibility could be strengthened in the future by making this signal more flexible and more dynamic with respect to the situation in the individual networks. This, however, requires both users and network operators to have a high level of information about the situation in the networks. Yet the increasing spread of digital technology for both networks and consumer loads certainly opens up possibilities here.

In light of the above, coupling the network tariffs with the price signal from the electricity market is not recommended. It would lead to the fact being ignored that network resources are limited. This would result in excessive grid expansion or regular action by network operators to correct the market outcome in the form of redispatch.

Yet a secure and economical electricity supply is and remains the top priority in any case. The electricity market 2.0 is the key instrument for a secure and low-cost electricity supply. The option of linking up the special network tariffs must therefore always be discussed in light of the current and potential impact on the electricity market 2.0.

It is important to remember that long-term refinancing of the network costs must still be guaranteed even if individual network customers have different network tariffs based on congestion pricing.

Initial starting points for a charging regime designed more to promote the interests of the grid are provided by the arrangements for special network tariffs set out in section 19(2) StromNEV. However, the question here would be whether the identified shortcomings of the current arrangements under section 19(2) StromNEV can be corrected or whether in the long term the arrangements for atypical or electricity-intensive network usage should be replaced by completely new arrangements.

The aim of revised arrangements should be to make a reduction in network tariffs conditional on behaviour serving the interests of the grid. Here, account would need to be taken of the situation in the individual networks. At the same time, the arrangements must be administratively manageable.

Against this background, the Bundesnetzagentur believes that a discussion about reworking the arrangements for special network tariffs should address the following issues:

Section 19(2) first sentence StromNEV

The current arrangements are based solely on the time of the peak load in the network to which the user is connected. The fact must therefore be taken into account that, in certain network areas, dimensioning is now no longer determined by consumption, but by the feed-in from distributed generation sources. In such networks, rewarding a reduction in consumption is superfluous and in some cases can even be counterproductive.

- Many network operators overall consider the current arrangement under section 19(2) first sentence StromNEV to be unnecessary. Firstly, many consumers benefit from deadweight effects because their peak load does not fall within the network's peak load period due to production or operational reasons. Secondly, the incentive for a specific behaviour change is frequently not necessary because many networks are well developed.
- The arrangements should be as flexible as possible so as to enable individual network operators to actually adapt their incentives to the specific network loading. A first step would be to make it possible to adapt the criteria for defining peak load periods to the network's operational requirements at shorter notice, ie it should be possible to make changes on a monthly or even shorter (eg day ahead) basis where necessary.

Section 19(2) second sentence StromNEV

Given the increasing changes in the energy supply system, fundamental modifications will be needed here. A high and consistent consumption of electricity given the conditions of an overall fluctuating energy system – as will be seen in the medium term with well over 40% of electricity accounted for by volatile renewable generation – will no longer be an appropriate criterion for special network tariffs. The current individual network tariffs are of less and less technical benefit for the networks. High permanent loads will no longer be needed even for minimum conventional generation. The value of a consistently high level of electricity consumption would then only consist for the network in a consistently high level of network tariff payments.

The current exceptions to the arrangements and those vigorously called for by the providers of flexible loads (eg under the Interruptible Loads Ordinance, balancing energy and redispatch arrangements, SINTEG projects) show that the present arrangements under section 19(2) second sentence StromNEV should also be amended so that the larger potential flexibility options are no longer specicially restricted to the large industrial consumers but are accessible to the whole system.

The individual network tariff scheme should be revised with the aim not of restricting reductions in network tariffs but of enabling access specifically to the flexibility potential of large consumers. The approaches currently under discussion indicate the direction for future developments: If certain behaviour does not count towards the minimum number of hours of use per year, the restriction will be lifted for this behaviour. The system's future flexibility requirements will be met by consistently following this path to the end so as to eliminate the fundamental (perverse) incentive to design plant inflexibly for permanent operation; for this is the crucial point. The use of consumer flexibility to benefit the market and/or the grid will precisely involve a move away from consistent electricity consumption. The key to success in the medium term can therefore be to remove the "entry threshold" of a certain number of hours of use per year.

One possible option would be to freeze the level of the current privileges for a limited period of time (eg three years) and remove the requirements for a certain number of hours of use per year. The privileges can be frozen by fixing the allowed reductions as a percentage of the published network tariffs.
Reductions in tariffs can also be made conditional on additional criteria such as prequalification for the balancing market, willingness to participate in redispatch, or the requirements set out in the Interruptible Loads Ordinance. This would take account of the fact that congestion in the network is relieved not solely by individual behaviour but in particular by the statistical effects of non-simultaneous consumption; the higher the voltage level, the more widespread the technical balancing effects are and the higher the number of consumers that contribute collectively to the benefit of the grid [at present, 21% of the users paying special tariffs under section 19(2) second sentence StromNEV are connected at the high voltage level, 31% at the high/medium voltage level, and 48% at the medium voltage level]. This would free the companies from the fetters of the permanent load, enable them to use their flexibility potential and would in any case not make them economically worse off than under the present arrangements. Network operators should be allowed to define a permissible annual peak load so as to avoid harmful network loading.
The aim of this proposal is not to cure the incentive effects of permanent load requirements by making exceptions and supplementary rules, but to directly address the cause of the problem.

Adopting such a model for a limited period would provide the time needed to discuss a long-term solution. The solution should provide for pricing based on the "user pays" principle for industrial electricity customers that use the network financed by the general network tariffs as well as for access to the flexibility potential offered by these customers. For instance, in the case of final consumers connected to higher network levels, the fact could generally be taken into account that these voltage levels primarily have a distribution function for the downstream levels and because of this function need to bear a large part of their costs.

4.5 Cellular models

When discussing the use of flexibility we often hear the call for "cellular" models. Cellular models aim to balance local generation and consumption at the lowest possible level. A cell could, for instance, consist of one individual household generating its own energy with a solar PV installation and storing the energy generated with its own battery storage system; this would be the smallest possible cell. Any surplus energy that a cell has generated but cannot use itself and any energy that a cell needs but cannot generate itself is to be passed on to or taken from adjacent cells. Cells with a large number of commercial and industrial customers and cells with a high density of development that do not generate sufficient energy would be balanced out by importing energy from adjacent cells generating a surplus. Balancing generation and consumption locally would mean that renewable energy sources could be adequately integrated into the electricity supply system and the amount of transmission capacity required could be significantly reduced. In addition, creating a direct link between users and the necessary technology would achieve acceptance for the energy transition.

In the Bundesnetzagentur's view, there is no reason why individuals or communities should not aim to balance generation and consumption as locally as possible. This could actually lead to the general public being more willing to take part in the energy transition and also accept potential uncertainties. Local energy balancing is already possible in today's market system. Everyone in the market has the option of concluding contracts with local generators and thus acquiring the electricity they need from local sources[9]. What is essential here is that every kilowatt hour of electricity consumed must still be allocated to a balancing group. Disadvantages for market players balancing energy locally that may arise because the players are no longer able to use all the supply options available in the energy market are economic in nature and must therefore be taken into account by the players when opting for such a model.

Cellular models would be feasible as a supply option for a small proportion of the consumers, but not as an organisational principle for the entire German and European electricity system. Security of supply in large consumption centres cannot be guaranteed with small-scale structures – or only with significant additional economic and ecological costs. Since the capacity to exchange electricity between the cells is limited, additional costly flexibility options would be needed as back-up capacity (eg storage or power-to-x). In terms of economic efficiency, cellular models are not recommended since it is not the generators with the lowest marginal costs that are used – as is the case in the wholesale market – but the generators that are locally available. Overall, cellular models have a tendency towards small, illiquid markets and represent a move back to the era before liberalisation and unbundling.

The very increase in the share of renewable generation makes the exchange of electricity above regional level important and economically rational. A uniform market and a well-developed grid provide the basis enabling advantage to be taken of the regional differences in consumption patterns.

4.6 Provision of flexibility by storage

Electricity storage is essentially a good way of separating the production and consumption of electricity in terms of time and is a potential provider of flexibility in this context. As with any other flexibility option, however, it is worth taking a closer look at the details.

There are various technical solutions for electricity storage. Pumped storage units can be as large as fossil fuel power plants, while domestic battery storage systems are similar in size to small private solar PV installations. All sizes in between are possible – either today or in the future.

Storage can be used to benefit both the electricity market and the electricity grid. As with other flexibility options, there is a degree of tension between the two. Using storage to benefit the grid can make the market less liquid, while using storage to benefit the market frequently leads to greater use of the network or the need for network expansion.

Using storage to benefit the market means that storage operators take advantage of the price differences in the electricity market for arbitrage trading, contributing to a reduction in electricity price volatilities. Pumped

[9] This is, of course, only possible explicitly in contractual or economic terms: physics will in any case ensure that the electricity actually consumed comes from the nearby wind farm and not from the lignite power plant far away in Brandenburg.

storage, for example, has traditionally been used in this way. The present market situation with a high degree of cost-effective flexibility allows only low earnings to be generated with this business model. Even fully depreciated pumped storage plants are currently unable to generate sufficient earnings to cover the full costs. This is true although there are wide exemptions for pumped storage in respect of both network tariffs and the renewable energy surcharge: grid-connected storage plants are fully or largely exempt from network tariffs, and all storage – including storage losses – is fully exempt from the surcharge.

The fact that even fully depreciated storage plants with broad privileges show low profitability, at best, makes it clear why specifically costly storage plants are still less able to enter the market without wide privileges and open or hidden funding. With today's costs, battery storage systems would need to generate a revenue of around 200 €/MWh in the electricity market.[10] The costs for larger systems are likely to be somewhat lower. For the most part, current market price fluctuations amount to only 10% of this value. Battery storage systems are therefore still a long way from participating in the normal electricity market.

This indicates that there is no need in the market at present or in the foreseeable future for storage as a flexibility option. There are a large number of other flexibility options that can provide the required flexibility in the market at significantly lower costs than storage solutions. This may change in one or two decades' time; investing today in this still very expensive technology drives up the costs of energy supply without bringing any advantage.

One example of the use of electricity storage to benefit the market is the balancing market. Profitable battery storage projects can be seen in the market for primary balancing capacity. These projects must meet the same prequalification requirements as the other market participants. Such projects that face the competition and take hold in the market are welcomed by the Bundesnetzagentur. Not only battery storage but also other storage solutions are able to generate reasonable revenues given the current parameters for procuring balancing energy, even though here too there is no shortage of flexibility options and competition is keen.

The expansion in storage effectively seen today is taking place within a system of funding and regulations that is not suited to this mass application. The euphoria about storage threatens to bring a repeat of the costly solar PV boom – which resulted in high costs for the community – but in this case without a corresponding benefit. At present, storage systems are mostly refinanced via segregated markets and market niches. Storage is frequently used to increase economic optimisation for self-consumption. The revised statutory regulations on renewable energy surcharge payments in the case of self-consumption from storage have remedied the problem arising from the fact that the surcharge was seen to have been paid twice for electricity placed in temporary storage; the self-consumption privilege is now higher than the specific storage costs, which means that at present the costs of investment can be easily covered.

The use of storage for self-consumption does not, however, provide anything to the market in return. On the contrary, it increases the problems and costs for the general electricity supply system because it is virtually impossible to predict final consumers with storage and because of the absence of the consumers' demand in the wholesale market, where there is genuine competition. This economic optimisation does not contribute

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[10] Source: iSEA/RWTH Aachen (2016), *Wissenschaftliches Mess- und Evaluierungsprogramm Solarstromspeicher, Jahresbericht 2016 Speichermonitoring*.

towards economic efficiency. The loss in network tariffs and surcharges is borne by other players in the electricity market. This imbalance cannot be corrected by extending the privileges in a mass rollout of solar PV storage and tenants' electricity models – unless the loss is financed by taxes.

The often significant energy losses from electricity storage result in unwanted effects for the decarbonisation of the electricity supply. Ideally, a new battery storage system loses around 10% of the electricity stored. In practice, the amount of energy lost is often considerably higher – and may be around 30%. Pumped hydro storage losses can be up to more than 40%, while compressed air energy storage losses can be more than 50%, depending on the technology used. The additional electricity required to compensate for these losses needs to be generated in the system. At present, this additional electricity is nearly always generated by hard coal plants. If a large pumped storage plant with a capacity of 1 GW and an efficiency of 80% generates at full capacity for 1,000 hours a year, there will be a loss of around 200 GWh/a; this is replaced by coal-generated electricity, resulting in 200,000 tonnes of carbon dioxide.

The actual use of large and, above all, small-scale storage solutions benefits the operation of fossil fuel power plants rather than the success of the energy transition in two further ways:

1) In summer, the solar electricity generated at midday is stored; this lowers the flexibility requirements for coal-fired power plants. Coal-generated electricity can be produced specifically more cheaply, and plans to increase the technical flexibility of lignite power plants can be put back even further.

2) Households with a standard load profile that store electricity themselves, thus optimising their self-consumption, will deviate significantly from the load profile. The differences will then need to be balanced out by physical balancing energy; at present mainly fossil fuel power plants are kept available to provide this balancing energy as what are known as the "must run" generators.

Storage systems in private households or electric vehicles that also participate in the electricity or balancing market can trigger the need for additional transport capacity at the low voltage level. They potentially have a specifically strong effect of driving up network infrastructure prices and can magnify the technical network problems in light of the existing problems with public acceptance of grid expansion.

The use of storage to benefit the grid raises technical and regulatory issues that place narrow limits on such use. Storage is not suitable as a permanent alternative to grid expansion.

The scale of the congestion on Germany's transmission grid is so large that it would be impossible for storage facilities to provide any noticeable relief. An HVDC corridor with a capacity of 2 GW would transport 10 GWh of electricity given winds lasting 5 hours. One of the largest storage projects currently running is WEMAG's battery park in Schwerin, which has a capacity of 14.5 MWh. Nearly 700 of these facilities would be needed to store 10 GWh of electricity, provided they were completely empty when the winds began. Neither this assumption nor the probability of 700 such projects is realistic.

As shown in Chapter 4.2, however, it would be conceivable for distribution system operators to contract storage solutions to actively manage congestion in the interest of the grid. In this case, storage would be competing with the other flexibility options available to the operators. Using storage will be an attractive solution for distribution system operators whenever it offers an economical alternative to other flexibility options. It is essential that the accompanying conditions presented above – and in particular the unbundling provisions – be met.

The flexibility potential of electricity storage solutions can be used to benefit both the grid and the market. The debate about electricity storage overestimates the necessity and capabilities of such solutions, while underestimating the costs and side effects. The challenge here is to create a level playing field for all flexibility options, which in this case means withdrawing current privileges enjoyed by storage. No players should receive any special support whatsoever, since this distorts the market outcome and makes the system less efficient.

5 Conclusions

Generation and consumption need to be made more flexible in the medium and long term so as to efficiently integrate the increasing share of renewables into the electricity markets and the electricity system and to guarantee security of supply. Here, the electricity price is a key allocation signal. Yet various regulatory elements of the present legislative framework are characterised by perverse incentives and distort this signal. This prevents a level playing field in the use of flexibility. To improve access to the flexibility options in the market, distortions to the market outcome arising from special support schemes should be eliminated, as they make the system less efficient and more expensive.

The steady growth in renewables, the response of the market actors to intermittent generation, and freedom in planning in connection with peak shaving all mean that situations may increasingly occur where, either temporarily or permanently, existing network infrastructures are not sufficient to provide the required transport capacity. This results in network congestion or the risk of congestion. At present, hardly any measures are taken in the distribution network to actively manage congestion. The first choice for network operators is therefore to curtail renewable generation. There are hardly any genuine market-related options available to the network operators. The lack of use of such options is also due to perverse incentives in connection with the recognition of costs under the incentive regulation scheme.

In an electricity system in which more than half of the energy generated comes from renewables, active congestion management is becoming more important. A model is therefore outlined presenting potential congestion management options for distribution system operators in a future electricity system. In the context of congestion management, there are various options available to the network operators to deal with congestion. Here, it is essential that the regulatory framework provides for the equal treatment of all grid flexibility options. This is necessary to enable the network operators to choose the efficient measure from various options. One conceivable form of interaction between distribution system operators and market players would be the creation of a market for grid flexibility. This would, however, also require a considerably higher level of transparency and effective unbundling as essential conditions. In addition, a strategy would be needed to deal with the risk of market power and market players' strategic behaviour. Before practical implementation, it would also be necessary to look at the impact on the liquidity of other market segments and the potential impact on the fundamental design of the electricity market and the configuration of bidding zones.

Furthermore, possible answers should be discussed to the question of whether, to what extent and, if applicable, with which instruments load-driven grid expansion should be controlled and restricted. One possible approach would be to use the legislative power to issue an ordinance so as to give concrete shape to the arrangements provided in section 14a EnWG. The design of these arrangements will be of particular importance within the framework of sector coupling.

In principle, price signals – whether to balance electricity demand and supply or to reflect shortages in the network infrastructure – should always be as undistorted as possible. Here, it must be accepted that the signal for the electricity market and the signal for network usage are not identical and may even contradict each other because of the different shortages.

Yet a secure and economical electricity supply is and will remain the top priority. The electricity market 2.0 is the key instrument for a secure and low-cost electricity supply. The question as to how far the existing structures should be reconsidered must therefore always be discussed in light of the impact they have on the electricity market 2.0.

The arrangements for network tariffs for atypical network users in section 19(2) first sentence StromNEV could be designed as a future starting point for pricing shortages in the network. By contrast, the present arrangements for individual network tariffs for electricity-intensive network users in section 19(2) second sentence StromNEV will no longer match the future demands on a highly flexible energy system, and fundamental changes will therefore make sense. One possible option in particular as a medium-term solution would be to freeze the level of the current privileges for a limited period of time (eg three years) and remove the requirements for a certain number of hours of use per year. Freezing the privileges, which could be coupled with certain conditions, would enable the freed enterprises to respond flexibly to the electricity prices and would open up access to the flexibility potential of relevant loads.

List of figures

List of abbreviations

AbLaV	Interruptible Loads Ordinance
AC	alternating current
ARegV	Incentive Regulation Ordinance
BBPlG	Federal Requirements Plan Act
CACM	capacity allocation and congestion management
CAPEX	capital expenditure
CHP	combined heat and power
EEG	Renewable Energy Sources Act
EEX	European Energy Exchange AG
EnBW	EnBW Energie Baden-Württemberg AG
EnLAG	Power Grid Expansion Act
ENTSO-E	European Network of Transmission System Operators for Electricity
EnWG	Energy Industry Act
EOM	energy-only market
EU	European Union
GW	gigawatt
GWh/a	gigawatt hours per annum
HVDC	high voltage direct current
kV	kilovolt
kW	kilowatt
kWh	kilowatt hour
KWKG	Combined Heat and Power Act

iSEA/RWTH Aachen University	Institute for Power Electronics and Electrical Drives/RWTH Aachen
MsbG	Metering Operations Act
MW	megawatt
MWh	megawatt hour
NABEG	Grid Expansion Acceleration Act
OPEX	operating expenditure
PV	photovoltaic
SINTEG	Smart Energy Showcases – Digital Agenda for the Energy Transition
StromNEV	Electricity Network Charges Ordinance
StromNZV	Electricity Network Access Ordinance
TSO	transmission system operator
TWh	terawatt hour
VAT	value added tax

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