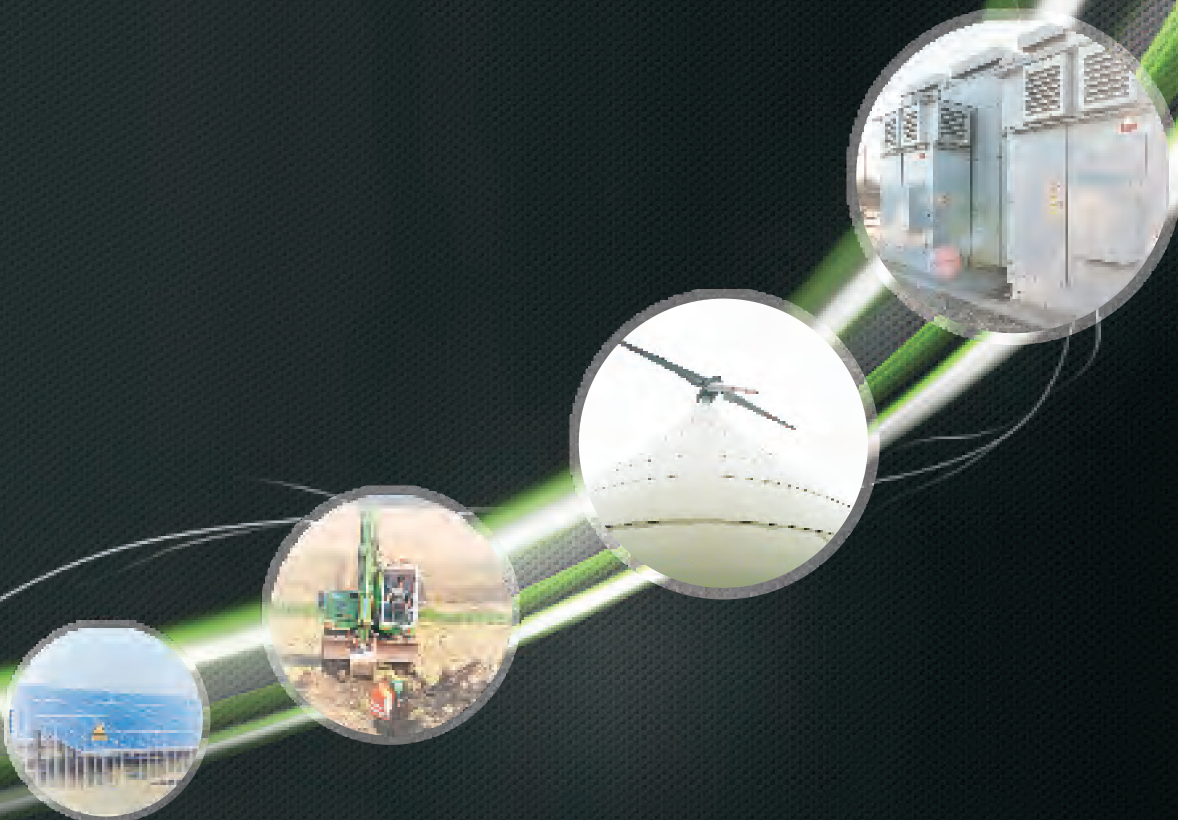
Integrating Renewables in Distribution Grids

Storage, regulation and the interaction of different stakeholders in future grids



Stefan Nykamp

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Cover design by Britta Bergjan and Stefan Nykamp.
The figures given in the bubbles of the energy stream show on the front-side a ground mounting photovoltaic power plant, the cable laying in an open-trench with a medium voltage system, a wind generator with a nominal power value of 2.3 MW (own pictures) and a sodium sulfur battery, installed in New York (usage with the kind approval of MTA, New York, © NY Metropolitan Transportation Authority/Patrick Cashin). On the back side, one can see a biomass fermenter with photovoltaic modules on the roof of a stable and the removal of a tower substation (own pictures).

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INTEGRATING RENEWABLES IN DISTRIBUTION GRIDS

STORAGE, REGULATION AND THE INTERACTION OF DIFFERENT STAKEHOLDERS IN FUTURE GRIDS

DISSERTATION

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by

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Abstract

In recent years, the transition of the power supply chain towards a sustainable system based on “green” electricity generation out of renewable energy sources (RES-E) has become a main challenge for grid operators and further stakeholders in the power system. This transition is politically and socially supported to reduce the carbon footprint and/or enable the phasing out of nuclear power.

Hereby, the operation of consumption and generation appliances in grids and market systems has become more complex since multiple stakeholders are involved. Furthermore, the different functions of the supply chain (e.g. production, transmission, distribution and selling of energy) follow different optimization objectives. Hence, the current market design is not appropriately reflected by an integrated view on the supply chain. A disaggregated perspective is required considering that different steering approaches for appliances by different stakeholders could be realized in the future (e.g. based on (global) prices or (local) signals). Moreover, more fluctuating power generation profiles need to be considered since the feed-in of photovoltaic (PV) and wind generators depends on given weather conditions.

The operation of RES-E generators and the steering of flexible consumption appliances may lead to higher peaks in distribution grids. In most instances, the current solution for coping with these challenges is investing in additional, conventional grid assets (such as transformers, cables, lines). However, this ‘copperplate’ scenario will not be sufficient anymore in future power systems with a further increase of the share of RES-E on the total generation since next to regional aspects (transport of power over distances) also temporal aspects (transport of power over time) will be important. Therefore, consumption, generation and storage of electricity need to be coordinated. Next to this match on a global scale (e.g. for complete countries or the European continent) to ensure system stability, also the local aspects need to be considered to avoid unreasonable high costs in distribution grids. Hence, also these grids need to be operated more dynamically using the flexibilities provided by new generation, consumption and storage appliances. Especially the decentralized storage assets placed in distribution grids may provide an important and substantial contribution to deal with RES-E fluctuations. A higher market penetration of these assets in distribution grids is expected in the future, illustrating the urgency for developing concepts for an efficient integration of storage assets in the grids.

To enable the evaluation of new concepts for the integration of RES-E, first the feed-in characteristics of photovoltaic, wind and biomass generators located in a distribution grid area are studied in this thesis. The analysis considers numerous measured feed-in data and shows how the RES-E feed-in profiles correlate. Further important generation characteristics are presented such as indicators for the frequency and for the level of peaks and the dependence of these peaks on the numbers of generators.

The achieved insights from the feed-in profiles can be used for the planning and dimensioning of distribution grid assets. Furthermore, the results are useful for the evaluation of congestion management to throttle RES-E in certain time periods of the year

or for the dimensioning of storage assets in distribution grids. The latter aspect is analyzed in detail such that suitable storage characteristics for an introduction in the electricity system are determined. For this, the perspective of the distribution system operator (DSO) is chosen with the objective of reducing feed-in peaks of photovoltaic and wind generators to avoid or delay the investments in conventional reinforcements. Furthermore, the influence of a larger number of generators on the storage requirements is investigated which is shown to be important for the size of the storage asset. An economic approach is presented to derive break-even points for storage assets as a substitute to conventional reinforcements. For this, operational as well as capital expenditures are considered. For a case study from a real world low voltage grid with reinforcement needs, these break-even points are determined and the main influencing parameters are evaluated. Based on these technical and economic elaborations, the DSOs are able to narrow down the choice of storage technologies for situations with the need for grid reinforcements.

A further important question in this context concerns the role DSOs may play with the operation of decentralized storage assets since several stakeholders may be interested in using the flexibility provided by these assets. This unclear responsibility also applies to the steering of adjustable consumption devices (Demand Side Management), such as electric heat pumps, electric cars or new white good appliances. For decentralized storage assets as well as heat pump appliances, optimal operation modes based on the optimization objectives for a DSO and a trader are derived. Hereby, the objectives for using the assets and exploiting the gained flexibility of the operation differ. The trader is an arbitrageur trying to exploit central price spreads whereas the DSO aims to solve local grid problems. The end users may benefit in both scenarios in terms of lower prices for the electricity consumption. However, it is shown based on real world data that choosing a ‘copperplate’ scenario is not only technically insufficient for a global balance of the consumption and generation. It may even be harmful for the society from an economic point of view when not taking local grid restrictions into account. This perspective is relevant since the investments for the reinforcements can significantly exceed the benefits on the trading side if no restrictions are given for the energy profiles resulting from the trading activities. Hence, a cooperation of the stakeholders in future markets and grids with an increased flexibility in the consumption and storage of energy is recommended from a welfare point of view.

A further important aspect for the energy transition with respect to the perspective of the DSOs is the regulation of grids. In this thesis, it is investigated whether or not innovative investments such as installing storage assets, introducing new voltage regulation appliances or implementing Demand Side Management from a grid operators’ perspective are incentivized by the grid regulation method. For this, main aspects of the German revenue cap regulation are considered. It is shown that investments in grids are hampered in general and that conventional grid reinforcements are preferred rather than innovative solutions. Therefore, the regulation of grids needs to be adjusted to incentivize innovations and enable a successful and efficient energy transition.

Samenvatting

De veranderingen van de laatste jaren in het elektriciteitssysteem leiden tot grote uitdagingen voor de netwerkbeheerders van het distributienetwerk en andere belanghebbenden in de keten. Deze veranderingen komen vooral voort uit het integreren van elektriciteitsproductie uit hernieuwbare bronnen (RES-E); deze energie transitie is maatschappelijk en politiek gewenst om de uitstoot van CO_2 en/of het gebruik van kernenergie te verminderen of zelfs te stoppen.

De overgang leidt tot een grotere operationele complexiteit en verschillende nieuwe mogelijkheden voor het gebruik van consumptie- en productieapparaten in het netwerk en in de markt. De complexiteit wordt nog verder verhoogd doordat verschillende belanghebbenden actief zijn met verschillende optimalisatiedoelstellingen. Daarom is een geïntegreerde visie op de leveringsketen van elektriciteit ontoereikend om de werking van de markt te begrijpen. In plaats daarvan vereist een realistisch beeld een onderzoek uitgesplitst naar de verschillende belanghebbenden, zodat verschillende stuurmechanismen voor apparaten kunnen worden onderzocht, bijvoorbeeld het effect van globale prijzen of lokale signalen. Verder wordt de complexiteit verhoogd doordat elektriciteit gegenereerd uit duurzame bronnen fluctueert, omdat zon- en windenergie afhankelijk zijn van de weersomstandigheden.

Het gebruik van RES-E generatoren leidt tot hogere pieken in de elektriciteitsprofielen in distributienetwerken. In de meeste gevallen worden de uitdagingen opgelost met meer en sterker gedimensioneerde, conventionele netwerkbedrijfsmiddelen (bijvoorbeeld transformatoren, kabels, bovenleidingen). Dit 'koperplaat'-scenario zal niet toereikend zijn als het aandeel van RES-E in de energieopwekking verder verhoogd wordt, omdat niet alleen het transport van elektriciteit over grotere afstanden maar ook over tijd belangrijk is. Dus moeten opwekking, consumptie en opslag van elektriciteit gecoördineerd worden. Dit is van essentieel belang voor de zekerheid van levering voor een globaal gebied (bijvoorbeeld het hele land of het Europese continent), maar ook voor levering op lokaal niveau. Als dit lokale perspectief niet wordt meegenomen in de beschouwing, dan bestaat er het risico op onevenredig hoge kosten voor de uitbreiding van het distributienetwerk. Als gevolg hiervan zal het distributienetwerk op een dynamische manier moeten opereren, waarbij de flexibiliteit van nieuwe opwekking-, consumptie- en opslagapparaten benut wordt. Hierbij zal decentrale opslag in distributienetwerken een belangrijke en substantiële bijdrage leveren aan het passend omgaan met de fluctuaties in de RES-E opwekkingsprofielen. Een groei in de markt voor deze opslag in de nabije toekomst is te verwachten, wat de urgentie voor de ontwikkeling van concepten voor de integratie van opslag in netwerken verder verhoogt.

Voor de evaluatie van concepten voor de integratie van RES-E moeten de opwekkingsprofielen van fotovoltaïsche cellen (PV), wind- en biomassa-generatoren in detail onderzocht worden. Deze analyses van RES-E in het distributienetwerk, waarbij talrijke meetwaarden worden beschouwd, zijn hoeksteen van dit proefschrift. Er wordt blootgelegd hoe de RES-E profielen samenhangen, hoe hoog de pieken zijn en hoe vaak deze pieken optreden. Deze resultaten zijn belangrijk voor de planning van netwerken,

ondersteunend voor evaluatie van opties zoals de beperking van de opwekking van RES-E (bijvoorbeeld in zeldzame perioden met extreem hoge pieken) en voor het ontwerpen van passende opslag in distributienetwerken. Dit laatste aspect is gedetailleerd onderzocht, waarbij passende waarden voor de parameters rond opslag zijn bepaald. Hierbij is het perspectief van de netwerkbeheerder van het distributienetwerk gekozen, waarbij de opslag wordt gebruikt om de pieken en de versterking van netwerkbedrijfsmiddelen te verminderen en het aandeel van RES-E te verhogen. In de simulaties wordt rekening gehouden met PV- en wind generatoren. De uitwerking van deze RES-E technologieën op de opslag karakteristieken is onderzocht. Ook wordt de invloed van meerdere generatoren (in plaats van een) op de waarden van de opslag karakteristieken geanalyseerd. Dit is belangrijk omdat daardoor de grootte van de opslag beïnvloed wordt en de opslag kleiner gedimensioneerd kan worden. Een economische benadering wordt gepresenteerd om break-even points voor opslag als een vervanging voor de investeringen in meer en sterker gedimensioneerde, conventionele netwerkbedrijfsmiddelen te berekenen. Hierbij wordt rekening gehouden met onderhouds- en kapitaalkosten. Als voorbeeld wordt een reële situatie in een laagspannings-distributienetwerk uitgewerkt. In dat geval worden de break-even points en de invloedrijkste karakteristieken geëvalueerd. Gebaseerd op dergelijke technische en economische studies kunnen netwerkbeheerders van de distributienetwerken passende opslagtechnologieën en bedrijfsmiddelen selecteren.

In de meesten landen is de rol van de netwerkbeheerders wat betreft de installatie en het gebruik van opslagapparaten nog niet gedefinieerd. Deze onduidelijke situatie geldt ook voor de aansturing van flexibele consumptie (Demand Side Management (DSM)), zoals elektrische auto’s, warmtepompen en nieuw, slim witgoed (bijvoorbeeld bestuurbare koelkasten). Voor beide technologieën, opslag in distributienetwerken en DSM in de vorm van warmtepompen, worden optimale besturingsmethodieken afgeleid, gebaseerd op de doelstellingen van een netwerkbeheerder en een handelaar. De handelaar probeert winst te maken op spreiding van globale prijzen van de energiebeurs, terwijl de netwerkbeheerders trachten lokale problemen in het net op te lossen. In beide gevallen kan de eindgebruiker van lagere prijzen voor de consumptie van elektriciteit profiteren. Maar zoals in dit proefschrift wordt aangetoond, gebruikmakend van reële consumptie-, opwekking- en netwerkdata, is een ‘koperplaat’ scenario niet alleen technisch ontoereikend voor een globale balans van de consumptie en opwekking. Met het oog op economische vraagstellingen en lokale focus kan het zelfs schadelijk zijn voor de nationale welvaart, omdat investeringen in netversterkingen duidelijk hoger kunnen zijn dan de baten voor de handelaar indien ieder energieprofiel gerealiseerd mag worden. Daarom is samenwerking van de belanghebbenden in de energieketen belangrijk in toekomstige markten en netwerken.

Een ander belangrijk aspect van de energie overgang vanuit de positie van de netwerkbeheerders is de regulering van het net. In dit proefschrift wordt onderzocht of het investeren in innovaties, zoals installeren van opslag en implementeren van DSM, voor netwerkbeheerders economisch nut heeft. Hierbij wordt rekening gehouden met de hoofdaspecten van de Duitse opbrengstbovengrens-regulatie. Hier wordt aangetoond dat investeringen in het algemeen door de reguleringen worden gehinderd. Bovendien, wanneer er toch geïnvesteerd wordt, is het aantrekkelijk te investeren in conventionele netwerkversterkingen in plaats van in innovatieve technieken. Daarom dient ook de regulering van netten aangepast te worden om investeringen in innovaties te stimuleren en een succesvolle en efficiënte energie transitie mogelijk te maken.

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Writing the acknowledgement for a PhD thesis is one of the final steps in the context of a great number of them. The direction, course and length of the doctoral road are not clear at all when starting out. A lot of people have accompanied me during this journey and I'd like use this opportunity to thank some of them.

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van mijn deficiënties in het taalgebruik ☺ - ik heb hopelijke nu iets meer tijd om deze weg te werken.

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Content

1 Introduction

Electricity has evolved to a basic need for mankind in industrial countries and, increasingly, also in the rest of the world. In the 20^{th} century it was mainly produced in central, large power plants using fossil fuels and nuclear power and transported by transmission and distribution grids to the end users. However, the electricity system is about to change. Electricity generation out of renewable energy sources (RES-E) such as photovoltaic (PV), wind and biomass generation has experienced significant growth rates. Further expansion of RES-E installations is expected and politically and socially endorsed. Since these generators are connected primarily to the distribution grids, these grids have to be adapted to future requirements, e.g. considering the number and size of current and future RES-E generators as well as new consumption devices such as electric cars and heat pumps. A second important aspect is that photovoltaic and wind generation depend on the weather situation and hence, the system has to deal with fluctuations in the feed-in. This challenge applies not only for distribution grids but also - technically and economically - for transmission grids, consumption devices, existing generation plants and markets.[1] In the past the generation (supply) of electricity always followed the consumption (demand), so that the flexibility in the electricity system was mainly provided by the supply side. This flexibility is crucial for electricity markets and grids since the supply and demand of electricity needs to be in balance to avoid extensive black outs. Ensuring this balance is even more complicated by the lack of appropriate storage systems, because up to now, storing electricity has only been economically feasible in large pumped hydro power plants. Hence, to integrate the fluctuating power feed-in of photovoltaic and wind generation in grids and markets, a paradigm shift towards generation oriented consumption is required. Furthermore, the increased introduction of storage systems in distribution grids is required to a) support the global matching of demand and supply and b) contribute locally to an improved integration of RES-E in the distribution grids.

The challenges described above are often discussed in the context of the ‘electricity transition’ to a sustainable and ‘green’ electricity supply based on RES-E. The mentioned transition is also required to enable the phasing out of nuclear power, planned in several countries after the nuclear disaster of Fukushima Daiichi in March 2011. Furthermore, the use of fossil fuels, such as coal, natural gas and oil, to generate electricity is seen as an acceleration for the climate change, resulting in an increase of the global temperature, rise of the sea-level and increased frequencies of extreme weather conditions. Stern (2006) calculates the costs for the projected impact of the climate change in the range of 5% and 20% of world’s gross domestic product per year if no actions are taken (similar studies are provided by Goulder and Pizer (2006) and Tol (2009)).

To reduce the negative impacts of the power generation out of fossil fuels and nuclear power, the investments in RES-E capacities has been incentivized in a lot of countries all

[1] As it will be explained later in detail, distribution grids in electricity systems include low, medium and high voltage levels and hence, the electricity grids, industrial and residential loads as well as the vast majority of RES-E generators are connected to.

around the world (for an overview of the current status, developments and initiatives, see REN21 (2012)). Political decisions for installing corresponding supporting schemes are accompanied by societal climatic objectives in several states and continents. For instance in Europe, the 20-20-20 targets have come into force. These objectives imply a reduction of the emission of greenhouse gases by 20% compared to the value in 1990, an increased share of energy produced from renewable sources to the energy consumption of 20% and 20% improvement of the energy efficiency - all to be realized by 2020. The introduction of these targets in national laws was realized in all European community countries. Similar objectives have also been agreed on in other countries all over the world. Some national targets even exceed European climate objectives. For example in Germany, the share of RES-E on the total generation is anticipated to increase to 35% in 2020 establishing also a path to a share of 80% in 2050. Hereby it has to be noticed, that energy is a generic term for the three segments of a) electricity, b) heating and cooling and c) transportation. However, electricity is seen as the most dynamic segment and characterized by some special features, which are explained in the next section. In the further progress of this chapter, the central role of the distribution system operators (DSOs) in the electricity transition is explained (Section 1.2). Main trends and challenges in generation, consumption and storage of electricity going along with the integration of RES-E are briefly presented in Section 1.3. Finally, in Section 1.4 the contribution of this thesis to the research community is discussed and in Section 1.5 the outline of the thesis and the next chapters is given.

1.1 The electricity system

Electricity systems have some characteristics, which differentiate the economic and technical framework for electricity grids and markets from logistics and transactions of other products and services. Important aspects in this context are:

- electricity is always grid connected; the availability of electricity for consumption is only possible with a specific transportation and distribution system. Even in islanded grids, a connection of generation and consumption via lines and a balance of these power flows are required.
- transportation and distribution grids are faced with the conditions of natural monopolies (described later in detail in Section 2.1). The grid monopolist is able to limit and hamper the access to the grid for suppliers. Therefore, a transparent and non-discriminatory grid operation is required which is enforced by a regulation agency.
- electricity is hard to be stored at large-scale; hence, generation and consumption need to be aligned (described later in detail in Section 2.2); an unbalanced situation can lead to a deviation in the frequency in the grid and spacious black outs.
- the availability of electricity is required for a lot of fundamental applications (e.g. usage of IT-infrastructure). In contrast to other energy forms, very limited or no opportunities for substituting electricity by using other energy forms are given (cf. Ströbele et al. (2010)).

Especially the two latter aspects explain why prevailing political discussions and actions are more focused on electricity supply chains compared to other sectors, such as for natural gas. Furthermore, the consumption of electricity is expected to grow in the future. According to an investigation of the European Commission, electricity will almost double its share in the overall energy demand to 36-39% in 2050 (EC (2011)). Furthermore, for the countries in the OECD an annual increase of the electricity consumption by 1.2% is expected till 2035, while non-OECD countries will face even a rise of 3.3% (EIA (2011)). The importance of a reliable electricity system gets particularly clear in case of failures.

- The Northeast black-out in America and Toronto disconnected 50 million people from the grid with costs for the economy of more than 6 billion US$ (Minkel (2008)).
- The Italy black-out in 2003 caused costs only for restaurants and bars in spoiled products and lost sales of 139 million US$ (Bruch et al. (2011)).
- The India black-out in July 2012 affected over 620 million people.

However, it is not only the availability, but also the power quality (e.g. constant voltage values, harmonics) in distribution grids which is important for a reliable supply of connected devices.

For this important infrastructural system, a change to a more sustainable alternative is being discussed now. However, this transition to a smarter system connecting RES-E, management of (local) consumption and considering the real-time requirements in the grids as well as introducing and integrating storage assets, both technically and economically, has to be realized in the existing systems. This process can be seen as an open-heart surgery and requires coordinated actions and jointly accepted objectives, which can be regarded as a huge challenge due to the dimensions of the power systems - for example in Europe, electricity is provided for 430 million people using 230,000 km of transmission lines and 5,000,000 km of distributions lines at medium and low voltage levels. Considering also the substation and support systems, the investments in European electricity grids until now is assumed to amount to more than 600 billion € (ETP SG (2010)). However, a significant fraction of these grids assets was installed already more than 40 years ago. ETP SG (2007) states, that another 300 billion € will have to be invested in European distribution networks over the next three decades. According to the study, approximately the same magnitude of investments is required for renewing and extending generation capacities. Hence, for the transition to a more sustainable and green electricity supply chain, it seems to be of crucial importance to increase the efforts for research for an efficient integration of RES-E and to orientate already now investment programs on the future needs of grids. This is all the more important since currently installed assets will have to operate for the next decades. If the new challenges are not considered appropriately, the danger of sunk costs, decreased efficiency and failures in reaching the climatic objectives and energy targets in Europe is lurking - not only for grid operators but for the society as a whole.

1.2 The role of the distribution grid

The supply chain of electricity is characterized by the parts dealing with the physical energy flow (generation, transmission, distribution, consumption) and other parts focusing on the commodity of electricity (trading, e.g. on wholesale markets and retailing, e.g. to supply the households). Physically, RES-E generators in form of photovoltaic (PV), wind or biomass generators are primarily connected to distribution grids. For example in Germany, this applies for 97.6% of the photovoltaic (PV), wind and biomass generators (BNetzA (2010)). Except for very large industrial companies, the consuming devices are also connected to these distribution grids. Hence, distribution system operators (DSOs) will play an important role in the electricity transition process. A scheme of the grid levels with a differentiation of transmission and distribution grids is depicted in Figure 1-1.

In most countries, DSOs do not have the possibility to influence the size, type or location of new RES-E generators and have to reinforce and/or extend grid assets, if necessary. The distribution grids have often not been designed for the large amounts of distributed generation. The resulting challenges are particularly visible in countries with lots of RES-E. According to REN21 (2012), Germany is the largest markets for PV installations and number three for wind installations in the world. Hence, a lot of challenges facing the technical and economic integration of RES-E are already now visible in this country. In recent years, the integration of such fluctuating power generation has been enabled by (large) reinforcements in grid assets (where needed) to avoid that voltage or load values exceed predefined thresholds. A study of e-Bridge (2011) evaluated a reinforcement need for additional cables of a length of up to 380,000 km (an increase in length of 24%) in German's distribution grids with costs of up to 27 billion € until 2020. Dena (2012) estimated costs of up to 43 billion € until 2030, whereby both studies considered the expected growth of RES-E. The need for these investments occurs mainly in regions where the local RES-E production significantly exceeds the local consumption. Already today with a much smaller penetration of PV, wind and biomass generators, this is temporarily (e.g. with strong sun radiation and wind speed) the case in certain rural areas.

The current regulation design forces grid operators to adjust investments and operation strategies based on efficiency criteria. Hereby, the incentive regulation is a very common used approach to regulate grid operators. Examples for this kind of regulation are the revenue cap regulation (e.g. in Germany) or yardstick competition, e.g. implemented in the Netherlands (cf. for an overview in Europe, Haney and Pollitt (2009), CEER (2011) and Lapillonne and Brizard (2013)). As it will be shown in this thesis, these regulation mechanisms have a strong influence on the investment decisions of DSOs for the integration of RES-E.

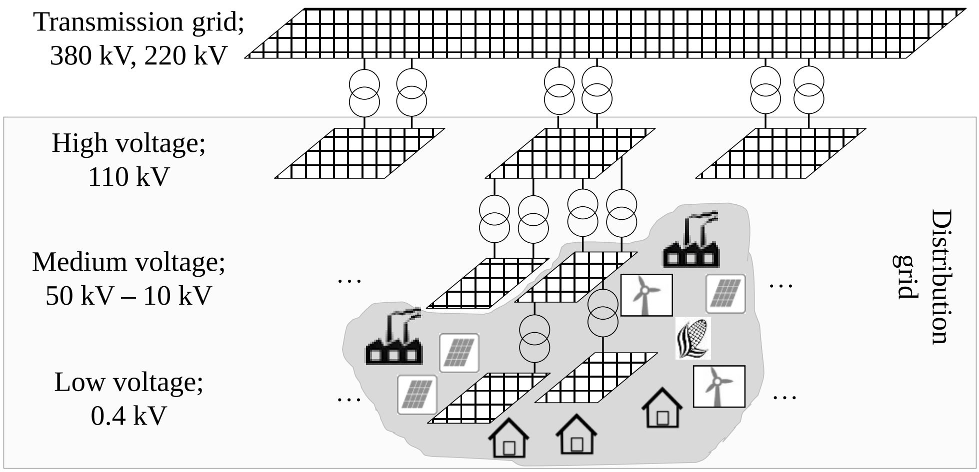


Figure 1-1: Scheme of electricity transport and distribution

1.3 Trends for the integration of RES-E

The need for conventional reinforcements for the integration of RES-E may be reduced by the installation of emerging decentralized storage assets, such as batteries, biogas buffers or power to gas applications which may be used to level out the feed-in peaks of PV and wind. An open point in this context is the role, influence and responsibility of (distribution) grid operators for the operation and ownership of storage assets. Furthermore, voltage regulation appliances, such as on-load-tap changers in substations are an interesting alternative to cope with voltage increases caused by decentralized RES-E. An alternative to these investments is the adjustment of (local) consumption to (local) production, given there is enough load for this kind of demand response.[2]

Combined with measuring and real-time monitoring of electricity flows using information and communication technologies (ICT), these concepts are often seen as the base for ‘Smart Grids’.[3] To realize such visions with an (local and global) adjustment of consumption, generation and storage, the interaction of different stakeholders in the supply chain needs to be coordinated simultaneously using bidirectional communication mechanisms. The implementation of Smart Grids is an evolutionary process and there is significant need for research on technologies and market designs.

The need for actions and concepts can be illustrated with some recent figures from Germany. The installed power capacity of 30.0 GW for wind (WWindEA (2012)) and 33.1 GW for PV (BNetzA (2013)) compared to the minimum and maximum aggregated, national load in a year (approximately 35 GW and 84 GW, respectively) already shows, that even today it may be the case, that the complete load in the country is covered by fluctuating RES-E. However, the system also has to cope with a complete lack of sun and wind energy, so that additional back-up power plants are required. Since a further growth of RES-E is expected, the challenges for ensuring a balance of generation and consumption are getting even more complex. Furthermore, it has to be noticed, that a balance from the national perspective may be ensured, but the ‘local surplus’ in certain rural areas has to be transported to ‘local shortages’ for electricity in urban regions using transmission and distribution grids. Hence, not only the national perspective is important but also the view on certain areas with a pronounced unbalance since the (local) grids have be dimensioned for these power flows. These different perspectives are also relevant for the introduction of storage assets, which have been realized up to now only as large pumped hydro power units. However, decentralized storage systems emerge which may contribute to solve local as well as global (e.g. national) unbalance problems. ETP SG (2010) and EC (2011) state that storage located in distribution grids is indispensable for the integration of RES-E, being also an environmentally acceptable solution.

The extension of transmission capacities with neighboring countries is seen as a contribution to solve the unbalance issue on a wider level (e.g. European area). However, these investments will not be a sufficient solution, since transmission capacities and possible new corridors to neighboring countries are also limited. Furthermore, almost all EU-countries introduced similar laws to increase the contribution of RES-E so that the problem of too much feed-in in certain times of the year and a lack in other periods will not been solved. This is all the more important since the feed-in of wind and PV in the

[2] According to Strbac (2008), demand response has the same meaning as demand side management representing activities to shift load from one period to another period, e.g. to reduce consumption peaks or shift the demand to time periods with lower prices for the electricity consumption (see later in Chapter 5).
[3] The term ‘Smart Grids’ is explained later in detail in Section 2.3.

neighboring countries might have a correlative behavior. An example for such a situation is the need for electricity in the hours without sun radiation (e.g. at night), so that PV cannot contribute to ensure (enough) generation even when enough transmission grid capacity on a European level is provided.

Another aspect which has received growing attention within the last years is that the investments in large infrastructures (such as power plants and transmission lines) increasingly often show up as being not feasible due to the protest of the inhabitants of the corresponding region. These phenomena are sometimes explained as NIMBY- ('Not In My Backyard') or BANANA- ('Build Absolutely Nothing Anywhere Near Anybody') effect. Hence, smart and distributed solutions on a local and small scale are seen as a solution to overcome this problem while still enabling the transition to a sustainable and green electricity system.

As already mentioned, the challenge of matching generation and consumption on the national and European level will become more difficult due to the intention of most countries to further increase the number of installations of RES-E. This challenge is depicted in Figure 1-2 considering data for Germany. Hereby, the scenario a) shows the installation based on expectations of the regulation agency and scenario b) based on expectations of the federal states. The values for the expected, installed capacities and the maximum and minimum load (P_{max}, P_{min}) originate from Dena (2012)).[4] The figure shows that the installed capacities significantly exceed the national load and, due to the growth of PV-, wind and biomass installations, the unbalance issue will grow dramatically in the next decades. Hereby, it has to be noticed that the actual feed-in of RES-E will be lower than the installed capacities due to the diversity effect. This diversity effect is defined as the quotient

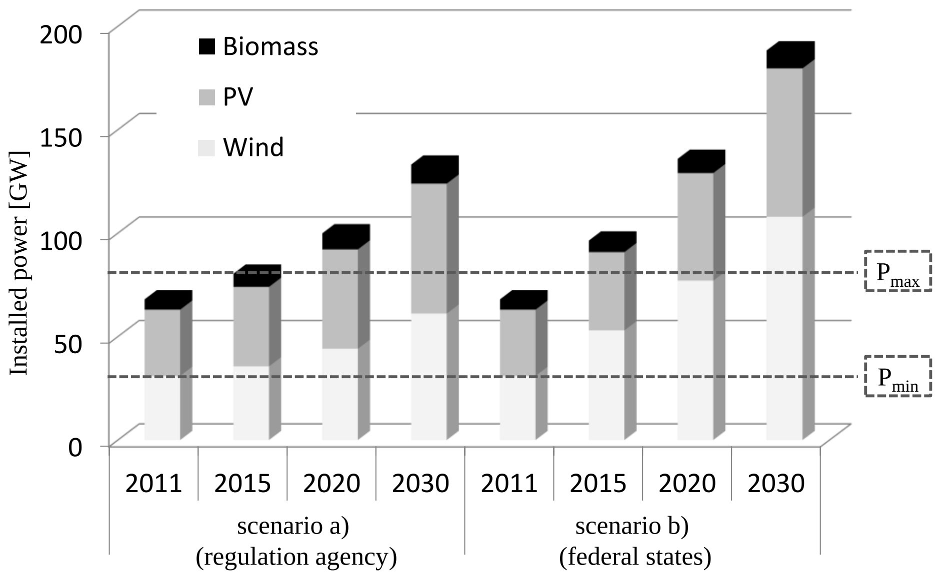


Figure 1-2: Expected Growth of RES-E and min/max load in Germany

[4] It has to be noticed that the values for the load are depicted as being constant since the former mentioned growth of the consumption over one year does not enable a reasonable estimation on the maximum and minimum power values, which is caused, inter alia, by the unknown steering of adjustable devices in future electricity systems.

of actual feed-in and installed capacity. Since not all generators will reach their maximum feed-in at the same time, the actual feed-in will be lower than the installed capacity and hence, a diversity factor <1 occurs. This effect is expected to be more pronounced with a growing number of generators, which will be further analyzed for a RES-E portfolio in a distribution grid area in Chapter 3. Nonetheless, it can be concluded that new concepts for coping with the unbalance of RES-E and load are required. The figure indicates again the importance of storage assets and flexible consumption devices to cope with an oversupply as well as a lack of feed-in out of fluctuation PV and wind generation.

Also for the other countries in the world, significant increases of RES-E installations and shares on total generation are expected. The European Commission simulated different scenarios with a minimum share of renewables in gross final energy consumption (including the segments of electricity, transportation as well as heating and cooling) of 55% by 2050 (today approximately 10%). For the electricity segment, the expected share of RES-E even reaches between 64% and 97%, depending on the simulated scenario (EC 2011). Note that the special attention on and challenges for the electricity supply chain compared to the other energy segments is illustrated again. Furthermore, all these values are reflecting electricity flows over a larger time period, usually an integral of one year. In certain time periods (e.g. with shining sun and blowing wind) and in certain areas the share may differ significantly, so that the dynamics in technical and economic systems are often underestimated when considering such large time intervals.

In recent years, the consumption (demand) has been considered as a stochastic pattern which is inflexible with respect to reactions on short term steering signals. Hence, the generation patterns needed to follow the consumption profiles. Due to the stochastic behavior of PV and wind generation, this may no longer be possible and, therefore, demand may have to react as good as possible on changes in the supply. Note that very large industrial consumers (e.g. connected to the high voltage level) are already able to react to some extent on price signals. However, this is not the case for most residential loads due to a lack of smart meters measuring and transmitting the local consumption, receiving price signals and communicating with adjustable devices to change the consumption patterns of the households. Smart meter roll out has started in a lot of European countries, but still products for the households to participate in the market are missing. Block et al. (2008) state that 50% of the electricity consumption in households is dedicated to appliances which allow a shifting of consumption in time, given that these devices (e.g. white goods, heat pumps) are equipped with suitable soft- and hardware and interfaces to the communication infrastructure. Field tests show a reduction of 10% of the peak power for electricity consumption in a residential area in New Zealand (Gyamfi and Krumdieck (2011)) and of 13% for customers in California, US (CRA (2006)). Frey (2013) displays for a German project a reduction of the peak load of 3-35%, depending on the steering signals and the willingness of households to change the consumption behavior. After a first period of enthusiasm (3 months), these values are reduced but still remain between 2 and 12%. The pilot project presented in Kobus et al. (2013) for a test case in the Netherlands shows that the majority of householders is willing to shift the demand for the consumption devices (in the considered case washing machines) to increase the self-consumption from generated energy of their own PV-modules. The authors further emphasize that the motivations are of different nature, such as environmental issues, financial incentives, interests in advanced and new technologies and the dream to become self-reliant. Hence, activating the flexibility of this residential load is seen as an important contribution to integrate RES-E. However, further research is required in this field to enable a technical, economic and organizational integration of flexible consumption and storage assets in (distribution) grids and markets.

1.4 Contribution

New emerging technologies and the increasing complexity lead to major challenges and opportunities for distribution system operators and the complete electricity supply chain. Hereby, the integration of renewable energies is a dominating driving force. The classical grids will not be able to cope with these challenges and new concepts are to be derived.

In this thesis, real world data of RES-E feed-ins and grid assets forms the base for investigations; via use cases the influence and role of RES-E in distribution grids is studied. Hereby, multidisciplinary views on the electricity supply chain are chosen with respect to the planned increase of RES-E shares on total electricity generation and the occuring challenges for distribution system operators.

On the one hand and with a technical perspective, the feed-in characteristics of RES-E in distribution grids are analyzed in detail. These results enable the appropriate planning of distribution grids. Moreover, grid structures with adjustable consumption devices (such as heat pumps) and storage assets are analyzed. As decentralized storage of electricity is seen as an important contribution for reaching higher RES-E shares, main storage characteristics for an installation in grids and to cope with the feed-in peaks are derived.

On the other hand, economic methods are introduced, e.g. to determine break-even points of storage assets as a substitute to conventional reinforcements or to derive internal rate of returns for investment in innovations considering the special characteristics of an incentive regulation.

Furthermore, the need for adaptions of future market designs is revealed, caused by the increased flexibility of new devices consuming the electricity. The investigations are based on both technical as well as economic considerations. It is shown, that conflicts of interest are likely to occur in future, ‘smarter’ grids and markets since multiple stakeholders are involved and interested in using the potential flexibility of the new assets and technologies. Hence, the interactions and cooperation of stakeholders are required to enable an efficient integration of RES-E. To investigate this, concepts from operational research are used, e.g. to determine optimal storage profiles considering different objectives for the different stakeholders.

The results derived in this thesis can be used on a short-term to improve the integration of RES-E and enable a faster and wider market penetration of storage technologies. For this, the requirements for the storage assets in grids to cope with the feed-in peaks are identified. Moreover, suggestions for adaptions of the regulation systems for distribution grids to incentivize investments in innovations are given. On a long-term perspective, the need for interactions and cooperation of stakeholders in the supply chain is highlighted, which is required for an efficient roll-out of smart meter and smart grid technologies with a more active role of the end-users in the supply chain. Some first basic ideas for implementing such mechanisms for steering decentralized, flexible devices by different stakeholders are provided as well.

The contribution of this thesis is now being placed in the broader context of current research. The European Technology Platform Smart Grids identified main research areas and tasks in the strategic research agenda for the Europe’s electricity networks of the future

(ETP SG (2007)), listed in Table 1-1. Hereby, the contributions presented in this thesis are highlighted according to suitable research tasks.

Summarizing, different aspects for the RES-E integration, from a technical, economic, political-organizational and mathematical (operational research) point of view, are considered in this thesis:

- the feed-in characteristics of PV, wind and biomass generators located in one distribution grid area are analyzed in detail (Chapter 3).
- based on these elaborations, the appropriate dimensioning of storage assets in distribution grids is derived. These new insights in storage characteristics considering real world data are useful for an installation in first pilot projects. The influence of the RES-E technology to be stored (PV and wind) as well as the influence of the diversity factor on these storage parameters are evaluated facilitating the choice of the suitable storage asset for certain situations in the grids (Chapter 4).
- break-even points for storage assets, which are used as a substitute to conventional grid reinforcements, are derived and main influencing factors on the profitability of these substitutive investments are identified and evaluated For this, an economic calculation method is derived taking into account the different cost types and the impact of storage operation in grids (Chapter 4).

Table 1-1: Research Areas and Tasks (ETP SG (2007)) and contributions of this thesis (grey)

Research Area	Research Task
RA 1 – Smart Distribution Infrastructure (Small Customers and Network Design)	**RT 1.1**: The distribution networks of the future – new architectures for system design and customer participation **RT 1.2:** The distribution networks of the future – new concepts to study DG integration in system planning
RA 2 – Smart Operation, Energy Flows and Customer Adaptation (Small Customers and Networks)	**RT 2.1**: The networks of the future – a system engineering approach to study the operational integration of distributed generation and active customers **RT 2.2:** Innovative energy management strategies for large distributed generation penetration, storage and demand response **RT 2.3:** The distribution networks of the future – customer driven markets
RA 3 – SmartGrid Assets and Asset Management (Transmission and Distribution)	**RT 3.1:** Network asset management – Transmission and Distribution **RT 3.2:** Transmission networks of the future – new architectures and new tools **RT 3.3:** Transmission networks of the future – long distance energy supply
RA 4 – European Interoperability of SmartGrids (Transmission and Distribution)	**RT 4.1:** Ancillary services, sustainable operations and low level dispatching **RT 4.2**: Advanced forecasting techniques for sustainable operations and power supply **RT 4.3:** Architectures and tools for operations, restorations and defence plans **RT 4.4:** Advanced operation of the high voltage system – seamless smart grids **RT 4.5:** Pre-standardisation research
RA 5 – Smart Grids Cross-Cutting Issues and Catalysts	**RT 5.1:** Customer Interface Technologies and Standards **RT 5.2:** The networks of the future –Information and Communication **RT 5.3:** Multiple Energy Carrier Systems **RT 5.4:** Storage and its strategic impact on grids **RT 5.5:** Regulatory incentives and barriers **RT 5.6:** Underpinning Technologies for Innovation

- the operations of storage assets and demand response appliances (heat pumps) are modeled from the view point of different stakeholders in the power supply chain. Possible interactions are investigated in detail to reveal the need for adaptions of the future market design to exploit the potential of these new flexible devices and enable a further market penetration with low costs for the complete supply chain and, thus, the whole society (Chapter 5).
- the need for adaptions of regulation methods for distribution grids is shown based on elaborations on the revenue cap regulation, which is used in several countries for the regulation of grid operators. It is shown, that investments in innovations are hampered significantly and incentives are given to avoid RES-E integration or invest in conventional reinforcements (Chapter 6).

Most of the research presented in this thesis is applicable to a lot of countries. However, certain features of the grids, markets and regulation as well as the real world data are taken from Germany, which is a country providing interesting research questions due to the world's leadership in installations of PV and wind generators and the planned closing down of the nuclear power plants until 2022.

1.5 Outline of this thesis

In this chapter a brief overview of the challenges for the integration of RES-E has been given. Hereby, an important factor in the electricity supply chain is the distribution system operator as being the central point for the transition to an electricity production based on decentralized and renewable energy resources. In the next chapter, some background for the research is given. For this, the supply chain is considered in more detail, e.g. to explain natural monopolies and the competitive parts in the electricity system. Furthermore, the technical context given in distribution grids is described.

In Chapter 3, the feed-in characteristics of PV, wind and biomass generators located in a distribution grid are analyzed using more than 2,000,000 measured values. The presented results are important not only for the grid planning and operation in practice, but also for the research presented in further chapters of this thesis.

Chapter 4 deals with the derivation of storage characteristics to cope with the fluctuations in the generation patterns of RES-E. For this, a model of the storage operation in grids is derived to analyze the occurring energy flows in the distribution grid influenced by the usage of storage assets. As mentioned earlier, the storage assets may contribute to reduce global (e.g. national) and local unbalances of generation and consumption of electricity. The focus in this thesis is on local aspects as being relevant in distribution grids. As it is shown later, a usage of the storage assets for further purposes (multiobjective operation) is possible and even recommended to increase the profitability of such investments. The storage characteristics are determined and main influencing parameters are investigated by introducing the measured PV and wind feed-in profiles and varying the number of considered generators (with the feed-in profiles of one and ten generators, whereby the latter considers the diversity effect in the generation patterns). Based on the results derived in this chapter, appropriate storage technologies can be chosen and evaluated against conventional reinforcements, for which the storage assets form a substitution. A use case for such an analysis is presented in Chapter 4 as well. For this, a methodology is derived to calculate break-even points for such investments in storage assets. The methodology is tested on a real grid situation to calculate realistic values for the break-even points and reveal main influencing parameters. Furthermore, an analysis of the storage behavior is provided indicating the flexibility left for the operation of the storage assets if a combined operation with multiple objectives is enabled.

This perspective of interactions and cooperation between stakeholders is taken up in Chapter 5. First, it is investigated how different steering objectives of different stakeholders affect the operation of decentralized storage assets. More precisely, a use case based on the real world values is presented to investigate a battery system on a medium scale (2 MW, 8 MWh). The resulting profiles of the battery system are analyzed depending on the operator steering the storage asset. The available flexibility to store and withdraw electricity from the storage is not only interesting for grid operators to realize a flattened profile and, thus, reduce grid investment costs, but also for suppliers and traders. These stakeholders may use the flexibility to react on price signals, e.g. resulting from spot markets, for arbitrage purposes selling energy at high price periods and buying it, when prices are low. Next to these mono-stakeholder cases, also a combined operation is analyzed, whereby arbitrage is used as the main goal, but grid constraints are taken into account.

In a second main part of Chapter 5, a use case considering the grid planning with heat supply provided exclusively by heat pumps is presented. Hereby, the heat pump is an adjustable appliance, which is able to shift the demand for electricity due to a connected heat buffer and an inert floor heating system. The buffer provides flexibility because consumption of electricity and demand for heat can be decoupled to some extend in time. A residential area with 102 households and real smart-meter data for the electricity consumption of households and heat pumps are taken into account, so that required grid structures for the connection of the households can be determined. As shown in the study, the grid structures (e.g. number and type of installed cables and transformers) depend also on the steering method for flexible consumption devices (i.e. heat pumps in the analyzed use case). It is investigated, how different steering methods affect grid costs and whether an introduction of demand response without considering grid constraints is advisable from a welfare point of view or not.

This welfare perspective considering the system as a whole is important to enable an energy transition with reasonable costs. However, also the view on single parts of the supply chain is required to analyze whether or not these stakeholders are incentivized to participate in the process and enable the efficient and effective integration of RES-E. Such a perspective is chosen in Chapter 6. For this, the focus is on the regulation system for distribution grids. It is examined if there are any incentives to invest in innovations such as storage systems, voltage regulation appliances or increased demand side management from a grid operators' perspective. For this, a methodology is introduced enabling the calculation of the profitability of new investments and existing assets in incentive regulations. This methodology is applied to a use case considering the data of 50 distribution system operators. The simulations include efficiency analyses of the grid operators which are required for evaluating the different investment strategies on the profitability of the grid investments and for revealing main influencing parameters. As in the former chapters, a discussion is started in this chapter providing ideas and suggestions to enable a more efficient integration of RES-E and adjust the power system to future needs.

For the sake of clarification and to provide a general overview, Figure 1-3 positions the different research areas in a wider context. Hereby, the outline of the thesis with the corresponding numbers of the chapters is depicted. Furthermore, the interaction of the different research scopes is illustrated.

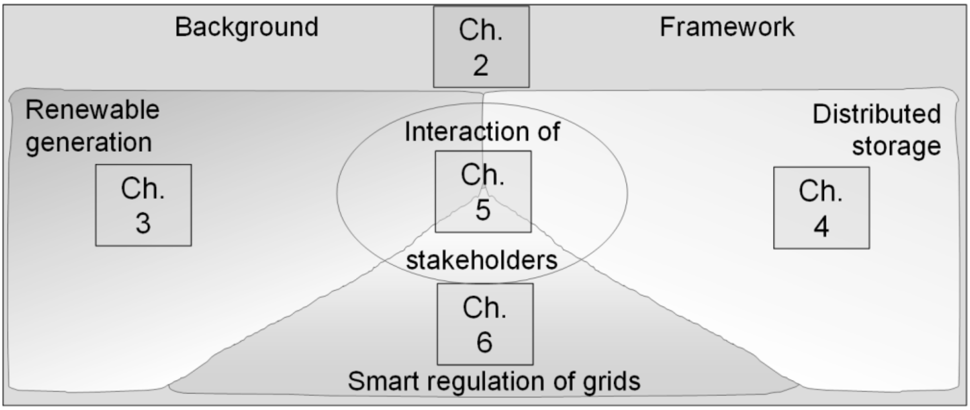


Figure 1-3: Outline of the thesis

2 Background

Abstract - *This chapter gives some background information of electricity markets and distribution grids. Hereby, the electricity supply chain is considered in detail to get a picture of the framework where generation companies, suppliers, traders and grid operators are working in. The transition of vertically integrated organizations to a disaggregated supply chain is explained. In more detail, the characteristics of a natural monopoly are given followed by an analysis where such natural monopolies can be found in the supply chain and where competition of market participants is possible. This short overview of economics in the electricity supply chain is relevant for understanding and positioning the research described in the following chapters, e.g. with respect to the role of different stakeholders in the supply chain; hereby the analysis is given with a focus on the perspective of the distribution system operator.*

Since the main focus of the research presented in this thesis is on the operation of distribution grids and the challenges occurring with the integration of renewable energy systems and new consumption devices, an explanation of the technical context given in these grids is given. Based on these elaborations on the main requirements of grids, the technical challenges in distribution grids occurring with generation, consumption and storage are facilitated. Furthermore, the term 'Smart Grid' is further explained, including the perspective, the benefits and the efforts required to realize the transition of the current system to a smarter alternative.[5]

The electricity supply chain has faced a lot of changes in recent time and fundamental developments are expected in the coming years. These changes are taking place in several dimensions.

First, the organizational dimension is relevant due to the changing market designs inducing different economic frameworks for the different actors in the supply chain. The vertically integrated electricity organizations have been split up in most countries, so that the 'classical' market roles of generation, supply, transmission and distribution are attributed to different companies. In a lot of European countries, this process of liberalization and unbundling went along with the process of privatization. The main reasons for these politically induced actions are explained in Section 2.1. Furthermore, characteristics of natural monopolies are described as well as an investigation and discussion, where these characteristics nowadays can be found in the electricity supply chain. Since natural monopolies need to be regulated, different methods of regulation are described focusing on the commonly used incentive based regulations with revenue/price caps as well as the yardstick regulation. This disaggregated structure of the electricity supply chain, differentiating it in a competitive and non-competitive part (natural monopoly), results in a "post-liberalized" supply chain. Hereby different market roles are active with different optimization objectives and interfaces to other parts of the supply

[5] Parts of this section are from [Ny:1], [Ny:3], [Ny:4].

chain. For example, traders try to exploit price spreads (arbitrage transactions such as buying electricity in low price periods and selling it when prices are high) and generation companies try to maximize profits by selling electricity with high prices and reduce the costs for the production. The different markets for electricity are shortly presented in a further section, as this information is useful for understanding the perspective of the energy trader in the use cases (e.g. in the Sections 5.2 and 5.3).

A second aspect of the transition of the electricity system is given by the technical dimension. Since the focus of the research presented in this thesis is on the challenges in distribution grids, a brief insight in the technical background of these grids is presented in Section 2.2. For this, the technical transition of the electricity system characterized by unidirectional power flows with demand driven generation to a system with bidirectional power flows with an increased generation oriented consumption is explained in detail. The constraints in distribution grids which are relevant for the technical integration of RES-E and adjustable consumption devices are described and the background for dimensioning assets in distribution grid is discussed. This information is useful for the understanding of the economic and technical issues in the use cases described in the next chapters.

In Section 2.3 the ‘Smart Grid’ vision is discussed in more detail. Appropriate definitions are given, so that this commonly used term is better specified. Furthermore, a literature review is provided dealing with estimations on the benefits of and the costs for the introduction of smart grids.

2.1 Economics in the electricity supply chain

The value of electricity for end users is given by the value attributed to it for operating devices, meaning that electricity has an indirect value. Hereby, electricity can be used for various applications, such as lightning, electrical actuation (e.g. the motor in electric vehicles), heat generation (e.g. instantaneous water heater), computation or communication.

When turning on a device in a household (e.g. a washing machine), the required electricity needs to be provided at that time and transported to the device using grid assets. For this, appropriately designed generation devices as well as transmission and distribution grid assets need to be operated and economic transactions have to be performed. Some of the special characteristics of the electricity sector already have been explained shortly in Section 1.1. In this section, the economic framework for the supply chain is described in more detail. Based on the historical system of vertically integrated organizations, the process to liberalization is explained (Subsection 2.1.1). The characteristics of natural monopolies are derived in Subsection 2.1.2, followed by elaborations on regulation methods (2.1.3), forming the base for the understanding of the post-liberalized supply chain (2.1.4). Furthermore, the markets relevant for the later presented use cases (e.g. for the explanation of prices in spot markets) are described in Subsection 2.1.5.

2.1.1 The way to liberalization

The supply chain for the generation, transportation, distribution and retail of electricity was historically seen as a natural monopoly, and hence, the complete system was supervised or even owned and operated by national governments. Starting from liberalizations in the USA and Great Britain, efforts for a separation of the different parts of the supply chain have been determined all around the world. As main objective for the European liberalization, an increased competition in competitive parts of the supply chain and the reduction of inefficiencies as well as the idea of forming the basis for a single European energy market have been stated (see, e.g. Jamasb and Pollitt (2005)). Hereby, the liberalization of the electricity sector was part of a wider trend toward liberalization and privatization, so that the involvement of the state in infrastructure industries got reduced (Schneider and Jäger (2003)) and competition is now enabled in the parts of the supply chain, which do not inherent the characteristics of a natural monopoly (see more details on the elaborations of the natural monopoly in Subsection 2.1.2).

In general in the economic theories, it is recommended to give the market forces maximum power and reduce the state intervention (like regulation) to a minimum to increase the efficiency of the sector, given that no market malfunctioning is present (cf., e.g. Demsetz (1968), Vickers and Yarrow (1988), Jamasb and Pollitt (2000), Brunekreeft (2003)). Hence, only the parts in the supply chain classified as natural monopolies should be regulated since state intervention in the other (competitive) parts of the supply chain is unnecessary and can be harmful for market results. According to microeconomic theory, competition and the goal of making profit lead to internal (production) and external (market) efficiency resulting in lower prices for the customer and the economy (see, e.g. Posner (1974), Jamasb and Pollitt (2005)).[6] Hence, a differentiated view on the electricity supply chain is preferred, separating the supply chain in a part which can be treated as a competitive market and a part which is characterized as a natural monopoly. This disaggregated approach foresees regulation only for the natural monopoly (see, e.g. Knieps and Brunekreeft (2008), Andor (2012)). For the liberalization of the supply chain, one or more of the following inter-related steps are required: sector restructuring, introduction of competition in wholesale generation and retail supply, incentive regulation of transmission and distribution grids (see more detailed in Subsection 2.1.3), establishing an independent regulator and privatization (Jamasb (2002), Newbery (2002)). Hereby, sector restructuring implies the unbundling of vertically integrated activities along the supply chain, so that not only one organization follows one optimization objective for the complete system but this supply chain needs to be disaggregated with different stakeholders in the single stages of the supply chain. Furthermore, reducing the horizontal concentration in the competitive part of the supply chain is crucial to reduce the market power for certain stakeholders in the particular stages (Jamasb and Pollitt (2005)).

These considerations and practical experiences from other sectors and countries resulted in two important EU directives for the electricity sector in 1996 and 2003.[7] The main aspects for implementing the directives in national laws compared to the former market designs are given in Table 2-1. The third package of directives for electricity and gas markets was introduced in 2009 to further foster the unbundling of the different competitive parts from the regulated parts of the supply chain. Furthermore, the foundation of a European agency (ACER) for the cooperation of national regulation agencies and the enforcement of consumer rights was resolved in this third package (which was first already published in EC (2007)).

[6] Note that there exist numerous definitions and dimensions for efficiency in literature. Coelli et al (2005) define among others productivity, technical efficiency, allocative efficiency and technical change (dynamic efficiency), being measured as a ratio of output to input, whereby a higher ratio indicates an increased efficiency value.

[7] Directive 96/92/EC of the European Parliament and of the Council of 19 December 1996 concerning common rules for the internal market in electricity and Directive 2003/54/EC of the European Parliament and of the Council of 26 June 2003 concerning common rules for the internal market in electricity and repealing Directive 96/92/EC.

Table 2-1: Contents of the EU electricity directives 96/92/EC and 2003/54/EC

	Most common form pre-1996	1996 Directive	2003 Directive
Generation	Monopoly	Authorization Tendering	Authorization
Transmission Distribution	Monopoly	Regulated Third Party Access (TPA) Negotiated TPA Single Buyer	Regulated TPA
Supply	Monopoly	Accounting separation	Legal separation from transmission and distribution
Customers	No choice	Choices for eligible customers	All non-households (2004); all (2007)
Unbundling T/D	None	Accounts	Legal
Cross-border trade	Monopoly	Negotiated	Regulated
Regulation	Gouvernement Department	Not specified	Regulatory Authority

Source: Vasconcelos (2004), Jamasb and Politt (2005)

The EU directives were implemented in national laws, e.g. for Germany with a complete revised version of the energy law EnWG (which was first introduced in 1935) in 1998. Amendments have become valid in the years 2003, 2005, 2008 and 2011. Taken into account the long period without changes before 1998, the dynamics also in these legal issues are shown.

Based on the theory of the disaggregated regulation, competition should show up in all non-natural-monopoly-parts of the supply chain. To enable this competition, regulation of natural monopolies is seen as a prerequisite (see Armstrong and Sappington (2006) and Joskow (2008)). To deepen the understanding of the competitive and non-competitive parts of the supply chain, which is important for the elaborations in the next chapters, the characteristics of the natural monopoly are explained in the next subsection.

2.1.2 Natural monopolies

To describe the legislation of regulation, a theoretical background on the characteristics of natural monopolies is presented in this subsection. These elaborations are also useful for the understanding of the current structure of the supply chain (Subsection 2.1.4).

The natural monopoly is specified by a market situation where one supplier provides the complete market with lower costs than several suppliers, who fulfill this task together. Hence, natural monopolies are caused by certain cost structures and need to be differentiated from government-granted monopolies (established by national authorities, e.g. to avoid competition in certain sectors) or cartels (in literature, cartels are sometimes declared as collective monopolies or coordinated oligopoly; cf. details for the context of monopolies in Lerner (1934), Telser, (1960), Posner (1974)).

The cost-structures described previously are specified as subadditive cost functions over the relevant range of output levels and can be described mathematically for the production (output) as

$$C\left(\sum_{i=1}^{m} q^i\right) \leq \sum_{i=1}^{m} C(q^i)$$

where C represents the cost function for producing the output and the values $q_1,...,q_\mathrm{m}$ specify productions quantities (cf. Ströbele (2010)).

As, for example, Evans/Heckman (1984) and Salvanes and Tjøtta (1998) state, these subadditive cost functions are undoubtedly given for electricity grid operators. Furthermore, in the electricity supply chain the electricity grid represents an essential facility or bottleneck, meaning that the usage of the grid assets is necessary for other parts of the supply chain to reach consumers and enable a business relationship. In these cases, duplication of grid assets is not a rational option due to unreasonable high costs. Hence, electricity grid operators are (in general) regulated (see, among others, Armstrong and Sappington (2006) and Joskow (2008)).

Possible reasons for the occurrence of natural monopolies are the non-divisibility of production factors and high sunk costs[8] with constant marginal costs.[9] Also economies of scale[10] and economies of scope[11] can be sufficient conditions for the forming and consistence of natural monopolies, depending on the market and company size and the characteristics of the cost functions (cf., for example, Kerber (2007) and Knieps (2008)).

Moreover, high sunk costs act as a market-entry barrier and reduce the opportunity of competition even further. Knieps and Brunekreeft (2008) explain this by the different ways of considering these costs in the decision-making process: the existing company made the investment in the past and cannot use the assets for other purposes (in the same area) or in other geographical areas (with the same purpose). These sunk costs are therefore no longer relevant for future decisions. In contrast, a new competitor has to include the costs in his decision whether to entry the market or not. This leads to a difference in the consideration of these costs since they are only relevant in the decision of the new competitor. The danger of strategic behavior on the side of the existing company manifests in predatory pricing to compete with the new company. Thus, market entry can be excluded if sunk costs have a sufficiently high share on total costs (Knieps and Vogelsang (1982)).

From an economic point of view, it is efficient to satisfy the markets needs in natural monopolies with only one supplier to obtain the cheapest production costs. One problem occurring with this approach is the monopoly power for the one supplier remaining (in most cases the company who developed the market). Several effects (described, for example, in Kerber (2007)) show that negative results will occur: a higher price, a smaller amount of output and/or a non-performance-based profit for the monopolist. A possible solution for these problems is to accept the monopoly, but regulate it to reduce negative consequences.

[8] Sunk costs are costs which already have occurred but cannot be recovered, e.g. for irreversible investments without any use for other purposes or at other locations in the future (cf. Dixit (1991), Sutton (1991)).
[9] Marginal costs are defined as the costs attributed to the next additional produced unit.
[10] Economies of scale exist if a proportionate increase of input leads to an over-proportionate increase of output with the result of decreasing average costs in single output companies (see, e.g. Knieps (2008))
[11] Economies of scope describe the cost advantage due to combining two or more outputs in one firm compared with separate production (see, e.g. Panzar and Willig (1981)).

Hence, market power resulting from the natural monopoly is an argument for state intervention if it cannot be disciplined by (potential) market entry (Brunekreeft (2003)).

2.1.3 Regulation methods

In this subsection, main regulation methods are described which are used in the context of regulating natural monopolies in the electricity sector. These elaborations are useful to understand the special economic background grid operators are operating in. Later on and especially in Chapter 6, these specifics of regulation are discussed in detail, reflected on an implemented revenue cap regulation and investigated in the context of innovations in grids. In this subsection, first the concept of idealized regulation is discussed, which includes a few characteristics (cf. Knieps (2008)):

- the regulation does not cause costs - neither for the regulated companies nor on the regulator side itself.
- the regulator does not have self-interests.
- the regulator is able to ‘correct’ market conditions with the effect, that regulated companies do not have an unjustified monopoly profit and consumers benefit due to lower prices.

Next to this, regulation has to enable the companies to generate appropriate profits, because if the rate of return with a consideration of risk margins falls short of an adequate value (e.g. a comparable market rate), companies will avoid the investment in the infrastructure. Moreover, the asymmetry of information is an essential fact making regulation more difficult: usually, the regulated companies are much better informed than the regulator regarding costs and conditions of demand (Knieps (2008)). An ideal regulation system should consider this asymmetry in an appropriate way.

In recent years a further development of regulation approaches has shown up. Regulation is conceived not only as price-setting-instrument but as a contract between regulator as a principal and regulated company as an agent (Laffont (1994)). The task of regulation is understood as giving the regulated companies incentives for participating in reaching desired goals. These goals may be the maximizing of welfare economics in the context of electricity grids or the efficient or maximal integration of RES-E (which does not necessarily mean the same, e.g. when the maximal integration of RES-E leads to unreasonable costs for the grid operators and the end consumers). However, the regulated companies still do need a self-interest for participation (Knieps and Brunekreeft (2008)). Based on the rethinking of regulation and to reduce disadvantages from previous regulation methods, the used regulation methods have evolved in the last decades. An example for this development is given by the implementation of the rate-of-return-regulation which had been applied in a lot of countries and sectors and which now has often been replaced by incentive regulations. A shortcoming of the rate-of-return regulation was proven by Averch and Johnson (1962), who showed that there exist incentives for regulated companies to deploy too much capital in this cost-based regulation approach.[12] In the context of the privatization of British Telecom, Littlechild made a proposal for a price cap regulation (Littlechild (1982)) - the first kind of incentive regulation. This method was the basis for the regulation of many other natural monopolies in other sectors and other countries in the following years up to the present.

[12] An overview on further, formerly common used methods, such as rate-of-return, return-on-cost, return-on-output and return-on-sales regulation is given in Ströbele et al. (2010)).

The incentive regulation is characterized by the decoupling of costs from revenues within the regulation period and the implementation of *X*-factors describing the potential to raise efficiency. The advantages of incentive regulation are manifested in the inherent incentive to lower costs, because cost reductions which exceed the specified objectives remain as additional profits with the company during the regulation period. In the subsequent regulation periods, these additional cost reductions are passed to the customers in the form of lower prices. In the context of electricity grids, this means that the calculation of grid fees to be paid by the grid users [€/kWh] is enabled principally by dividing the fixed revenues [€] by the expected transported amounts of energy [kWh].[13]

However, incentive regulation also entails a few dangers (e.g. with respect to incentives to invest and innovate, as shown in Chapter 6). For the further explanations and to provide a basis for analyzing these dangers and challenges, the different types of incentive based regulation first have to be differentiated. Hereby, two main forms are relevant - the revenue/price cap regulation and yardstick regulation, whereby the focus first is on the cap regulation. In the progress of the next paragraphs, a basic understanding for the mechanisms of the cap regulation in electricity grids should be provided.

In cap regulations a certain value is specified as the amount by which the grid operator has to reduce its costs in the coming periods. If now the grid operator is able to reduce costs more than this is prescribed by a revenue cap, it can keep the additional profits. However, in case it cannot appropriately reduce the costs, losses occur for the grid operator and even insolvency is possible, showing that the revenue cap surely provides an incentive for the grid operator for an efficient operation and corresponding investment strategies. The consumers benefit by lower prices after the regulation period resulting from the decreased prices. The length of a regulation period is defined by law or an authorized regulation agency. The already mentioned problem of the asymmetry of information and resulting high costs for information procurement on the side of the regulation agency will also be alleviated (Knieps and Brunekreeft (2008)). This is reached by using exogenous and observable values for the regulation and progress of the cap (e.g. size of the supplied area or number of grid-connected households as an output), meaning that these parameters can easily be comprehended. Nevertheless, still a cost determination is necessary for getting the starting level of the cap for the regulation period. In this context also a classification of cost types is needed - it is distinguished between permanent non influenceable costs c_{pni}, temporary non influenceable costs c_{tni} and influenceable costs c_i. The last two types can be specified using a company-specific efficiency value θ assigned to the grid operator (cf. Steinbach and Kremp (2006), Leprich (2009) and the currently implemented regulation formula in the German revenue cap regulation in ARegV (2012)). The separation is necessary since the inefficiency can only be reduced for the costs which can be influenced by the grid operator.

To illustrate this general idea of incentive regulation (which is taken up in Chapter 6 focusing on innovations in grids), an example is given in Figure 2-1. For this, different scenarios of efficiencies and revenue caps are used for two grid operators: both companies have a cost base with total costs c=100 and – as a part of it – permanent non influenceable costs c_{pni}=40. Scenario 1 shows a grid operator with an efficiency θ of 100%. The influenceable costs c_i are calculated as c_i=0, so c_{tni}=60 remain as temporary non

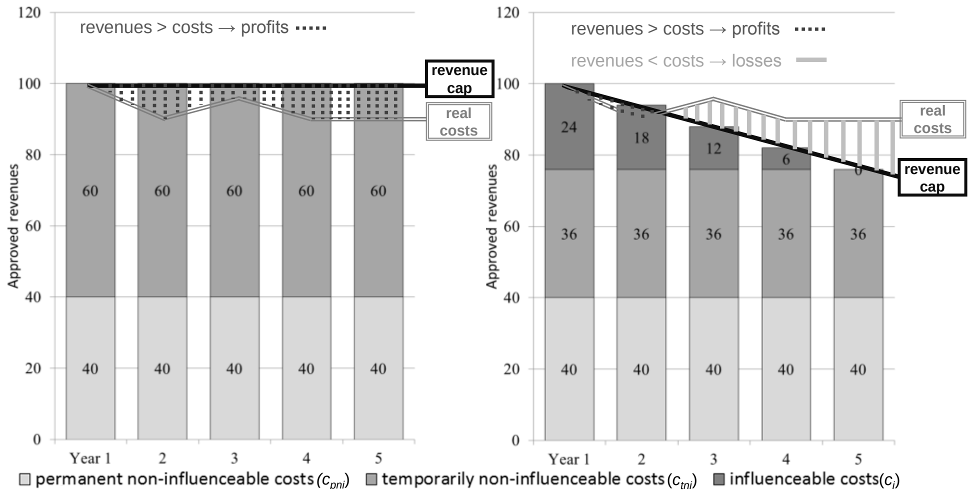
[13] Note that this kind of calculation of grid fees for households is used in a lot of countries. However, in some countries the system has changed, so that the tariffs are not energy-related anymore but refer to the maximum power value a household has used or is able to use, e.g. as implemented in the Netherlands.

influenceable costs (see the calculation in the figure). In Scenario 2 the regulator determines an efficiency of θ =60% for the grid operator, so the calculations give c_{tni}=36 and c_i=24 as shown in Figure 2-1. The influenceable costs c_i are declared as inefficiency costs which have to be reduced to 0 until the end of the regulation period. To force this, a declining revenue cap is used. Hereby, the revenue cap characterizes the maximum revenue a company is allowed to earn in a certain year, whereas the real costs occurring for that company may differ. The progress of the real costs in the regulation period is described by the cost curve. If in both scenarios 1 and 2 the same real cost curve within the next years is given as indicated in the figure, significantly different results occur for the profitability of the grid operators. In Scenario 1 the grid operator has additional profits within the complete regulation period. The grid operator in Scenario 2 has to deal with losses because his real costs curve after some time is above the curve of the revenues. With the starting of the next regulation period, a new cost determination is necessary leading to a new starting point of the revenue cap (c), a new efficiency value (θ) and new cost structures (c_{pni}, c_{tni}, c_i). The consumers benefit from the reduced costs due to the declined revenue cap of the previous regulation period and thus, lower prices. This very simplified example shows the relevance of the efficiency value, the cost types and the duration of the period. Furthermore, the inherent incentive in the regulation method to lower the costs and thereby leading to produce efficiently is visualized.

As indicated in the example, calculating business cases for grid operators operating in natural monopolies requires substantially different tools and approaches compared to competitive markets. When evaluating the investment decision of grid operators to integrate

Scenario 1: efficiency θ: 100%
total costs c = 100
c_{pni}: 40 (identified by valuation of the r.-agency)
c_{tni}: $(c\text{-}c_{pni})\cdot\theta$ =(100-40)·100%=60
c_i: $(c\text{-}c_{pni}\text{-}c_{tni})$=(100-40-60)=**0**
to be reduced within the regulation period.

Scenario 2: efficiency θ : 60%
total costs c = 100
c_{pni}: 40 (identified by valuation of the r.-agency)
c_{tni}: $(c\text{-}s_{pni})\cdot\theta$ =(100-40)·60%=36
c_i: $(c\text{-}c_{pni}\text{-}c_{tni})$=(100-40-36)=**24**
to be reduced within the regulation period.



simplified: without industry-specific progress factor, enlargement factor, inflation, etc.

Figure 2-1: Example for the functionality of revenue cap regulation

RES-E, the previously described regulation methods used by regulation agencies and grid operators have to be considered. This perspective is further explained with a deepened analysis of the investment behavior of grid operators in Chapter 6.

The yardstick regulation can be seen as a further development of the revenue/price cap regulation and is also a form of incentive based regulation. Hereby, the revenues are completely decoupled from the individual costs of the grid operator. This is achieved by defining tariffs and caps based on the costs structures of comparable grid operators (Shleifer (1985)). By this, caps and efficiency goals are linked to the performance of the complete sector. A benchmark is implemented to determine individual efficiency objectives for the grid operators. If a company is able to overperform and reduce costs more than prescribed, additional profits can be generated. This effect shows similarity to the revenue/price cap regulation, but the companies can profit even more from reduced costs and increased efficiency in yardstick regulation: in the following regulation period, the regulator adapts the revenue caps not on the individual but sector-related cost level, so overperforming can be effective beyond the current regulation period (Pielke and Kurrat (2008)). As the individual caps are influenced strongly by performance of the complete sector and a direct comparison of cost structures is given, the yardstick regulation is able to simulate the 'competitive market' quite well compared to the commonly used regulation methods. A basic precondition for implementing this kind of regulation is that all grid operators have a similar efficiency level. Hence, yardstick regulation follows often a foregone period of revenue/price cap regulation (Müller et al. (2011)). Furthermore, the grid operators should be comparable considering cost influencing parameters.

As shown in this subsection, different approaches to regulate natural monopolies are used in practice. An overview is provided in Haney and Pollitt (2009) and Lapillonne and Brizard (2013), indicating that incentive based regulation is implemented for the electricity sector in most European countries. As an example for Germany, the incentive based regulation in form of a revenue cap regulation was implemented in 2009, replacing the former cost-based regulation. In the next subsection, the question which part of the electricity supply chain belongs to the natural monopoly is investigated.

2.1.4 The post-liberalized supply chain for electricity

Within the electricity supply chain several market roles exist with different interests and objectives. Drasdo et al. (1998) state that "generation" is faced with market conditions. Hence, competition should be enabled since regulation in supply chains should be as minimal as possible to improve the efficiency of the sector (cf. details in Subsection 2.1.1). It is argued in Ströbele et al. (2010) that the relation of new (relatively small) power plants to today's (relatively large) market size and compound in the transmission grids are further reasons to not classify generation as a natural monopoly.

However and as stated before, the "grids" have the symptoms of natural monopolies - in particular, these characteristics can be found most distinctive in low and medium voltage level (Drasdo et al. (1998)). Market-entry barriers are very high in these parts of the supply chain since investments have to be seen as sunk costs and no threat of new competitors has to be feared.

In contrast, competition is pronounced in "wholesale trading" and offering of "energy services" (e.g. improving energy efficiency on consumer side). Also the supply of energy ("retail markets") belongs to the 'free market' since no high fixed costs are required for the market entry and economies of scale in relation to the market are relatively small (see, e.g.

Joskow (2008) and Andor (2012)). Hence, (several) electricity suppliers can deliver the consumers with energy using the same grid.

The following comparison can be used to illustrate the market roles – grid operators can be seen as road constructor and maintenance companies. A parallel structure is likely to be inefficient, so one company is responsible for the infrastructure. However, desired market results like lowest prices and best customer services for logistic services can be reached via competition markets. Consequently, the (one) infrastructure company has to enable competition between (several) logistic companies using its roads.

But there are also parts in the supply chain with unclear classification - as to be shown in the following with regard to the Dutch and German frameworks. The inconsistency is particularly given for metering services with the market roles 'operator of measuring facilities' (installation and maintenance of meter) and 'metering service provider' (determination of measured values). These market roles are described in more detail in BDEW (2011). In the Netherlands, metering services belong to the distribution system operator and thus, this function is faced to regulation. In Germany, there is competition with no necessary organizational link to the grid operator. As shown by these two countries, the classification of these roles seem to be controversial – VDE (2010) states that liberalization of metering services and global introduction of smart meter is contrary since the population has low self-interest in smart meter technology and loses the overview with too many contracting parties. It is asked in this study whether too many market roles hamper the achieving of climate objectives, delay the roll out of smart meters and complicate the implementation of smart grids. Similarly, ETP SG (2012) states that the question, which stakeholders shall be regulated in natural monopolies and which stakeholders should operate based on competitive market rules, is critical. This differentiation is increasingly important with new emerging market roles. Note that in Europe, the separate market role for metering services is only given in the United Kingdom and in Germany; in all other countries, the market role is included in the DSO-businesses as presented here for the Dutch system (Hierzinger et al. (2012)).[14]

Furthermore, the classification as an 'essential facility' is undoubtedly given in distribution and transportation grids since there are no opportunities to substitute the grid or enable a business relationship to consumers without using grid assets. The characteristics for the natural monopoly in regard to the subadditive cost structure or the market-entry barriers are fulfilled as well. However, the classification of market roles in 'natural monopoly' or 'competition market' is not that clear for every market role as the case with the metering services has shown. Since the regulation should only be applied for the natural monopoly parts of the supply chain, the essential question is what is minimally required for being regulated and how other political objectives, like e.g. supporting the smart meter roll out, can be included in the choice of the market design.

Figure 2-2 shows the existing market roles and their classification in competitive or regulated parts of the supply chain. The generation from conventional power plants or larger renewable energy parks (wind, photovoltaic (PV)) is measured (metering role) and the energy is transported via transmission and/or distribution grids. An important fact is the possible bidirectional flow between distribution and transmission grids. Meanwhile, this effect occurs often with lots of decentralized generation connected in rural distribution grids. In the past, the energy flow always emanates from conventional generation via trans-

[14] Note that the metering service was liberalized in the Netherlands as well and, after starting the smart meter roll out and facing the problems described above, reintegrated in the DSO-business.

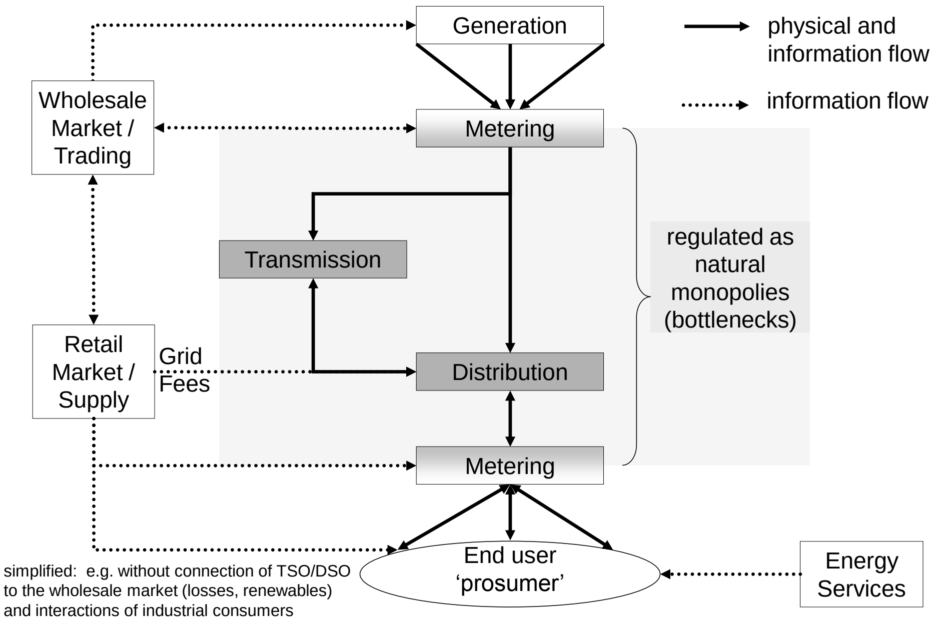


Figure 2-2: Supply chain in liberalized markets

mission and distribution grids to the end-user. Since the end user no longer only consumes energy but also produces it (PV, small wind mills, micro combined heat and power appliances (µ-CHP's)), the bidirectional flow of energy and information is given here as well. Thus, the consumer can be defined as 'prosumer' (Krost, et al. (2011)). The functions "wholesale market / trading" focus on the interaction between the generation and the "retail market / supply". The latter is mainly connected to the consumers and the distribution grid (e.g. to pay the grid fees determined by the incentive regulation). Note that the metering role is depicted in Figure 2-2 disproportionate large with respect to the little revenues gained in this function or the small number of employees engaged for this work compared to the other parts of the supply chain. Instead, the figure indicates the attribution of the functions to the competitive or related parts of the supply chain and, due to the contradicting views in different countries, a special focus on the metering role is required as given in the figure. Summarizing, the non-grid related roles operate in a competitive framework. For the progress of this work and to understand the interaction of the market roles and the price formation for end-users, the next subsection provides a short overview on the markets for electricity.

2.1.5 Markets for electricity

The supply and demand of electricity is economically brought together in electricity markets by the determination of an equilibrium price p_e. This process may take place at the wholesale market where available amounts of electricity generation are placed by trading companies. The cost function of the supply at the market is derived from the short-run marginal costs of the power plants. The offers are given in an ascending order, so that the generation types with the lowest marginal costs are used primarily (cf. Jamasb and Pollitt

(2005), Ströbele et al. (2010), Andor (2012)).[15] This mechanism is called merit order and depicted schematically in Figure 2-3. Typically, the resulting generation fuel mix leads to a primarily usage of hydroelectric and fluctuating (PV, wind) power generation as well as nuclear power due to their low marginal costs (see, e.g. Sensfuß et al. (2008)). However, the merit order system is a static system and fixed costs of the investments for the power plants are not considered (hence, the underlying market scheme for the merit order system is also called an 'energy only'-market). In recent years, the contribution margins to cover the fixed costs have been gained in times where the equilibrium price exceeded the marginal costs of the power plants. As a consequence of the large amounts of feed-in from fluctuating generators and due to the lack of storage capacities, a flexible generation park is needed to ensure timely up and down operation of the conventional power plants (such as coal and natural gas). In these seldom situations of operation, these power plants are often not able to gain the contribution margins required to cover the fixed costs and hence, it may be rational for the investor and operator to leave the market and shut down the power plant. It is discussed in literature and in practice to adopt the merit-order system, so that conventional power plants are paid for serving as back-up power plants in case of a lack of feed-in of fluctuating RES-E feed-in (leading to 'capacity markets', cf. Cramton and Stoft (2005), Nikolosi and Fürsch (2009), Milligan et al. (2012)). However, this important discussion is not the scope of the research presented in this thesis.

For the background of the discussions described in the next chapters, it is important to consider the mentioned price determination and to differentiate between the different types of markets where supply and demand can be matched. The markets can be separated in time with respect to the financial transaction (contract between the parties) and the actual, physical fulfillment. Hereby, the energy markets can be differentiated as follows:

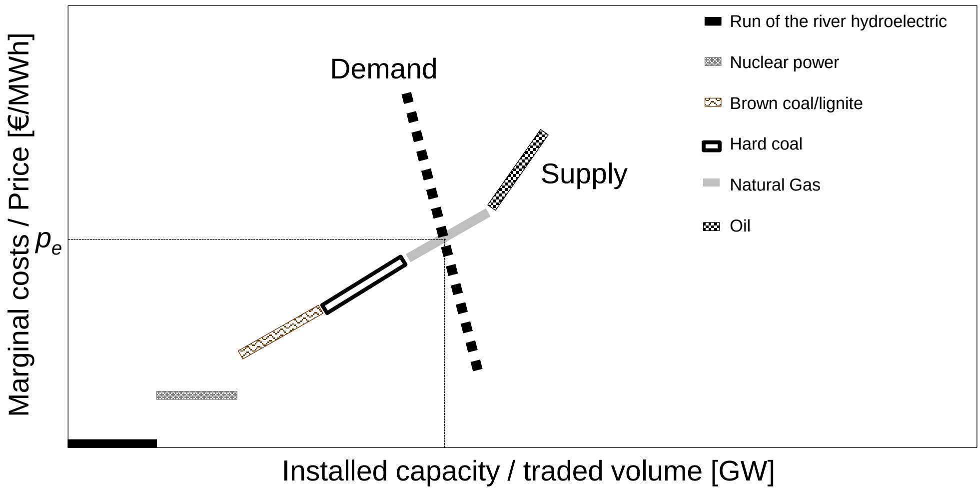


Figure 2-3: Example for a merit-order (schematically)

[15] Note that several countries have implemented a priority feed-in for RES-E. Hence, RES-E is seen in this case as a must-run capacity, although marginal costs may be higher than the equilibrium prices (e.g. for biomass generators, which have to consider their variable costs, e.g. for raw materials). For this case of feed-in tariffs and priority feed-in, RES-E is not completely included in the market mechanisms. This is further discussed in the Chapters 3, 5 and 7.

- long-term markets: business transaction and the actual delivery do not take place at the same time; a gap of months and years is possible. Typical products are Futures, Forwards and Options.
- spot markets: day ahead (up to one day in advance) and intraday markets (up to one hour in advance) are handled (almost) immediately. These markets and the resulting prices are considered in use cases in this thesis (see Section 5.2 and 5.3).
- control and balancing markets: to ensure a short-term (physical and economical) matching of demand and supply at any time, a target/actual comparison is required. For this, e.g. the transmission system operator can call for tenders to increase or decrease the feed-in of generators and avoid blackouts (see for more details on the different markets, Ströbele et al. (2010)).

The transactions can not only be performed by trading on energy exchanges, such as APX (Amsterdam), EEX (Leipzig) or PowerNext (Paris) but also by bilateral contracts (Over-The-Counter-Business (OTC)). Further interactions, e.g. to meet the schedules of power consumption and generation of a supplier in a balancing group within a transmission grid area, are important for a physical and economic functioning of the grid and of the market, but not primarily relevant for the next chapters focusing on the challenges in distribution grids.

The demand in electricity markets is characterized by a relatively low flexibility. More precisely, for short-term changes in the supply (e.g. due to fluctuations of RES-E feed-in) the aggregated demand is not able to react accordingly due to the inelasticity of demand in electricity markets (see, e.g. Stoft (2001)). The low price sensitivity is also caused by the lack of smart meters and products to react on price signals and especially given for the electricity demand of smaller consumption units such as households. In Figure 2-3, this is indicated by a very negative gradient of the aggregated demand curve. Furthermore, the demand is influenced significantly by daytimes, day type (e.g. weekend or working day), weather, etc. In Smart Grid visions (see more detailed in Section 2.3) the system is intended to be changed, so that a more active role of demand (e.g. households) is aspired enabling a reaction of flexible and adjustable consumption devices (e.g. heat pumps) on short-term changes in the supply. This demand-side response is a topic in this thesis (especially in Chapter 5) and induces new challenges, risks and opportunities also for distribution system operators.

The previous subsections described the economic and organizational framework grid operators and other stakeholders in the electricity supply chain are operating in. The focus of the next subsection is on the technical challenges occurring with a growth of decentralized RES-E and with an increase of adjustable consumption devices in distribution grids.

2.2 Technical issues in distribution grids

As stated in the previous sections, the distribution grid is faced with new challenges by new consumption and generation appliances. To describe the main important technical issues in distribution grids, this section is divided in two parts. First, the technical system and the main requirements to be considered in distribution grids are explained. In Subsection 2.2.2 some ‘smart’ solutions and developments to appropriately integrate these new generation and consumption devices are briefly presented.

2.2.1 Technical transition of the electricity system

The technical transition of the electricity system is characterized by a change from a system with unidirectional to bidirectional energy flows. This paradigm shift results in a transformation of the complete system and requires adaptions in almost all parts of the supply chain, especially with respect to the technical perspectives. The transition of the system is illustrated in Figure 2-4. Historically, electricity was produced in large power plants like nuclear or coal-fired power plants. Physically, it then was transported from the plants via the transmission grid (380/220-kV) and the distribution grid to the end-user, in one direction only. Nowadays, RES-E is connected to all levels of the distribution grid, depending on the capacity of the plant and the grid itself. As a consequence, in several distribution grids, the direction of energy flows has changed in certain time periods. A bidirectional flow occurs if local distribution grids are faced with more feed-in than consumption and transmission grids have to take the surplus energy and transport it to other consumption areas. This effect is depicted in Figure 2-4. Furthermore the main new technologies occurring in the system such as photovoltaic (PV), wind and biomass generators are positioned in this figure. Note that the highest voltage level is connected to other highest voltage grids (e.g. crossing national borders) and further distribution grids and hence, it may be used to transport the surplus energy occuring in certain time to other regions facing a demand for electricity. Also on the demand side, new consumption technologies such as electricity charging stations for electric vehicles and adjustable residential devices such as white goods (washing machines, dish washers, fridges, freezers, etc.) are emerging. Furthermore, the number of installations of local storage assets in distribution grids is increasing (heat buffers, e.g. with heat pump systems) or expected to grow dynamically in the near future (e.g. battery storage systems).

To support decentralized RES-E, several laws have been introduced, forcing distribution system operators to connect the generators, transport the energy and, if required, reinforce grid assets to enable further RES-E operation. For example, the Erneuerbare-Energien-Gesetz (EEG) was introduced in Germany in 2000, with its latest amendment in 2011. According to the Global Status Report of REN21 (2011), similar laws (e.g. with feed-in tariffs) have come into force in 57 countries. Furthermore, laws to support cogeneration of heat and electricity have been introduced, increasing number of the installations of µ-CHPs (micro combined heat and power appliances) in households.

At first glance, it may seem that the introduction of decentralized RES-E reduces overall grid losses and improves asset usage if this energy is consumed in a generation-orientated manner such that no transport over long distances is necessary. However, this scenario is only realizable if the grid assets, RES-E and consumption devices are adjusted and coordinated at any time, which is currently not the case. Especially in rural distribution grid areas with low short-circuit power[16], RES-E can cause problems in the voltage quality and the supply security. One reason for this is that the distribution grid needs to be designed for the maximum peak occurring and hence, it may not be sufficiently dimensioned for the transportation of large amounts of energy in the direction of higher voltage levels. A further reason is the lack of synchronization of the local consumption devices with the local generation devices. In this context, demand side management may provide a contribution to

[16] The short-circuit power is an indicator for the robustness and performance of the grid design at a certain point. It is defined as the maximum power occuring in case of a fault at the relevant node in the grid. There exist numerous standards and calculation approaches to determine the short-circuit power, e.g. IEC Standard 909 is based on the calculation of symmetrical short circuit currents (cf. Nose and Sakurai (2000)).

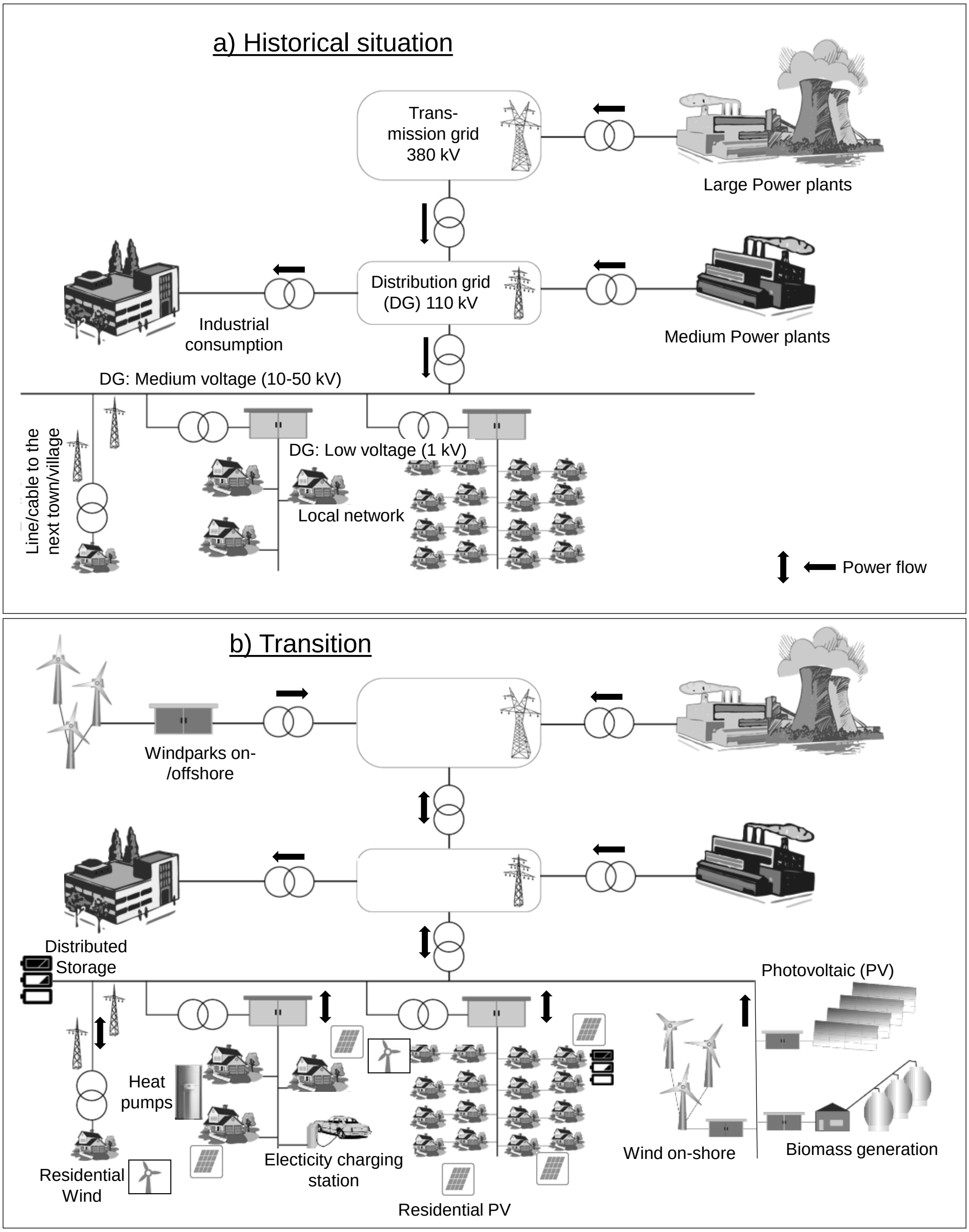


Figure 2-4: Technical transition of the electricity system

solve local grid problems, but it has not yet been implemented sufficiently. Furthermore, the availability of a sufficient number of appropriate devices, especially in rural areas, is often not ensured.

Generally, the grid assets like cables and transformers have to be designed for worst-case scenarios in the grid. The main hard requirements for dimensioning the distribution grid are:

- the limits for the stress (current) of grid assets. Exceeding the asset-specific value for the current carrying capacity (ampacity) causes damages to the assets themselves. This situation is avoided with protective mechanisms which may interrupt the current flow.
- the permitted voltage of public supply. These limits are defined e.g. in the European Norm 50160. The violation of threshold values may cause damages to connected consuming and generating devices, e.g. in the households. In practice, the voltage magnitude variation is the most important of these values. The threshold for the voltage value is defined as ± 10 % of the nominal voltage.

When transferring electricity, both of the described parameters, ‘stress of assets’ and ‘voltage values’, are affected, so both hard requirements are of importance. The stress on the grid assets is caused by the current flow and the transportation of electricity - this applies for both energy flow directions (see Figure 2-5). Thus, the grid assets have to be dimensioned for the maximum ampacity occurring. Furthermore, as soon as a load is connected to the grid, a voltage drop occurs (cf. for example Barton and Infield (2004), Cutsem (2000), Liu et al. (2004)). In contrast, if a generator produces a feed-in, the voltage value in the corresponding distribution grid rises. As a consequence, the voltage value is influenced by the amount of local consumption and the generation as well as by the electrical characteristics of the installed grid assets (because e.g. of their ratio of resistance to reactance; cf., e.g. Cutsem (2000) and Rodrigues and Resende (2012)). The distribution system operator has to take care that all consumers are supplied with valid voltage values at any time and has to adapt grid assets such that an exceeding of the maximum allowed ampacity does not occur.

The local voltage values may be reduced by extra local consumption, local storing of electricity or additional grid assets increasing the short circuit power. If, for example, local generation exceeds the local load, a load reversal occurs, meaning that the energy is transported from the corresponding distribution grid to the next upstream grid operating at a higher voltage level. In case of load reversals, next to the increased voltage values in the distribution grid also the stress of the used grid assets (cables, transformer) has to be taken into account, especially in the case of higher current flows for the feed-in case compared to the historical supply situation. For the sake of clarity, these relations and scenarios as well as possible solutions to cope with the integrations of RES-E are visualized schematically in Figure 2-5. In Scenario 1 a scenario with load reversal is presented leading to increased voltage values. In contrast, the ‘historical’ load situation occuring e.g. with absent sun and increased consumption in Scenario 2 is characterized by a decreased voltage value (voltage drop), meaning that in general both energy flow directions are relevant. With growing operation of fluctuating RES-E capacities, impermissible voltage and stress values may occur. This can be avoided with an adjustment of feed-in and loads leading to a local balance in the distribution grid (e.g. by applying demand side response or letting power flow into storage assets, see Scenario 3). Alternatively, a reinforcement of the grid assets may lead to a situation where all possible energy flows can be handled (e.g. with additional cables and stronger dimensioned transformers, see Scenario 4).

The reinforcement with additional assets cannot be avoided if the grid capacities are insufficiently dimensioned for large load reversal flows and if there are no opportunities to permanently ensure a local matching of consumption/storage and feed-in. Summarizing, two main scenarios are of interest for investigating the restrictions and capability in distribution grids:

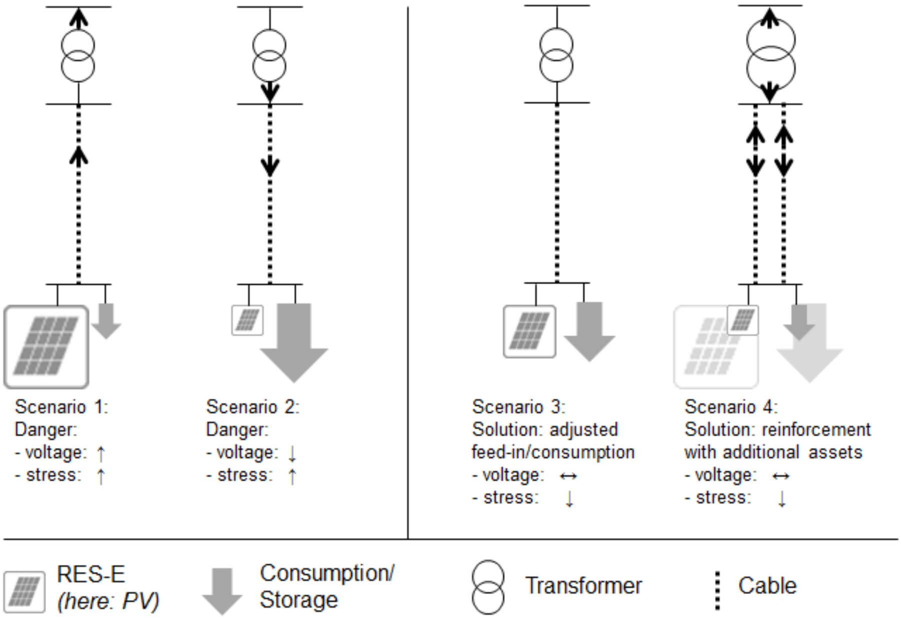


Figure 2-5: Effect of RES-E in distribution grids

- Low-load period: In this scenario the grid is faced with high feed-in and low consumption (load). The occurring load reversal can be accompanied with high voltage values near the RES-E generators and increased stress of assets. The grid operator has to ensure voltage values below the maximum allowed voltage value and usage rates of the assets below the maximum limit for the stress. In such situations, additional feed-in can lead to (intensified) critical situations since the voltage and the stress (due to higher current values) is increased even more (see Scenario 1 in Figure 2-5).
- High-load period: In this scenario low feed-in may be accompanied with high consumption (load). Again, the stress of the grid assets has to be considered. Furthermore, low voltage values occur which have to be above the minimal allowed voltage value. In such situations, additional feed-in improves the situation in the local distribution grid since the voltage value increases and stress of assets is reduced, since lower current values pass the grid assets.

These two briefly described scenarios show the need for identifying the minimum and maximum feed-in which may occur for different RES-E technologies as well as for identifying feed-in profiles over a larger time period (e.g. one year). Based on such data the ‘optimal’ dimensioning of grid assets for reinforcements can be derived (see more detailed and based on real world-data in Chapter 3).

In future grids, especially the voltage increase resulting from decentralized RES-E in low load periods is of importance due to the growing RES-E amounts (as it is shown also in the case studies, e.g. in Subsection 4.5.3). A scheme for this situation and the occuring challenges in the distribution grids is depicted in Figure 2-6. For the sake of clarity, the permitted load values for assets are not shown in the figure. In the historical situation without RES-E, the usual voltage drop occurs as soon as a load is connected to the grid.

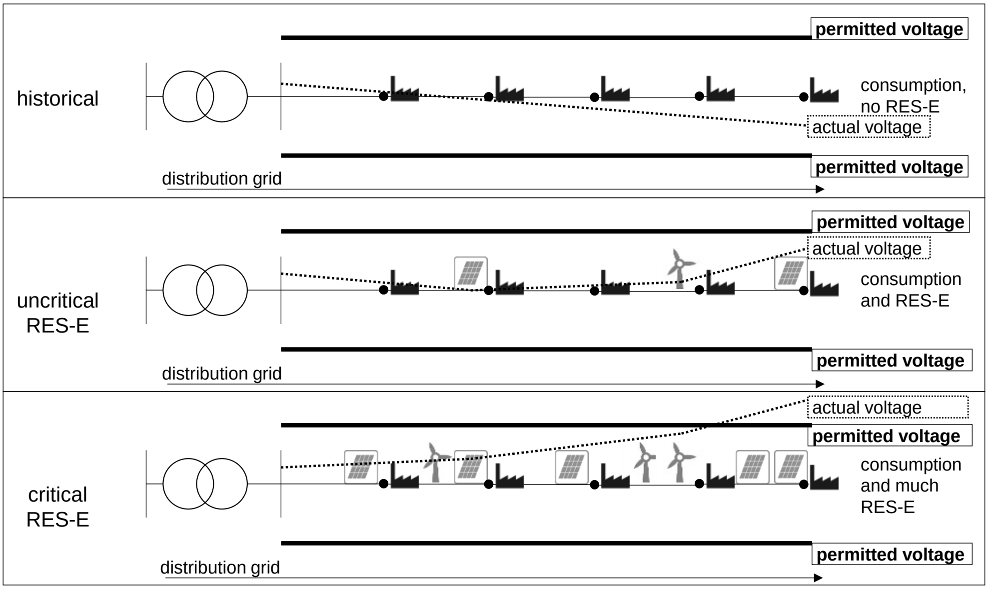


Figure 2-6: Voltage situations in distribution grids with RES-E

The feed-in of decentralized RES-E increases the voltage values which, in a first step, can even help to compensate for the voltage drop experienced by the end-users. However, if too much RES-E is connected or grid assets are not sufficiently dimensioned for these energy flows, the permitted voltage band is exceeded. If in the last years a situation like sketched in the 'critical RES-E' case in Figure 2-6 occurred in grids, a conventional reinforcement (e.g. with additional and/or stronger dimensioned cables and transformers) was conducted to increase the short-circuit power at the relevant places enabling the transport of RES-E amounts with a lower voltage increase. This investment is often called the 'copperplate' scenario. Note that the increase of short-circuit power and the ampacity of grid assets is only needed for the seldom time periods where the peaks of RES-E generation occur, e.g. at times when all connected RES-E generators simultaneously produce electricity and a high feed-in is occuring. A further disadvantage of the copperplate solution is that the peak remains at high grid levels (i.e., it gets 'transported' to and via the upstream voltage levels) and that the grid assets are used less efficient, as they are now dimensioned for this peak.

As stated in Chapter 1, estimations for this reinforcement needs for the integration of RES-E in Germany amount to 27 billion € until 2020 (e-Bridge (2011)) and up to 43 billion € until 2030 (Dena (2012)). Furthermore, Figure 2-6 indicates that next to the size of the generator also the location is relevant - the larger the distance to the transformer, the lower the short-circuit power in distribution grids (such as medium and low voltage levels) and hence, the more pronounced the effect of decentralized generation on the voltage value.

In order to integrate decentralized RES-E into the grid and obtain permissible voltage and load values for the assets, several alternatives to the conventional reinforcement are possible. These 'smart' alternatives are briefly discussed in the next subsection. The technical benefits are explained to provide background information for the analysis in the next chapters and understand the possible advantages of these solutions.

2.2.2 'Smart' alternatives to conventional reinforcements

'Smart' solutions are investigated in literature and practice as possible alternatives to conventional reinforcements for coping with the massive investment requirements. Hammerschmidt et al. (2011) develop a biogas storage system to buffer RES-E and balance the feeding of biogas and PV generators. In Barton and Infield (2004), Delille et al. (2009) and Westermann et al. (2008), several battery systems with corresponding technical data and the associated advantages, when installed in the grid, are presented. Redox-flow-batteries and NaS-high temperature batteries seem to be technically promising, as the fluctuation of renewable energies can be compensated and energy can be stored at places near generation. Hence, later consumption is possible without transportation, given that there is potential consumption near the generation. In Spahic et al. (2011), a technical set-up using a lithium-ion battery and voltage control is presented. De Groot et al. (2013) introduced a lithium-ion battery in a substation in a Dutch distribution grid to manage the energy flow passing the transformer. Moreover, the battery is tested to reduce the grid losses and maintain the supply of end-users in the low voltage grid in case of black outs in the upstream grid levels. Since the introduction of storage in distribution grids is one of the main research field presented in this thesis, an overview on further technologies, advantages and disadvantages with a wider review on current literature is provided in Chapter 4.

Veldman et al. (2009) state that local load management with non-time critical loads (e.g. thermal processes such as air conditioners, heating, cooling, etc.) is also an appropriate approach for exploiting distribution grid potential. For this purpose, also the implementation of information and communication technology (ICT) is required. Next to the possibilities, also the responsibility for steering these non-time critical loads as well as for the operation of storage assets is of importance and will be discussed in detail in Chapter 5. Gwisdorf et al. (2010a) and Gao and Redfern (2010) present innovative concepts for integrating RES-E with voltage regulation appliances, in combination with intelligent steering approaches based on measured voltage values in the grid. This set-up enables the increase of RES-E in existing grids by exploiting the voltage range more efficiently. Bignucolo et al. (2006) present a grid controller steering the on-load tap changer of the transformer in the high voltage/medium voltage substation and the reactive power production of connected generators to avoid impermissible voltage values in the local distribution grids. A trend in the markets is visible to develop, test and install the technology of on-load tap changers also in substation of medium to low voltage level transformers (Brewin et al. (2011)). Hereby, the ratio between primary and secondary equipment is adjusted dynamically depending on the actual, local consumption and generation profiles. Neusel-Lange et al. (2012) propose a method to first adjust the on-load tap changer on the transformer to influence the bus bar voltage. In case the first step is not sufficient, a second possibility is to change the power factor of the local generators to regulate reactive power and moderate the voltage increase. As a last step active power can be adjusted and hence, the feed-in of RES-E is throttled. Also the wide-area-monitoring, recently used only in highest voltage levels, is tested and partly rolled out in distribution grids. Hereby, the voltage in substations in the medium voltage level is measured and used as input signal for the adjustment of the voltage value at the medium voltage busbar in the next upstream transforming station. Hence, in case of large feed-in and high voltage values at the substations in the medium voltage level, the busbar voltage value is reduced to improve the exploitation of the voltage range (cf. Friedrich et al. (2012)). As a further example, the distribution substation presented by Melnik et al. (2011) combines ‘intelligent’ components, such as power electronics for voltage regulation, an electricity storage system and a measurement system in one substation, to improve the power quality for the connected customers.

In general, the previously mentioned tendencies of establishing more power electronics and using ICT also in the distribution grids (instead of only being introduced in transmission grids) goes along with the ‘Smart Grid’-vision presented in more detail in the next subsection. In recent years, transmission grids have always used ICT to a larger extent to provide a balancing and management role in the supply chain whereas the distribution grids have been designed as a more passive part.

The economic benchmarks for these investments in innovations are given by the investment needed for conventional grid extensions. In the context of this thesis, all of these described alternatives to the ‘copperplate scenario’ are defined as smart solutions, since they require ICT, have to react to changed grid states to ensure reliable supply and integrate RES-E with better grid asset usage and avoid the investment in additional cables and transformers. To judge the potential of smart solutions, not only the direct costs, but also the benefits within distribution grids and the society as a whole have to be considered. For example, different voltage values and asset loads occur when comparing e.g. the storage solutions and conventional reinforcements. Figure 2-7 shows an artificial example of the voltage over one day and the corresponding limits in a distribution grid with high PV penetration. Next to the situation without any reinforcement, the resulting voltage values after installing additional cables (conventional reinforcement) and a storage asset for coping with the PV penetration are presented. The figure illustrates that storage solutions provide additional benefits since they may reduce the problems resulting from high diversity factors and fluctuation, so that the local peak is flattened more effectively than in the conventional reinforcement solution. Hereby, the diversity factor is defined as the quotient of the actual used and the installed capacity. Since PV and wind generation is synchronized by similar sun and wind conditions, high values for the diversity factors are expected in local areas (see Chapter 3). When additional and/or stronger dimensioned cables and transformers are introduced (e.g. in the low voltage level) to remove invalid grid situations, the generated

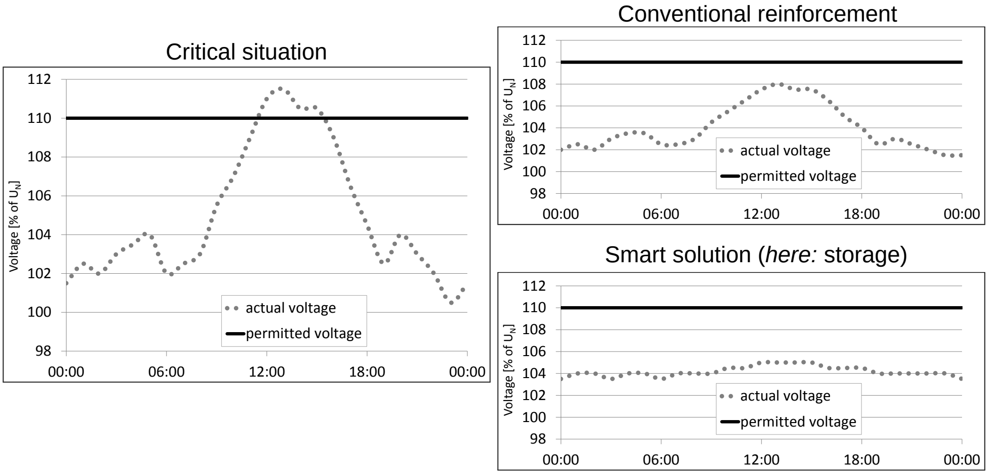


Figure 2-7: Investments for RES-E in distribution grids

power is still transported to upstream grid levels. Hence, the problem may remain on these higher voltage levels, and require action on that level too. This effect applies also for other innovative concepts to integrate RES-E focusing on voltage values, such as on-load tap changers at substations or wide-area-control in medium voltage levels. Hereby, the voltage values are locally adjusted depending on the actual feed-in situations in the grids. However, load values are not affected and hence, peaks are not reduced. In contrast to this, introducing storage assets as an alternative way of reinforcement may also bring benefits to upstream grid levels since the feed-in peak is reduced or even leveled out. This benefit to upstream grid levels in the evaluation of the value of distributed storage assets as a 'smart solution' is considered in the economic calculations in Section 5.2.

For the evaluation of the benefits of smart alternatives further parameters next to the direct attributable costs need to be considered. The additional values may occur through lower losses in the distribution and transmission grid assets and increased usage, better supply quality for end-users, lower costs for backup power plants and less throttling of RES-E. However, the grid operator's investment decision is fundamentally affected by the current regulation, so it is of interest to investigate whether incentive regulation includes (dis-)incentives to innovate. This research question is to be investigated in Chapter 6. The smart solutions described in this section are part of the wider concept of 'Smart Grids', which is explained in the next section.

2.3 Smart Grids - Perspective, costs and benefits

Nowadays, the term 'Smart Grids' is widely used in literature and in practice. Hence, in this subsection appropriate definitions are presented and possible benefits and efforts going along with the establishment of the smart grid vision are described. In this section, the economic framework and market designs (described previously in Section 2.1) and the technical issues in distribution grids (see Section 2.2) are used as background to illustrate the benefits, costs, obstacles and challenges of smart grids.

A commonly used definition of a 'Smart Grid' is provided by the International Energy Agency (IEA):

> *"A smart grid is an electricity network that uses digital and other advanced technologies to monitor and manage the transport of electricity from all generation sources to meet the varying electricity demands of end-users. Smart grids co-ordinate the needs and capabilities of all generators, grid operators, end-users and electricity market stakeholders to operate all parts of the system as efficiently as possible, minimising costs and environmental impacts while maximising system reliability, resilience and stability."* (IEA (2011))

The IEA emphasizes that the 'smartening' of the grid is already happening and not a one-time event. Furthermore, the study highlights the need for realizing more and large-scale pilot projects as well as the requirements for adapting the regulatory and market models. A further definition with a listing of the main objectives is given by the European Technology Plattform Smart Grids (ETP SG), who states:

> *"A SmartGrid is an electricity network that can intelligently integrate the actions of all users connected to it - generators, consumers and those that do both - in order to*

efficiently deliver sustainable, economic and secure electricity supplies. A SmartGrid employs innovative products and services together with intelligent monitoring, control, communication, and self-healing technologies to:

- *better facilitate the connection and operation of generators of all sizes and technologies;*
- *allow consumers to play a part in optimizing the operation of the system;*
- *provide consumers with greater information and choice of supply;*
- *significantly reduce the environmental impact of the whole electricity supply system;*
- *deliver enhanced levels of reliability and security of supply.*

SmartGrids deployment must include not only technology, market and commercial considerations, environmental impact, regulatory framework, standardization usage, ICT (Information & Communication Technology) and migration strategy but also societal requirements and governmental edicts." (ETP SG (2010))

For developing and realizing the concept, ETP SG identified six deployment priorities (DP), depicted in Figure 2-8. Note that all actions mentioned in the figure require the participation of the distribution system operator, indicating again the important role of this function for a transition to a sustainable, green and smart electricity system. Furthermore, the importance of the governance and regulation is highlighted as forming the framework for the market design (in general), e.g. with respect to the interaction of generation, transmission, distribution and selling, and regulating the natural monopolies (in particular), which explains also the relatively detailed elaborations in Section 2.1. According to ETP SG (2010), the activities described in Figure 2-8 need to be completed to achieve results for the European initiatives with respect to the support of renewables, the reduction of carbon emission and the increase of energy efficiency. The Joint Research Centre of the European Commission provides an overview of ongoing smart grid pilots and lessons learned from the different projects in Europe (Giordano et. al (2013). The complexity and challenges with respect to the supply chain is illustrated in ETP SG (2012) with a listing of 20 different market roles as being potential stakeholders in smart grids, such as consumers, prosumers, energy retailers, aggregators, energy service companies, distributed generators, distribution

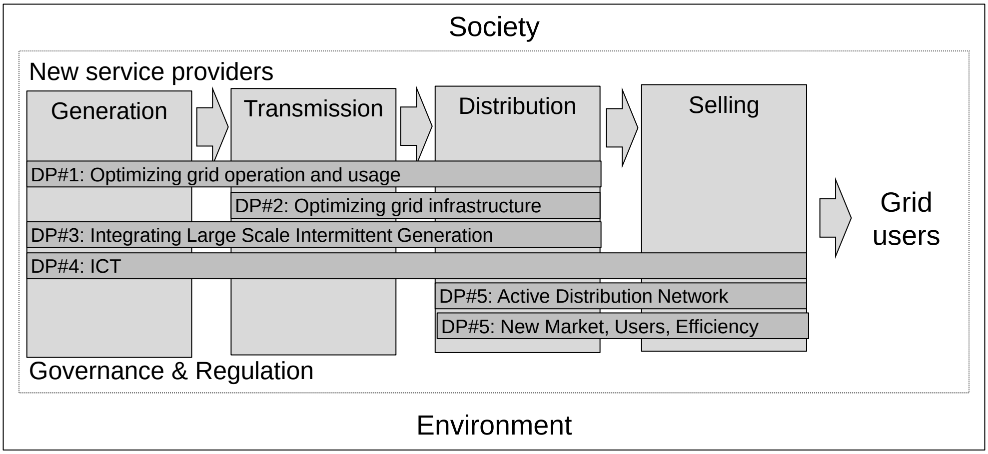


Figure 2-8 : Deployment Priorities for realizing smart grids (ETP SG (2010)

system operators, transmission system operators, storage providers and ancillary service providers.

Scott et al. (2008) call the transition to a smart grid as a third industrial revolution and highlight not only the need for innovations in technology, but also the need for including commercial and regulatory dimensions. A further results presented in this study is the limitation of the “fit-and-forget” policy describing the connection of distributed generation to the grid without paying attention to power system management and grid constraints. This policy is not critical for the local grid and further stakeholders as long as the share of the connected generators is relatively low. However, if the share increases and the “fit-and-forget” policy is still applied, the system will be hard to manage leading to high costs in the grid for reinforcements. Moreover, inefficiencies occur and increased unreliability is given with the danger of more outages. Scott et al. (2008) analyze that for British grid operators 50% of the distributed generation projected to 2010 can be connected at no additional reinforcement costs. Increasing the share and still applying the “fit-and-forget”-policy leads to non-linear and heavily rising costs of reinforcements since the capacities in the grids are exploited. Hence, the integration of RES-E in distribution grids needs to be performed with innovations and coordination to avoid cost escalating situations.

The increasing (technical) complexity in distribution grids is discussed in Slootweg (2009). According to the study, smart grids are a possible solution to cope with the challenges resulting from more distributed generation by micro-CHPs, PV panels and wind turbines. This may be achieved with improved monitoring and control of grid assets and generators. But how the different market roles (like grid operator, supplier and metering service provider) should cooperate to achieve an improvement and introduce more generation in a smarter way, is not further discussed. In Hamidi et al. (2010) the view of the network operator on the potentials of smart grid technologies is described. The benefits are listed as increasing reliability, flexibility and efficiency. It is stated that the term ‘Smart Grid’ is used as an umbrella for alternative technologies to traditional methods for network operation. Furthermore, a few pilots from various countries (e.g. demand response and storage projects) are described that helped achieving the mentioned benefits. The classification as ‘pilot projects’ of these examples gives a clue to the massive efforts necessary to exploit the smart grid potential.

Next to establishing virtual utilities such as virtual power plants also the development of microgrids is enabled by the Smart Grid vision. The European Technology Plattform Smart Grids defines microgrids as low voltage networks with decentralized generation (such as PV, wind and µ-CHP’s), local storage devices and local, controllable loads (ETP SG (2006)). Although connected to and operating in the distribution grid, these microgrids are able to be transferred in islanded modes if an appropriate coordination of loads, generation and storage is given. This scenario may be relevant in the case of faults in upstream networks and, hence, black-out-situations for the low voltage grid.

There is still only little literature dealing with quantified cost-benefit analyses for the implementation of smart grids. One reason for this is the lack of an established methodology. Further obstacles are the difficulties in evaluating cost and benefits for technologies, applications and solutions and the availability of appropriate data (cf., Giordano et al. (2012)). Finally, a lot of impacts are hard to be evaluated economically (e.g. better voltage quality, better climate, improved customer service, etc.).

One of the first analyses has been published by the Electric Power Research Institute (EPRI), commissioned by the US Department of Energy. An updated study of EPRI with a cost-benefit analysis of the implementation of smart grids in US markets and grids estimates the costs for implementing a far-reaching version of a smart grid up to 476 billion US$ leading to benefits of up to 2,028 billion US$ (EPRI (2011)). Hereby, the costs include the infrastructure for integrating RES-E in distribution grids but not the costs for the generators and the adaptions in the transmission grid for meeting load growth and expansions to connect RES-E. Further examples for costs considered in the study of EPRI are expenses for sensors and other ICT, for the integration of ‘smart’ appliances and consumer devices, for bulk and distributed storage and for cyber security. The benefits are estimated considering enhanced reliability, improved power quality, increased national productivity and enhanced electricity service, among others. Without the implementation of the assumed smart grid components, the full potential of electric vehicles, electricity storage, demand response and RES-E cannot be exploited. As the authors also admit, the estimations are faced with high uncertainties, also caused by the long time period (20 years) considered in the study. Furthermore, the allocation of costs and benefits to the different stakeholders in the supply chain is not considered in the study.

Further studies evaluating the costs and benefits in smart grids are presented by Moslehi and Kumar (2010), Giordano et al. (2012), Blom et al. (2012) and Faruqui et al (2010). According to the latter study, only the costs for installing smart meters in the EU will amount to 51 billion € with operational savings between 26 and 41 billion € (e.g. for reduced thefts and losses and savings in the billing process). Nevertheless, the profitability of a smart-meter roll out is still given due to the opportunity of establishing dynamic pricing. With this paradigm shift, consumers are able to respond immediately to changed prices, e.g. from spot markets, and this may lead to significant reductions of the peak demand. According to the study, the possible decrease in overall costs for expensive peak power plants could outweigh the cost increase for installing the smart meters by far. An investigation of the IEA (2011) shows that peak demand for electricity will increase between 2010 and 2050, but could be reduced by 13% to 24% for the regions considered when exploiting the potentials of an implementation of the smart grid (IEA 2011)). Giordano et al. (2012) present a methodology for evaluating cost and benefits for a smart grid roll out, which is applied on a real case study of a Portuguese smart grid project (InovGrid). However, the study provides no detailed insights in the results and no concrete and quantified cost-benefit-ratios are presented. Blom et al. (2012) show for the Dutch electricity system positive impacts for the society and benefits exceeding the costs for a smart grid roll out. For this, three different scenarios are analyzed with different visions and political strategies with a) business as usual, b) increased usage of renewables and natural gas and c) increased usage of carbon capture and storage (CCS) and nuclear power. The simulations extend to the year 2050 and show highest societal benefits for the smart grid roll out in the case of an increased usage of renewables and natural gas (scenario b)). Nonetheless, also for the both alternative scenarios, benefits outweigh the costs and hence, smart grid roll out seems to be beneficial also for these possible pathways.

As shown in these studies, smart grid roll outs are expected to lead to both high cost and benefits. Hereby, the economic justifications are derived from a societal perspective indicating promising cost-benefit ratios. However, the allocation of costs and benefits to the different stakeholders and market roles in the electricity system has not been considered in detail. As will be shown in the progress of this thesis, the smart grid implementation is not only a question of a promising cost-benefit ratio. The roll out of smart grids is also seen as an obligatory request going along with the transition to a sustainable electricity system. The local demand and - if available - local storage behavior have to follow the (local) generation profiles as good as possible, especially when considering the fluctuation in the feed-ins of

PV and wind generation. Since the transition in this generation part has started successfully in a lot of countries all over the world and the reaction of demand side and the introduction of local storage devices still lags behind, the focus in the next chapter is on the feed-in characteristics of RES-E. Hereby, the generation patterns in a local area (30-kV distribution grid) are investigated. This analysis is required for the further elaborations on storage characteristics and the interaction of stakeholders in the supply chain.

2.4 Conclusion

This chapter provides a background on the economic and technical framework of the electricity system. In the first part, the elaborations focus on the fragmented supply chain with a main differentiation in a natural monopoly and a competitive part. For both worlds, the characteristics are explained, so that typical ways and concepts of regulation as well as main markets for electricity are briefly described.

As a part of the supply chain, the distribution grids play a very important role in the electricity transition. The subsection dealing with the technical issues focus on the main restrictions and challenges given in distribution grids with a growth of (flexible) consumption devices and RES-E. Based on the elaborations, it is illustrated that a copperplate scenario fading out restrictions in the grid (such as voltage and load values) does not appropriately reflect reality and may cause significant reinforcement costs.

Furthermore, suitable definitions for the ‘Smart Grid’ with a presentation of the required steps to introduce such a concept on a wide scale are provided. Current literature discussing the costs and benefits highlight the potential, but also the need for a concretization of technologies and possible market designs to allocate costs and benefits to the different stakeholders.

3 Feed-in characteristics of RES-E and the impact on distribution grids

Abstract: *The integration of electricity generation out of renewable energy resources (RES-E) leads to major challenges for distribution system operators. When the feed-in of photovoltaic (PV), biomass and wind generators exceeds significantly the local consumption, large investments are needed. On the other hand, local generation may reduce grid costs and improve the quality of supply if matched suitable to local demand.*

In this chapter, methodologies are introduced to investigate the feed-in profiles of RES-E generators. To improve the knowledge on the interaction between the technologies, statistical information for load curves, correlation coefficients, frequencies and amounts of peak generation and general feed-in behavior is derived. These derivations are based on measured data of different generators in a German distribution area. The presented results are useful for the dimensioning of grid structures and assets. Furthermore, an approach is presented enabling the calculation of the maximum and minimum feed-in resulting from different combinations of the considered technologies. Finally, a discussion based on the new insights in the feed-in profiles is started to improve the efficiency of RES-E integration.[17]

3.1 Introduction

To deal with the increased amounts of RES-E installations and to adapt the grid assets to future demands, a better knowledge of the feed-in characteristics of the various forms of PV, wind and biomass generation is required. This knowledge enables an appropriate dimensioning of the grid assets and a technical evaluation of innovative alternatives to integrate RES-E. To achieve this, in this chapter measured data of PV, wind and biomass generators are analyzed, situated all locally in one distribution area. For this, data of one particular area (Emsland, Germany) is used, but the presented approach is generally applicable and, thus, can be used also in other regions. This also applies for some of the main results (e.g. correlations, feed-in profiles, peak behavior), since weather conditions are similar in a lot of inland regions, e.g. in Central-Western Europe.

A main question to be answered in this chapter is whether or not the currently assumed maximum for the feed-ins of RES-E technologies based on theoretical calculations exceed measured, ‘real’ values and in case they do, how large this excess power is. This maximum for the feed-in of RES-E is relevant for the grid planning since assets have to be dimensioned for this scenario. In a next step it is investigated, whether the maximum feed-in to be considered for a group of generators is just given as the sum of the maximum

[17] Parts of this section are from [Ny:3].

values of the individual generators or depends on the number of considered generators of a specific technology.

Besides the maximum, also the minimum contribution of RES-E is important for the grid planning since local RES-E contributes to voltage maintenance and reduction of the stress of the grid assets (see Section 2.2), so that these values are determined as well. Furthermore, statistical findings like load duration curves and correlation coefficients are derived. This data forms the basis for the results presented in some of the following chapters and future work on determining and evaluating smarter solutions for the distribution grids (e.g. storage and Demand Side Management (DSM)) compared to conventional alternatives with reinforcements of assets (e.g. bigger or additional cables and transformers). Such smarter solutions may also include an improved interaction of RES-E, e.g. by exploiting the flexibility of biomass generation to balance the fluctuating feed-in of PV and wind. This balancing is seen as an important factor for a sustainable energy system and needed in the context of smart grids (see Section 2.3)). The analysis with real world data enables the evaluation whether or not current (German) RES-E support systems incentivize this interaction of RES-E.[18]

Finally, a tool is presented which allows the calculation of maximum and minimum feed-ins for different portfolios of RES-E generators with different types and sizes of RES-E generators. The presented results are based on the situation in the considered distribution area in Germany (Emsland) and lead to an increase of the knowledge on PV, wind and biomass feed-in characteristics, which allows an improved grid planning with higher shares of RES-E.

The remainder of this chapter is structured as follows. In the next section a brief presentation of related work is given. Section 3.3 gives the mathematical methods used for the statistical investigations, followed by the results of the statistical analysis (Subsection 3.4.1) and the impact on distribution grids including the used tool (Subsection 3.4.2). This chapter ends up with a discussion (Section 3.5) and a conclusion (Section 3.6).

3.2 Related work

The statistical relations of various RES-E technologies and the cooperation of the technologies for local electricity generation have been investigated in several studies. The derived results depend on the underlying geographical and meteorological conditions. Furthermore, the purpose and the objective of the given RES-E generation are important. If RES-E has to supply a remote area and follow consumption patterns, it will differ in the feed-in characteristics from a RES-E plant connected to a fully developed grid, where the RES-E operator will maximize the profit by maximizing the feed-in or by reacting on price signals (e.g. to balance fluctuations of other power generators). In several use cases the generation characteristics of the RES-E technologies are investigated with respect to the ability of being able to supply remote areas autonomously (cf., for instance, Baredar et al. (2009), Beyer and Langer (1996)).

In this context, another relevant aspect is the length of the measurement interval. For example in Baredar et al. (2009) the correlation of wind and PV is calculated with monthly values of their feed-in. However, if the impact of RES-E on grid assets is the subject of the

[18] Note that according to REN21 (2012) similar subsidy schemes compared to the German system have come into force in 57 countries.

research, the time intervals need to be much smaller considering the immediate effect of a changed feed-in on the simultaneously changed grid state. Since for PV and wind the feed-in can change quite fast over a short time-interval, these dynamics need to be considered for an appropriate analysis.

Most of the research has been built on 'synthetic' feed-in data. For this, weather conditions are combined with technical specifications of the generators and based on this data generation patterns are calculated (see, for example Borowy and Salameh (1996) and Kesraoui (2009)). An analysis considering real production patterns of different RES-E technologies over a longer time period (e.g. one year) is missing. Furthermore, most of the current research focuses on the transmission system operator level (Bouhouras, et al. (2008), Lund (2006)). Hereby, a large-scale view is chosen investigating the effect of RES-E integration for complete (regions of) countries. However, the coexistence of PV, wind and biomass may lead in local distribution grids to different effects, since the generators will react simultaneously and highly correlated on changed weather conditions due to the locality. The potential of an interaction of decentralized generation to balance fluctuation of the RES-E production is investigated in Lund (2005a) and Lund (2005b). The studies show a significant decrease in surplus energy by enabling the operation of decentralized combined heat power (μ-CHP) to cope with the fluctuations of wind, based on Danish data.

Hence, the investigation of RES-E using measured values for PV, wind and biomass generators and focusing on a fully developed (existing) distribution grid is a relatively new research topic.

3.3 Methodology

For evaluating the impact of RES-E on the dimensioning of distribution grid assets, the three relevant technologies PV, wind and biomass and their feed-in characteristics in a distribution grid area are analyzed. The used data was measured with 15 minutes interval for one complete year (2010). For determining the results in the calculation tool at the end of this chapter, data for 2011 is included as well to increase the validity and robustness for grid planning purposes. To draw conclusions not only for single generators, but for a complete distribution grid area, ten generators of each technology are chosen. As mentioned in Section 3.1, the basic characteristics like correlations and peak behavior should be similar for a lot of inland regions, e.g. in Central-Western Europe. The focus of the analysis is on a rural distribution grid - the generators are all located in a 30-kV grid (approximately 100 km²) of RWE Deutschland AG in the Emsland, Germany. The selection of the generators is a representative choice of generators connected to the 10 or 30-kV grid with 'typical' sizes of biomass generators (around 400 kW), large PV generators (between 140 and 800 kW) and wind plants ('old' generators with low height and 500 kW as well as larger, 'new' wind parks). The underlying grid situation and a scheme of the locations of the generators within the grid are presented in Appendix A.3.I at the end of this chapter.

For calculating the correlation among the generators of one technology (e.g. between PV1 and PV2, denoting two instances of the PV generators), the 15 minutes values for both generators are considered. The correlation between the different technologies (e.g. between PV and wind) are determined based on the averages for all 15 minutes periods of each specific technology, i.e. the average feed-in profile for PV, wind and biomass, respectively, is used. Note that the correlation coefficients range from -1 (total complementary and

highly anti-correlated) to +1 (total supplementary and highly correlated) and that a correlation coefficient of 0 indicates no statistical correlation at all.
For the further considerations a few more facts are relevant:

- PV generators: the maximum capacity of PV generators can be given in three ways. The module power of the PV panels is characterized as DC power [kWp], whereas the nominal converter power is characterized as AC power [kW_N]. For each PV generator the achieved maximum feed-in for one 15 minutes interval in the year is defined as 100% [kW_{max}] since this is the maximum power 'really' fed in the grid. The given data shows that there is a significant difference between theses power values for all PV generators. The average ratio kWp/kW_{max} for the ten PV generators amounts to 1.17, so the module power is in average about 17% higher than the power 'reaching' the grid due to losses during DC/AC converting or suboptimal dimensioning and orientation of the PV generators. This effect is not visible in the data set of wind and biomass generators, which show a maximum feed-in corresponding precisely with the nominal capacity of the generators. The values of the 15 minute intervals for each PV generator are given as the share on the maximum achieved feed-in [kW_{max}] of the corresponding plant. All PV generators are connected to the 10-kV-level.
- Wind generators: for analyzing the wind generators, a mix of small wind generators and large wind parks is chosen since this represents the prevailing situation in the distribution grid. The large wind parks are not connected within the 10- or 30-kV grid but on the next 110/30-kV substation, so the investigated distribution grid area has to be extended for these generators (see Appendix A.3.I).
- Biomass generators: all biomass generators are connected to the 10-kV-grid. The power generation is performed with a combustion process using the produced biogas from energy crops and agricultural waste products.

Furthermore, it is important to notice that RES-E generators are supported by a guaranteed feed-in tariff (EEG (2011)). Thus, current prices of electricity on spot markets or grid restrictions are of no importance for the plant operators so far. The maximization of profits is achieved by the maximization of feed-in. Hence, feed-in profiles for PV and wind generators are only influenced by meteorological conditions while trying to maximize the harvest of sun and wind. For biomass generators, a maximization of operating hours can be seen as a reasonable objective to cover fixed costs for the investment. According to this, feed-in profiles are expected which show the full exploitation of the potential of the RES-E production on the corresponding locations. Thus, this support by the feed-in tariffs may provide no incentive for flexible generators to react on fluctuations of other power generators (in contrast to the work described in Section 3.2 and presented in detail in Lund (2005b))[19]. The results of the analysis of the feed-in characteristics of the RES-E technologies are given in the next section.

3.4 Results of the analysis

The analysis of the RES-E generators includes all 15 minutes intervals for every generator in the year 2010. As described in Section 3.3, the calculation tool considers data for 2011 as

[19] First adaptions to this support system have come into force recently, e.g. in Germany, but RES-E operators can (up to now) decide whether or not to participate.

well. The (very seldom) intervals with power failures in the grid have to be masked out since no consumption and feed-in is possible during this time. In the given data, this has been the case for a short time period in the summer in 2010 with an electric short cut due to storm damages. In the following subsection, the results of the analysis are presented. Hereby, more than two million measured values are considered. In Subsection 3.4.2 the impact on the distribution grid is presented.

3.4.1 General results of the statistical analysis

After preparing the data as described in Section 3.3, the load duration curves of the generators are calculated to allow a first visual view of the data. In the load duration curve all 15 minutes values of the average of PV, wind and biomass generators, respectively, are sorted descending. Hereby, the hours of a complete year (8,760 hours) are given on the x-axis while the rate of feed-in is calculated as actual feed-in divided by the maximum feed-in. The results are presented in Figure 3-1.

First of all the high availability of the biomass generators is remarkable. Obviously, the optimized plants work under full load except for a short time, which mainly is due to maintenance. Furthermore, the minimum value is interesting. Only in a very short time of the year, the average feed-in falls below 70% with 60.8% as the minimum value in one 15 minutes interval. Also for wind and PV, the maximum and minimum values are of special interest. The curve for wind starts at a higher point than for PV with 94.5% for wind and 89.4 % for PV. This maximum value is lower than 100% due to the asynchronous reach of the peak by the different generators of a technology and results from different locations and orientations of the plants. Although starting at a higher value, the load curve for the average wind generator quickly falls below the PV generator because the feed-in with high rates on feed-in is more seldom. After 3,600 hours, the PV curve passes the 1%-value of feed-in (meaning that no energy is generated in more than half of the year, which is not surprising due to the evening and night hours).

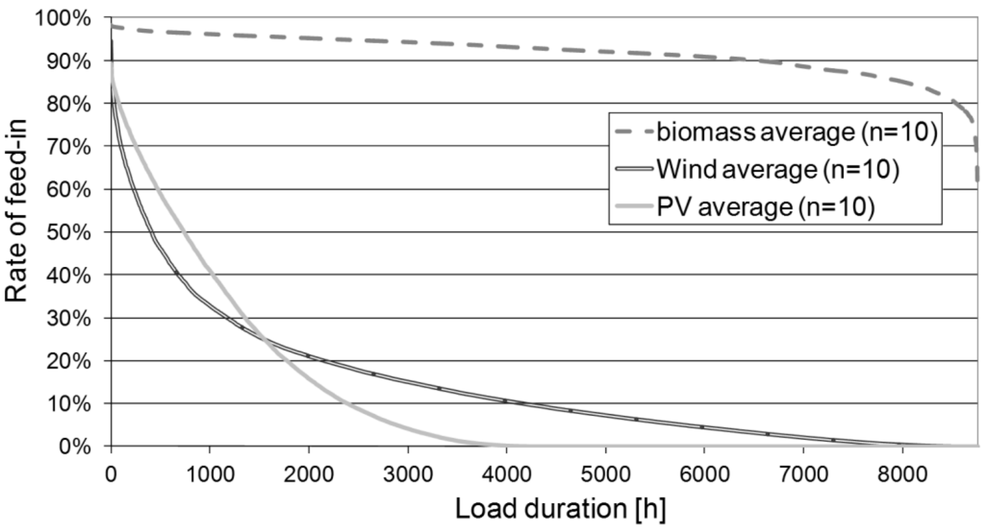


Figure 3-1: Load curves of local generators for one year

To illustrate the feed-in characteristics over the year, the commonly used value 'annual operating hours' is calculated for each generator. This term is defined as the quotient of generated energy [kWh] and maximum possible feed-in [kW]. It expresses how many hours of a year (8,760 hours) the generator has to run at maximum feed-in to produce the annually generated energy by that generator. For the ten biomass generators, this leads to annual operating hours between 7,299 and 8,546 kWh/kW. Compared with the maximum value of 8,760 h, the very high reliability of theses generators is visible since in the maximum case 97.6% of theoretical possible feed-in is reached. However, it also indicates a very static behavior with no response to fluctuating feed-in technologies like PV and wind (see also the discussion in Section 3.5). The calculated operating hours for PV amount to 897 to 1,083 kWh/kW$_{max}$. The amazing large difference is probably caused by (sub-) optimal roof inclination, south-orientation and technical construction of the PV plants. For wind, operating hours of 881 (small generators with low height) to 1,570 kWh/kW (larger wind parks) are calculated. It should be noted that these values indicate that the year 2010 was a weak wind year as the harvest for wind production for German inland generators in 2010 was 23% below the 5-year average harvest (IWR (2011)).

In a next step the correlation between the different RES-E technologies is investigated, since this has an important impact on distribution grids. For this, the correlation coefficients within the technologies and between the different technologies are calculated as described in Section 3.3.

First, the correlation coefficients among the technologies are calculated. As there are 10 generators of each technology, a total of 45 different pairwise correlation coefficients for each technology have to be calculated. For clarification, for example for PV1 and PV2 a correlation coefficient r of $r_{\text{PV1,PV2}}$=0.944 is given. This calculation is denoted as the 'inner' correlation and the results are shown in Figure 3-2a. For each technology, the average value as well as the range of the different correlations is presented. The results in Figure 3-2a show, that the inner correlation for PV generators is the highest followed by the values of the wind generators. The correlations of biomass generators show no statistical relevance. This seems to be logical since the PV and wind generators are faced with similar weather conditions and biomass has no connecting steering mechanism since the maintenance interval can be chosen randomly.

Next, the correlation coefficients between the different technologies are calculated using the average feed-in profiles of the 15 minutes periods. These 'cross' correlation coefficients are presented in Figure 3-2b, where e.g. for the average profile of PV and wind a correlation coefficient of $r_{\text{PV,Wind}}$=-0.066 can be seen. When considering the 'cross' correlations between the technologies, no statistical dependencies for all combinations have been detected since all correlation coefficients for each technology combination are close to zero (slightly negative).

As for more than half of the time periods (the night period) PV definitely cannot contribute to the feed-in, the correlation between wind and PV is recalculated excluding these time periods. When considering only the 15 minutes periods of the month of April until October with 'daylight hours' of 8am to 7pm, the correlation coefficient for PV and wind amounts to -0.040, so there is no pronounced negative or positive correlation visible for this modified time interval as well. To also graphically illustrate the correlations of PV and wind, two point clouds for these two different interval selections (complete year and sun-likely hours) are shown in the Appendix A.3.II.

As mentioned in Section 3.3, a positive correlation indicates supplementary performance, so the peaks in feed-in will intensify each other. Obviously, this fact is given

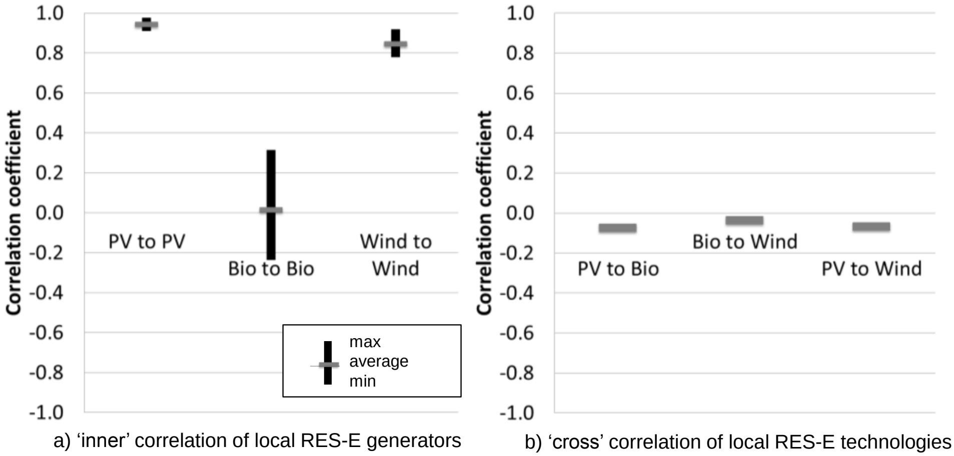


Figure 3-2: Correlation coefficients of local RES-E

for 'inner' correlation of PV and wind. A complementary correlation (negative up to -1) indicating a compensation of the peaks, is not detectable for any of the correlation coefficients. These results give a first impression on the interaction between the RES-E technologies in the considered distribution grid area. The analysis is deepened with the focus on grid-relevant results in the next section.

3.4.2 Impact on distribution grids

This section contains two topics of investigations: in the first part the focus is on the feed-in-characteristics of the RES-E technologies depending on the number of considered generators of one technology followed by an analysis of feed-in characteristics with a mixture of several technologies. The derived results are important for determining the feed-in of RES-E in low- and high-load periods. Nowadays in grid planning the generators are treated independently and, thus, the maximum feed-in of a group of generators can be calculated as being equal to the sum of the individual maximum feed-ins. However, based on the results of Subsection 3.4.1, it may be concluded that this is too pessimistic and that other maximum values may be used. Furthermore, for the high-load periods the minimum contribution of a RES-E portfolio is relevant since this feed-in supports voltage maintenance and reduces load values as mentioned in Section 2.2. Thus, a deeper understanding of the maximum and minimum feed-in values resulting from the different RES-E technologies enables a more realistic grid planning.

The objective of the first part of this section is to find the maximum expected feed-in depending on the number of generators for PV, wind and biomass, respectively. This value gives a meaningful indication on how to consider a group of generators of the same technology within the grid planning when not only one plant but several RES-E generators have to be integrated. To avoid evaluating, for a given number of generators, all possible subsets of that size, the following approach to approximate the maximum expected feed-ins is used. 10 different orders of the 10 generators are randomly generated and for each order the average generation curve for the first k generators, k=1,…,10 is determined. Next, the average of these values over the 10 orders for each value of k is taken. By this, not all subsets of size k, but only 10 are evaluated. This approximation gives a sufficient indication on the relation of maximum feed-in and number of considered generators. The results of the calculations are shown in Figure 3-3.

The results show how the fraction of the maximum feed-in decreases with an increasing number of generators. When considering all of the analyzed 10 generators, a convergence of the rate of maximum feed-in is visible. This effect is particularly pronounced with the PV generators. Using the result of the figure, a direct determination of the maximum feed-in rate relevant for the grid planning is possible. For example, if seven comparable PV generators are connected in one grid area, the value for the planning and calculation does not have to be 100% of the maximum feed-in but can be around 90%. Furthermore, also the ratio of kWp to kW_{max} (see Section 3.3) needs to be considered, so that the actual maximal values for the feed-in is significantly less than the nominal capacity. This effect can have crucial impact on the appropriate dimensioning for reinforcements and avoid an oversizing of grid assets.

Furthermore, to reveal additional important characteristics of the feed-in, the minimum and maximum feed-in values for each RES-E technology within the year are visualized. This range defines the feed-in values occurring for the average RES-E generator. However, not only the whole band is important but also the range adjusted by extreme values of the feed-in. Thus, the complete band is presented (0-100% of time) and an adjusted range fading out the extreme values in the maximum and minimum 1% of the year (1-99% of time, so that only 98% of time is relevant). The results of the calculation are presented in Figure 3-4. The results of the figure lead to the following observations:

- when disregarding the maximum feed-in in 1% of the year, the rate on maximum feed-in is reduced for PV by 9.8 percentage points to 79.5%, for biomass by 0.6 percentage points to 97.6% and for wind by 22.9 percentage points to 71.6%.

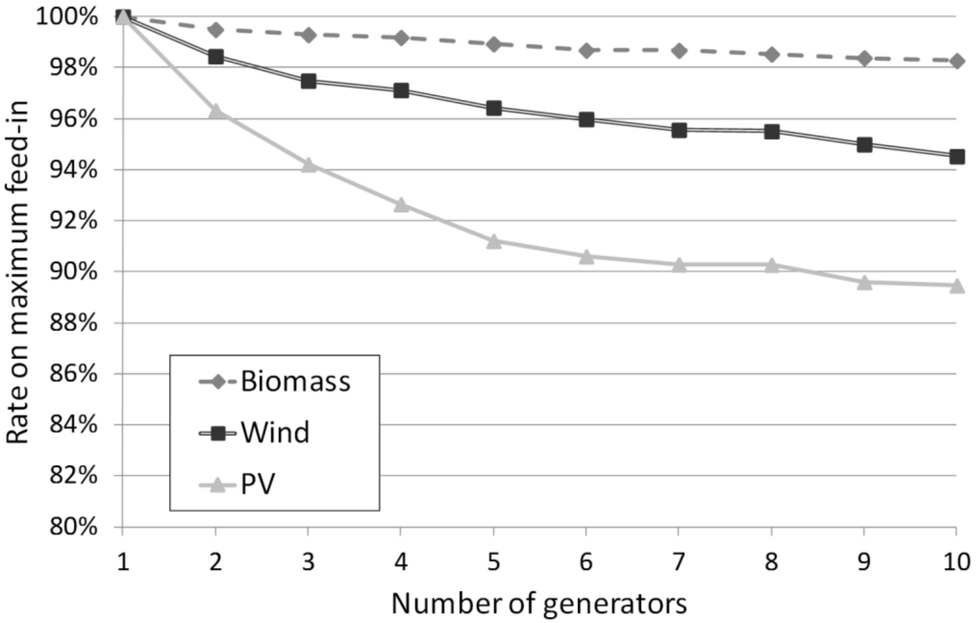


Figure 3-3: Rate of maximum feed-in with increasing number of generators

Thus, especially wind power is characterized by high peaks in a very short period of the year. This effect was already visible in Figure 3-1 to some extent, but here the order of magnitude can be seen in more detail. For the dimensioning of grid assets or the evaluation of Demand Side Management and congestion management, these extreme values are important parameters (see Section 3.5 and Chapter 4). As in certain scenarios a ‘not feeding in’ may be an option, it is also important to know how much energy is produced during the periods corresponding to this 1%-time of the year. More precisely, the amount of energy produced during this 1%-time of the year is calculated which exceeds the production at the 99% value (as only this amount will not be fed in). For biomass due to continuous generation, the energy in these periods is 0.002% of total energy production over the year. For PV, this value is 0.320% and for wind 0.504% of total production.

- when disregarding the minimum feed-in in 1% of the year, the value for the range is unchanged for PV and wind since there are a lot of time intervals with 0% feed-in (see also Figure 3-1). However, for the biomass generators, the rate for the minimum feed-in increases, so in 99% of the year a minimum rate on feed-in of at least 77.0 % is reached. This gives a good indication on the reliability of biomass generators, which is important for the high-load periods (see Section 2.2).

With the given and derived data, a tool can be created enabling the calculation of the maximum and minimum feed-in of different RES-E portfolios. This knowledge on the interaction between the different technologies is useful for the impact in low- and high-load periods (see Section 2.2) when considering a mixture of RES-E technologies. Hereby, for each generator the average of each RES-E technologies with n=10 is considered since Figure 3-3 reveals a sufficient precision when focusing on 10 generators.

After determining the portfolio with the relevant power values for the three RES-E technologies, the tool calculates for every 15 minutes interval the generated power of the different technologies and the sum of all of them to get a value for the chosen portfolio. The

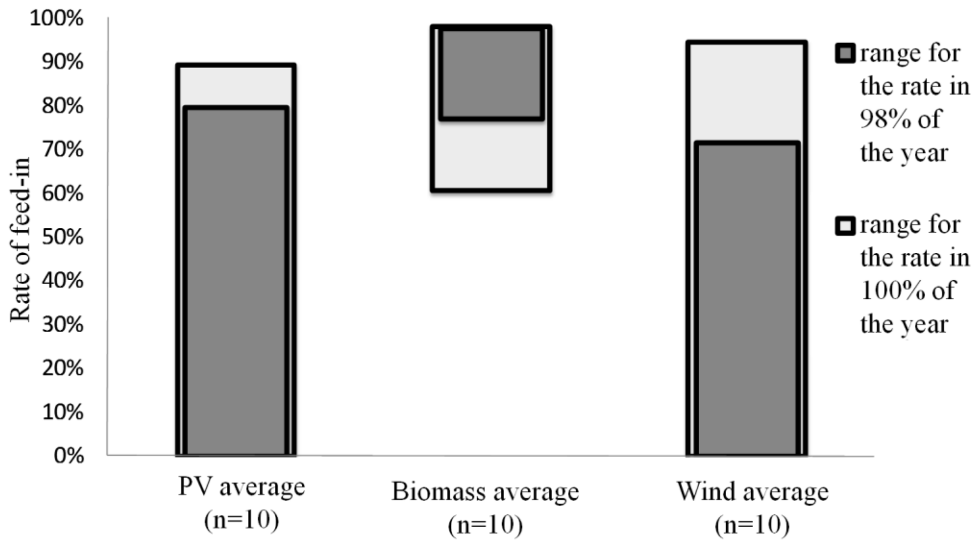


Figure 3-4: Range of feed-in for local generators (n=10) in 98% (fading out the maximum and minimum 1% in time) and 100% of the year

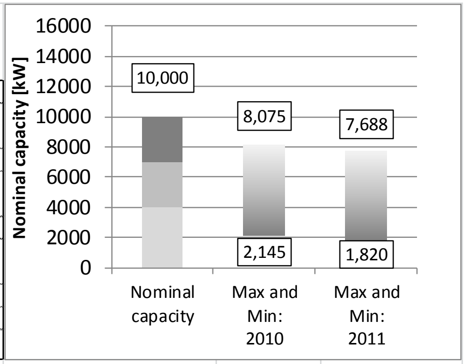
maximum and minimum value is shown, as well as the range for 1-99% of the time and the day when the most extreme values occurred. Moreover, the fading out of the maximum peaks in the 8.7 hours, which have the largest amount of feed-in (corresponding to 0.1% of the time period considered) of a year are calculated. This calculation is also used for the 1 hour a year with the maximum feed-in (corresponding to 0.011% of the time period considered), since both values lead to further insights in the feed-in characteristics of RES-E. In the current version of the tool, the basis for the data is extended with measured values for the year 2011 to increase the robustness of the calculation tool. An overview of the results is visualized for an example portfolio in Figure 3-5.

The results given in the figure are for an arbitrarily chosen RES-E capacity scenario. Again it has to be noted that these results are only valid for the considered region, but give a good indication for other inland regions in Germany and other parts of Central-Western Europe as well. The results for the values measured of the year 2010 show that the maximum feed-in which has to be considered for this scenario is 19.25% below the sum of the capacities of the RES-E technologies (8,075 kW maximum feed-in compared to a capacity of 10,000 kW). This decrease results from the reduced maximum feed-in for the individual technologies with increasing number of generators (n=10) as well as from the mixture of the technologies. When comparing the capacity with the 'maximum -1% in time' scenario a decrease of up to 36.59% is visible. The resulting values for throttling the feed-in in the strongest 0.1% of time (corresponding to 8.7 hours a year) or 0.011% (corresponding to 1 hour a year) further illustrate the peaky behavior of the feed-in portfolios. For 2011 similar results are calculated. Obviously, the tendency to seldom, but high peaks was more pronounced in 2010 than in 2011 since the values for the maximum peak and for the value fading out the strongest hour in the year are higher for 2010 than for 2011. Nevertheless, the robustness of the calculation tool is improved by considering the values of two different years.

Calculation for local generation

with given data set (n≥10 for PV, n≥10 for Biomass and/or n≥10 for Wind)

		kW	
	sum of nominal capacity	4,000	Photovoltaic
	sum of nominal capacity	3,000	Biomass
	sum of nominal capacity	3,000	Wind
Σ	capacity	10,000	sum of all



Results	Results 2010	kW	day of extremum	Results 2011	kW	day of extremum
	Maximum	8,075	24.05.2010 14:00	Maximum	7,688	01.05.2011 12:15
	Minimum	2,145	24.11.2010 16:15	Minimum	1,820	29.06.2011 03:30
	maximum -1% in time	6,241		maximum -1% in time	6,163	
	maximum -0.1% in time	7,174	complies to 8.7 h	maximum -0.1% in time	7,230	complies to 8.7 h
	maximum -0.011% in time	7,977	complies to 1 h	maximum -0.011% in time	7,558	complies to 1 h
	minimum +1% in time	2,569		minimum +1% in time	2,388	

Figure 3-5: Sample result of the calculation tool of occurring RES-E power

The minimum power value is relevant for the high-load period to determine the contribution of local RES-E technologies to stabilize local voltage values. For the presented portfolio, this minimum value is calculated for 2010 with 21.45% of the capacity - this is mainly caused by the continuous biomass generation. The power increases up to 25.69% of the capacity when considering the 'minimum +1% in time'-value. Again, for 2011 similar values are visible.

The tool gives insight into the interaction between the different RES-E technologies and (with underlying weather conditions and based on the measured values for 2010 and 2011) can support the planning of grid structures and dimensioning of assets. As mentioned in Section 2.2, this is particularly relevant for the worst-case scenarios of low- and high-load periods. The results may differ when investigating other generators in other regions, but similar effects are expected since representative generators are chosen. The presented results form a basis for future research and the elaborations in the next chapters, which is further discussed in the next section.

3.5 Discussion

The data and derived results from the previous sections show the importance of the knowledge of feed-in characteristics of RES-E technologies. To verify and consolidate the results, the data of the RES-technologies has to be analyzed annually. The results allow the appropriate dimensioning of grid assets for RES-E for given scenarios. Furthermore, the derived profiles and statistical data allow further research on alternatives to conventional grid reinforcements:

- evaluation of demand side management: the given generation profiles in combination with consumption profiles allow the evaluation of demand side management. For this, appropriate devices like electric cars, electric heat pumps or white goods such as washing machines, can be incorporated in the analysis using an optimization approach or an energy flow simulator. One topic of future research is to integrate the presented analysis within the TRIANA approach (see Bakker (2010a), Bakker (2010b), Molderink et al. (2010), Molderink (2011) and Bakker (2012) as well as the short description of this optimization methodology in Subsection 5.3.2).
- evaluation of congestion management: using the given data, a (welfare economical) analysis is possible which compares the benefit of additional feed-in of RES-E in low-load periods with corresponding reinforcement costs in grid assets for these (seldom occurring) high feed-ins. The analysis is of interest in a larger area with lots of RES-E oversupplying the distribution grid area with energy so that reinforcement in distribution grid assets is needed to transport the energy to other consumption areas.
- improved interaction of RES-E technologies: since current feed-in tariffs provide incentives for a "feed-in as much as possible" mentality, no interaction for the RES-E technologies to compensate for the fluctuating generation patterns is promoted. This approach may be effective to use biomass generation to substitute parts of baseload production of the conventional generation, but with an increased share of fluctuating RES-E generation out of PV and wind, an intelligent steering of biomass seems to be useful. This changed way of operation should lead to a negative correlation coefficient of biomass to PV and wind (complementary

behavior) and a positive value for the inner correlation of biomass (reacting on the same steering signal). Some approaches for an introduction of decentralized generation such as CHP in market designs (e.g. spot and regulation market) are presented in Lund (2006) and Anderson and Lund (2007), but further research to evaluate the potentials, possible ways of steering and appropriate incentives is needed. This requirement is further illustrated by the first adaptions in according laws with fixed feed-in tariffs. Hereby, often optional participation of RES-E investors is offered, so that it can be chosen by oneself, which system is optimal (with respect to the maximization of the profits, not in regard to the most efficient integration in grids and markets. As indicated in this chapter and shown in the practice, current supporting systems lead to a required distinction of these two different perspectives because the maximization of profits for single RES-E investors does not necessarily lead to an efficient integration in grids and markets). The need to improve the interaction of RES-E applies not only for the electricity sector, but also other energy systems such as (natural) gas or liquids should be taken into account. This interaction of energy systems may be promising to convert surplus power to other energy systems in certain time periods with too much RES-E if local DSM potentials with electric vehicles or heat pumps have already been exploited.

- storage dimensioning: to integrate RES-E, also local storage capacities may be a solution in the near future. The appropriate dimensioning of such systems is only possible with the knowledge of prevailing generation and consumption profiles. The data given in this chapter allows simulations in this field. The objective within such an approach may be to store the peaks of PV and wind production in the distribution grid to avoid conventional reinforcements. This research question is the focus of the analysis in Chapter 4.

3.6 Conclusion

To achieve the European climate objectives, electricity generation out of renewable energies sources (RES-E) in distribution grids is seen as an essential element. Distribution system operators and further stakeholders in the supply chain need to improve their knowledge on the interaction between technologies such as photovoltaic (PV), biomass and wind. In this chapter the feed-in of RES-E technologies in a local distribution area is investigated. For this, the feed-in profiles of each 10 PV, biomass and wind generators located in the Emsland, Germany are analyzed. The analysis allows more detailed statements on the feed-in profiles and the impact on distribution grids.

Considering the load duration curves, the high reliability of biomass generators is remarkable with operating hours up to 8,546 h per year (97.6% of the theoretical possible value). Based on the derived maximum feed-ins depending on the number of similar generators it can be compared for instance how the feed-in of 10 PV generators to the feed-in of 10 times the maximum feed-in of single PV generators differs. This calculation leads to a reduction of 11% caused by not simultaneously reaching the maximum feed-in values. An analysis of the correlation between different generation technologies (PV, biomass and wind) shows no statistical significance for correlation. Furthermore, an outlier analysis shows that grid operators have to take in consideration seldom but high peaks for PV and wind generators. For example, when throttling the feed-in of the wind generators in at most

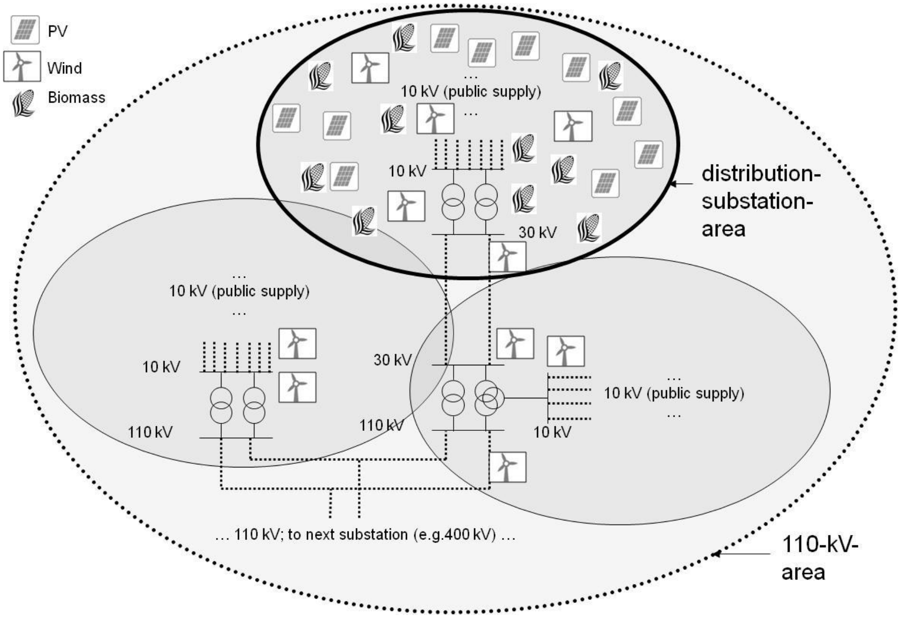
1% of the year, a reduction of the peak from 97.6% to 71.7% of the nominal capacity is visible with a loss of only 0.5% of energy.

The described calculation tool enables the determination of characteristic feed-in values (e.g. maximum and minimum feed-in) of different combinations of PV, wind and biomass capacities. This leads to a detailed description of the interaction between the three RES-E technologies in one distribution grid area, which is useful for a grid operator as well as for plant operators and energy service providers in a future, more ‘smart’ market design.

The presented data and results can form the basis for further work on evaluation the potential of Demand Side Management, congestion management or storage dimensioning (focus of the next chapter) to allow a better integration of RES-E with appropriate and cost-efficient methods. Furthermore, the effective and efficient interaction of these RES-E technologies should be improved with appropriate support systems, especially exploiting the flexibility of biomass generation to balance the fluctuation of PV and wind feed-in.

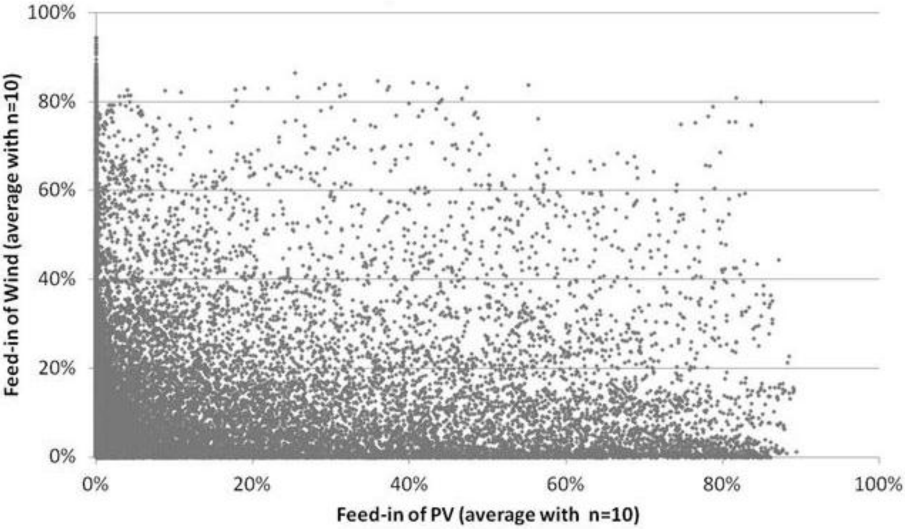
3.7 Appendices of Chapter 3

A.3.I: Scheme of the considered grid area and the locations of generators.

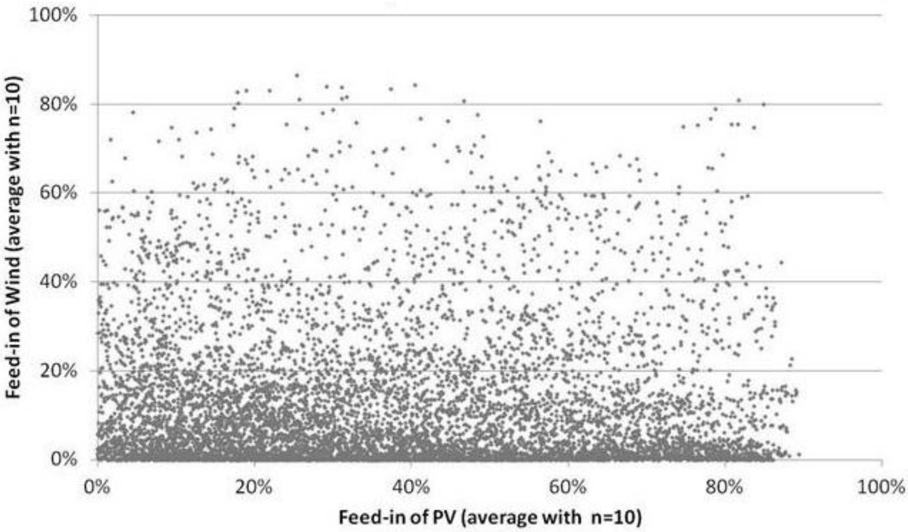


A.3.II: Scheme of the considered grid area and the locations of generators.

a)



b)



a) Correlation PV to wind (year) - pointcloud
b) Correlation PV to wind (April to October, 8am to 7pm) - pointcloud

4 Decentralized storage in distribution grids

Abstract - *The integration of fluctuating power generation based on renewable energy sources in distribution grids and occurring high feed-in peaks requires grid reinforcements. Introducing storage assets can decrease the transported peaks with benefits for the complete technical system. For this, storage technologies need to be chosen and dimensioned according to the prevailing RES-E portfolio.*

In this chapter a model is derived to determine characteristic parameters for storage devices, which are used for peak reductions of photovoltaic and wind generation. For this, the real world data presented in Chapter 3 is used as input. An empirical relation between the peak to be reduced and the required capacity and the number of charging cycles is given enabling a discussion on the choice of appropriate storage technologies. The achieved results show, that the parameters of the storage are influenced not only by the considered type of RES-E technology but also by the number of decentralized generators and the occuring diversity effect.

In a further step, an economical approach is presented enabling the calculation of break-even points for storage systems as a substitute to conventional grid reinforcements. The dynamic profitability calculation considers main influencing cost drivers for both alternatives, including operational and capital expenditures. For this, the calculation of benefits of decentralized storage systems for upstream grid levels is considered as well. These elaborations are reflected on a real world distribution grid faced with reinforcement needs due to the integration of photovoltaic generators. The analyses reveal break-even points for the storage asset, depending on the lifetime of the storage asset and the costs for the alternative (conventional reinforcement). Furthermore, main influencing parameters are evaluated using a sensitivity analysis. It is shown that the profitability can be increased significantly if not all peaks of photovoltaic generation need to be stored. The analysis of the operation for one year indicates that a combined operation of the storage asset (not only oriented on grid objectives such as peak shaving, but considering also the objectives of further stakeholders such as energy traders) seems to be reasonable for increasing the profitability and providing incentives for a larger market penetration of storage assets.[20]

4.1 Introduction

Storage devices are seen as an important element in the future energy supply chain. In addition to a better adjustment of consumption patterns towards power generation patterns, storage assets seem to be needed for a successful integration of fluctuating electricity

[20] Parts of this chapter are from [Ny:6], [Ny:10].

generation out of renewable energy sources (RES-E). Currently, this integration is usually accompanied with conventional reinforcement of the grid, meaning that transmission and distribution system operators invest in additional and bigger dimensioned grid assets (see Section 2.2). These new cables and transformers enable the transportation of the surplus feed-in to other consumption areas. However, this solution still moves electricity over distances, whereas a local storage next to a generator can reduce feed-in peaks by moving electricity over time (Rastler (2010)). Furthermore, also the need for conventional backup power plants might get reduced.

Using storage in this way may reduce the reinforcement needs in distribution and transmission grids, since the assets do not have to be dimensioned for the highest feed-in peaks anymore but for a more flattened generation profile. Thus, storage devices may be helpful for the integration of photovoltaic (PV) and wind generation with their fluctuating generation patterns and seldom, but high feed-in peaks.

In the remainder of this chapter, first an overview of the integration of storage in distribution grids is given. Hereby, the current status with respect to technical and economical perspectives is presented. In Section 4.3 a model for the storage behavior is derived orienting on battery characteristics. The introduction of this model enables the further elaborations in Sections 4.4 and 4.5, whereby the focus is first on the impact of considering different RES-E technologies (PV and wind) and the diversity factor on the storage characteristics. The results enable an appropriate choice of storage assets to be introduced in distribution grids. These results are used in Section 4.5 with an economic analysis of the profitability of storage assets as a substitute to conventional reinforcements. Section 4.6 ends up with conclusions.

4.2 Decentralized storage - status and related work

This section deals with the introduction of storage in distribution grids. In the first part, possible benefits going along with the investments in storage from a distribution system operators' perspective are described. Hereby, the focus is on the technologies and the dimensioning of these assets to avoid grid problems. Further technologies and modes of operation depending on the stakeholder operating the storage assets are briefly discussed. In Subsection 4.2.2, the economic dimension with an overview on current prices is presented.

The installation and operation of storage capacities in the context of this chapter should be understood as the avoidance of grid extension and hence, as an investment of distribution system operators (DSOs). The ownership and operation of storage capacity by the DSO is discussed with respect to the unbundling of market roles. Nevertheless, this investment is considered as one possible smart solution to integrate decentralized RES-E and avoid conventional investment. A deepened discussion focusing on the responsibility of storage operation and ownership is given later in Chapter 5.

4.2.1 Technical dimension

The importance of storage assets as an essential contribution to reach sustainable objectives with increased RES-E is discussed among others in VDE (2008). Next to large-scale technologies (such as pumped hydro power and compressed air storage) also some distributed storage alternatives (such as batteries) are presented. Further overviews on current technologies for storage systems are presented in Barton and Infield (2004), Delille et al. (2009) and Massaud et al. (2010).

One possible way to deal with feed-in peaks is to operate storage devices to flatten the high peaks. This effect with a positive influence on the local voltage values has already been described in Section 2.2 focusing on the general technical challenges in distribution grids. In Droste-Franke et al. (2012) it is stated that storage assets enhance the operation of generators in distribution grids in three ways. First, they can enable a constant and stable output (stabilization). Second, they can bridge the lack of primary energy such as sun and wind. Third, they enable also fluctuating generation types to operate as dispatchable units. These possibilities of the usage of storage assets have a positive impact on the distribution grids since the feed-in peaks can be reduced. Thus, when an investment in storage is economically attractive compared with conventional grid reinforcements, DSOs may be interested to introduce such storage assets. A further important aspect gaining interest is the ability of the storage assets to maintain a functioning grid, even when power faults on higher voltage levels would have led to black outs. In this case of islanded operation, the storage asset and the relevant grid area are decoupled from the main grid, ensuring a local balance of supply and demand, and get reconnected to the main grid after a restoration on the upstream grid levels (cf. for an implemented system in a Dutch distribution grid, de Groot et al. (2013)).[21]

The studies in Droste-Franke et al. (2012) and Farret and Simões (2006) classify the storage assets with regard to the capacity and list further storage features which are important for the appropriate choice, such as energy density, efficiency, self-discharge, recharge rate, lifetime, charge cycles, capital costs and operating costs. As a main characteristic of storage devices, Droste-Franke et al. (2012) defines the *E2P*-ratio [h] as the quotient of the maximum used energy capacity [MWh] and the maximum power of the storage asset [MW]. Later on in Section 4.4, realistic *E2P*-ratios are derived for the storage operation to cope with PV and wind feed-in peaks as well as values for the charging capacity exploited in charging cycle n (denoted as $\Delta E2P_n$) and the number of charging cycles N. Whereas the first value is an indicator for investment costs, the latter can be interpreted as a characteristic for the wearing of the storage asset.

Possible storage technologies for different objectives are described in Rastler (2010)). Hereby, the technologies are classified depending on the system power rating (*SPR*) [MW] and discharge time at rated power (*DT*) [h]. The system power rating is defined as the power of the storage assets for storing and withdrawing of the energy, so that this value indicates the speed of charging and discharging. The discharge time at rated power describes the time required for emptying the storage asset. Based on typical power values in distribution grids, a *SPR* of a few kW up to a few MW depending on the size of the generators is assumed to be appropriate for distribution grid integration with the objective to flatten feed-in peaks of PV and wind generators. The value for *DT* has to be determined based on the RES-E portfolio and is expected to have significant impact on the choice of the storage technologies.

According to the studies mentioned in this subsection, advanced lead-acid batteries, NaS or Li-Ion batteries or flow batteries such as Zn-Air, Zn-Br and Vanadium redox

[21] This scenario of storage for islanded grid operation may not only be beneficial for end-users or areas without (stable) grid connections, but also for the grid operators themselves. This is particularly relevant in quality regulations (e.g. when grid operators are penalized for high outage times and/or have to compensate end-users for values of lost loads (cf. Ajodhia and Hakvoort (2005), van der Welle and van der Zwaan (2007) and the discussion and references described in Section 6.2.2).

batteries seem to be suitable for our application purpose. In Hammerschmidt et al. (2011) an example of a biogas buffer is presented. For this, the biogas produced in a biogas power plant is stored in case of a large contribution of feed-in out of PV generators and withdrawn and combusted to be converted to electricity in case of a lack of PV feed-in. This operation mode enables a flattened common feed-in profile of the biogas and PV generators. The combination of two different types of storage technologies such as lead-acid and super-caps is presented in Lödl et al. (2012). The goal is to exploit the advantages of both technologies reducing the wear and tear and increasing the profitability. The studies mentioned in this subsection provide a first, general overview of appropriate storage technologies for the integration in grids with the focus on avoiding grid reinforcements caused by feed-in peaks of RES-E.

The importance of distributed storage assets for integrating fluctuating RES-E in grids is mentioned in ETP SG (2012) and BDEW (2012) as well. These references state that next to the storage of surplus feed-in at times with low demand, also the power management is of importance. According to the authors, it may be efficient and rational from an economical point of view to curtail seldom, but high feed-in peaks to avoid grid reinforcements.

The use and integration of storage technologies in the electricity supply chain including storage characteristics is modeled and discussed in Barton and Infield (2004), Geth et al (2010) and Lödl et al. (2010)), whereas the latter study focusses on the dimensioning of these assets. In this study, the need for storage as an alternative to conventional reinforcements is described with a focus on the PV technology and the low voltage grid. The storage asset is used in case the PV feed-in exceeds the capacity of the low voltage grid. It is derived that the capacity has to be dimensioned for up to 4 full load hours to cope with the (modeled) PV peak. However, in contrast to the research presented in Section 4.4, the relation of the capacity to the peak power to be stored or the number of charging cycles is not derived. Furthermore, only little transparency with respect to the used data and influences on the results is given.

The research presented in this chapter differs from previous work by deriving empirically the requirements on storage assets based on real world data of PV and wind peaks from a grid operator's perspective. The relation of the peak to be stored to the capacity and the charging cycles is characterized and presented in detail. Moreover, the impact of the difference of PV and wind feed-in behavior as well as the influence of the diversity factor are presented, which to our knowledge has not been done before.

4.2.2 Economic dimension

Since storage is expected to play an important role in future energy systems, there is growing literature on the economics of distributed storage systems and their integration in markets and grids. In Ekren et al. (2009) a break-even point is determined in a case study of an islanded PV/wind/battery-system compared to an extension of the transmission line. The result is that the supply of a decentralized device (in the case under investigation a GSM station) by the islanded system is economically preferred if the grid needs to be extended by more than 4.8 km. However, some main assumptions are not explained in detail and a sensitivity analysis on the influence of the main parameters is missing. The study presented in Lombardi et al. (2012) determines the optimal storage capacity and storage power based on a given RES-E portfolio to achieve certain RES-E shares. The focus in this study is on matching demand and supply by using the storage asset, but grid constraints are not taken into account. In Yi et al. (2012) the influence of Demand Response (e.g. by the control of electric vehicles and heat pumps through signals to shift loads) and the introduction of storage assets in grids is investigated. If one focusses on rural areas, we believe that due to the relatively small amount of connected loads compared to the large amounts of decentralized PV and wind generation, Demand Response may not be sufficient for avoiding feed-in peaks. Hence, no significant reduction of reinforcement needs in such rural areas is enabled (see also the use case presented in Section 4.5). This is even aggravated because of the lack of smart meters, appropriate products and the applied steering mechanism for the required ‘smart’ consumption devices.

A market analysis based on current products on the market for battery systems for end users is presented in Fush (2012). The analysis considers 30 suppliers with 80 products offering a wide range of systems. The lifetimes range from 8 to 25 years and the prices for the investment from 600 to 3,000 € per kWh of installed capacity, whereby the technologies are lead or lithium-ion based batteries. These prices are in line with values of 600 to 800 € per kWh given in bwk (2012). According to a manufacturer’s statement in that article, the goal is to decrease this value to 250 € per kWh in 2020. In Hensley et al. (2012) the prices for battery systems for electric vehicles are assumed to decline to about 200 US$ per kWh by 2020 and to about 160 US$ per kWh by 2025.

A storage asset operated by the DSO may reduce the reinforcement needs also for the transmissions system operator (TSO) when both grids are faced with the same circumstances and profiles of consumption and generation (see Schlegel et al. (2012)). Hence, when evaluating the value of storage for grid operation not only the grid level the storage asset is connected to needs to be considered – also upstream grid levels benefiting from a reduced feed-in peak may be relevant when peak shaving is applied as the optimization objective for the storage usage.

The operation of storage technologies to exploit price spreads is investigated in Ahlert (2010) with an evaluation of the economics of distributed storage systems. Hereby, the break-even points are derived considering the arbitrage perspective. According to the study, the storage capacity is the most important factor for the total storage costs and the investment becomes beneficial for end consumer when hourly flexible electricity prices are available and the costs for the storage assets decrease to 200-400 € per kWh. However, the analysis focusses on exploiting price spreads without considering grid constraints and, thus, has a different research focus. Later on in Section 5.2, it is shown that it is possible to integrate peak reduction also in a scenario where the storage device is installed and operated by an energy trader focusing on gaining market profits by maximizing arbitrage. For this, appropriate mechanisms for the cooperation of traders and grid operators need to be implemented. However, these organizational issues and the potential of a storage usage for traders and suppliers are not the scope of this chapter.

Summarizing, the evaluation of the main influencing factors for the profitability of a storage asset as a substitute for conventional reinforcements is a relatively new research field. Furthermore, the analysis of the storage operation considering measured values of PV generators and real world examples of distribution grids enables new discussions on possible cooperation models of storage stakeholders to improve the profitability and increase market penetration of decentralized storage assets.

To deepen the analysis of these technical and economic issues, a model of a storage asset is derived in the next section. Using this model enables the determination of storage characteristics in Section 4.4 and the evaluation of the profitability of storage as a substitute to conventional reinforcements as presented in Section 4.5.

4.3 Model of a storage asset

In this section a model of a storage asset reflecting typical battery characteristics is presented, because battery systems are seen as promising technologies for distribution grids (see Section 4.2). Considering the RES-E data, the model is applied to determine the main characteristics of the storage dimensioning needed for the economic calculation and the evaluation of the impact of considering different RES-E technologies and the diversity factor.

The operation mode of a storage system is significantly influenced by the objective of the operation. As for the research purpose presented in this section the objective is peak-shaving, a straightforward steering approach can be used. Thus, in these (first) simulations it is not the goal to determine a best possible operation based on knowledge of upcoming profiles (as shown later on in Section 5.2), but to show a straightforward way of operating a storage asset from a grid operators' perspective. This approach has been developed to provide a realistic, but still easy to be implemented, model of the operation of the storage asset for real world usage. Later in this chapter, the straightforward approach is adapted, so that, e.g. depending on the characteristics of the specific storage technologies, the wearing and operational costs of the storage asset can be reduced.

As the input, for each time interval t ($t \in \{1,\dots,T\}$) an energy flow PR_t [kWh] is given denoting the energy generation from RES-E (in the considered cases PV and wind feed-in). The goal is now to influence this electricity flow using the storage. For this, for each time interval t, both an input I_t [kWh] to and an output O_t [kWh] from the storage system is determined. Note that by this always at least one of the two variables I_t or O_t takes the value 0 and that the state of charge SoC_t [kWh] of the storage asset in time interval t can be determined using these variables. To determine this state of charge and the resulting power flow PG_t [kWh] facing the grid in time interval t, an efficiency factor r_{eff} is considered, which is effective during charging and discharging of the storage. Since the value for the efficiency is usually given for one charging cycle (round-trip efficiency), the losses occurring during charging and discharging have to be considered appropriately by being split up over both energy flows. This leads to the following relation of I_t, O_t, PR_t and PG_t:

$$PG_t = PR_t - I_t + O_t \cdot (1 - \frac{1 - r_{eff}}{2}) \qquad (4\text{-}1)$$

This relation (4-1) is also visualized in Figure 4-1. Note that the input I_t in this formula is not corrected by the efficiency factor since this would incorrectly increase the value for PG_t and not consider the losses during charging appropriately. Furthermore, the basic load of the grid is assumed to be static and small compared to the decentralized RES-E in-feed (see also the real world grid situation in the break-even analysis in Section 4.5). If this assumption is not valid for a given scenario, this load may be incorporated into PR_t. The state of charge SoC_t [kWh] of the storage asset is now given by:

$$SoC_t = SoC_{t-1} + I_t \cdot (1 - \frac{1 - r_{eff}}{2}) - O_t \qquad (4\text{-}2)$$

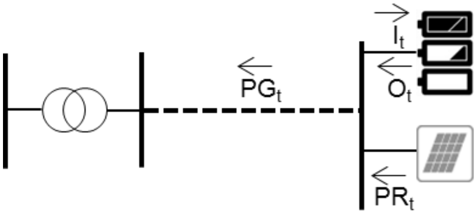


Figure 4-1: Scheme for the energy flows

Note that the losses for charging have to be considered for the state of charge, whereas for discharging they are relevant only for the grid energy flow. Using these formulations, the energy flows can be determined appropriately including the efficiency of the storage with respect to their effect on the state of charge and on the power flow facing the grid. If peak shaving is the objective (as assumed in this research), the storage asset is charged if the permissible power flow PG_t exceeds a predefined bound M [kWh]. Furthermore, the in- and outflow of the storage flows are limited by the charging rate P_I and the discharging rate P_O indicating the maximum power flow to or from the storage in one time interval. This is expressed by equations (4-3) and (4-4).

$$\begin{aligned} I_t &= \min\{PR_t - M, P_I\} && if\ PR_t > M \\ O_t &= \min\{M - PR_t, SoC_{t-1}, P_O\} && if\ PR_t < M, SoC_{t-1} \geq 0 \end{aligned} \qquad \forall\, t \qquad (4\text{-}3)$$

$$PG_t \leq M \qquad \forall\, t \qquad (4\text{-}4)$$

If the production of the PV generator PR_t falls below grid limitations (M), discharging of energy is enabled to empty the storage. A further important parameter for the operation of a storage asset is the depth of discharge DoD, which characterizes the minimal state of charge. This value is often given as a percentage of the installed capacity E_{static} [kWh] and leads to the following lower bound on the SoC:

$$SoC_t \geq (1 - DoD) \cdot E_{static} \qquad \forall\, t \qquad (4\text{-}5)$$

To ensure that also the relation of the (dis-)charging rate to the capacity of the storage assets (denoted as c-rate, see Peterson et al. (2010)), is considered, it is ensured that both, P_I and P_O are bounded by $c \cdot E_{static}$. Hence, a too quick (dis-)charging of the storage asset can be excluded. This constraint is required to consider restrictions of the storage technology and to avoid damage to the assets. The constraints till now describe the operation of the storage. However, as a result, we are mainly interested in the maximum storage capacity E_{static} needed to avoid that the feed-in peaks exceed M. This value is given by the maximum value of the state of charge occurring during the planning horizon:

$$E_{static} = \max(SoC_t) \qquad (4\text{-}6)$$

Note that this value is static and does not consider degradation effects. To determine the real required capacity, a further step to include the effects that capacity reduces over time is introduced. The degradation may depend on the temperature at which the storage asset is operating, the charging and discharging profiles and on the average SoC (see, e.g. Sakuma et al. (2012), Hook et al. (2013)). Furthermore, as Hoppecke (2013) states for a Fiber Nickel Cadmium technology, low temperatures lower the available capacity, while the efficiency of charging is reduced at high temperatures. In Gildemeister (2013) a vanadium redox-flow system is presented by a manufacturer. According to this data sheet, no degradation effects caused by deep or frequent charging will occur. Hence, the influence of the temperature and the storage profiles on the storage lifetime is complex and depends significantly on the chosen storage technology. For reasons of simplicity, a degradation factor d [%] for considering the diminishing capacity per year is introduced. This factor enables the calculation of the capacity required to cope with the feed-in peak at the end of the lifetime of the storage N_s:

$$E_{req} = E_{static} \cdot (1 + d)^{N_s} \tag{4-7}$$

The determined capacity E_{req} is the value, which is used later in the economic analysis to derive the break-even point. Because of the 'peaky' behavior of PV generators and, thus, the short time period between charging and discharging, self-discharging of the storage has not been taken into account.

As well as the technical constraints, also the economic aspects have to be treated (e.g. for the break-even analysis, see Section 4.5). For this, another parameter for the storage operation is introduced: the cost of losses $c_{L,s}$. This parameter depends on the losses L [kWh] and the price p_L per lost unit of energy [€/kWh]:

$$c_{L,s} = p_L \cdot L = p_L \cdot [(\sum_{t=0}^{T} I_t \cdot + \sum_{t=0}^{T} O_t) \cdot (1 - \frac{1 - r_{eff}}{2})] \tag{4-8}$$

Based on the derived model of a storage model it is possible to analyze the main storage characteristics, such as storage capacity depending on the peak to be reduced. For this, in the next section the RES-E technologies PV and wind are investigated on their influence on the storage characteristics. Furthermore, the impact of considering not one, but several generators is analyzed.

4.4 Influence of the RES-E technology and the diversity factor

To be able to evaluate the competiveness and profitability of storage devices as a substitute to conventional reinforcements, first technical parameters for dimensioning these assets have to be determined. The most important parameters are, next to the peak power of the storage asset [MW], the energy capacity [MWh] as cost driving parameters, (and, thus, the ratio of energy to power (*E2P* [h]), see Subsection 4.2.1) as well as the number of charging cycles, which influences the lifetime of the device. Based on these parameters, a choice of an appropriate storage technology can be made.

The dimensioning of storage may depend not only on the RES-technology to be integrated (PV and wind), but also on the number of generators for which the storage asset has to flatten the generation profile. Hereby the asynchronous generation pattern and the diversity factor (quotient of the actual and the installed capacity) play an important role.

Considering these aspects may lead to different values for the storage parameters in different scenarios and, thereby, may have influence on a comparison of decentralized, uncoordinated storage (each generator considered separately) with centralized storage (considering the diversity).

In this section, excerpts from the real world data presented in Chapter 3 are used to estimate the dimension of storage devices in different scenarios. Furthermore, the operation of storage assets is analyzed using a straightforward approach and an improvement is presented to reduce the number of charging cycles. The results give new insights on the requirements of storage assets to integrate RES-E and, thus, enable the development and economic evaluation of such solutions for flattening the profiles of PV and wind generators. The section is organized as follows. In Subsection 4.4.1 the relevant feed-in data is briefly presented. The specific parameters and values, which are only relevant for this part of the analysis, are explained in Subsection 4.4.2 so that in Subsection 4.4.3, the results of a simulation study (considering the model derived in Section 4.3) are presented and discussed.

4.4.1 Measured data

As the used real world data is of importance for the analyses, a short description of this data is given in the following. As explained in Chapter 3, this particular area and the corresponding weather and feed-in data are assumed to be comparable to a lot of other regions and countries due to the inlanded location and the rural character. Since also the influence of the number of generators on the size and operation of a storage device is investigated, an average feed-in profile for both RES-E technologies based on the data of 10 generators is considered as well as the profile of a (randomly chosen) single generator.

For enabling a scalable dimensioning of storage parameters, the measured values of the feed-in are given as shares of the nominal capacity of the generator. The data is given for the year 2011 with 15 minutes intervals. The maximum feed-in of PV considering one (respectively 10) generator(s) amounts to 94.30% (84.62%) of the nominal capacity. Note that in this context the nominal capacity is defined as the nominal power of the DC/AC inverter. Even the maximum feed-in of a single generator is below 100% due to suboptimal orientation of the modules, roof inclination or technical design of the generation unit (PV modules in combination with the inverter). The maximum value for the average profile of 10 generators is significantly lower since the individual PV generators reach their maximum values at different times and, thus, a diversity influence is visible. This effect is also given for wind generators with values of 99.67% for one wind generator and 87.46% for 10 generators. A summary of the given portfolio together with further parameters is given in Table 4-1. It can be seen in the table that the PV generators produce significantly less energy than the wind generators since the average value is lower for PV than for wind (corresponding to a smaller value for the operating hours as described in Chapter 3). Furthermore, the volatility for both types of generators is reduced with an increased number

Table 4-1: Main statistics of analyzed RES-E generators

	PV (n=1)	PV average (n=10)	Wind (n=1)	Wind average (n=10)
average feed-in	11.55%	11.04%	18.53%	17.62%
standard deviation	20.14%	19.07%	20.72%	17.87%
maximum	94.30%	84.62%	99.67%	87.46%

of generators, indicated by the reduced standard deviation of the feed-in values for n=10 compared to n=1.

To provide a deepened insight in the feed-in behavior, which is useful for the further elaborations and interpretation of the data, the measured values of the profiles for a typical period of three days in May 2011 are depicted in Figure 4-2. The figure shows that, as expected, PV feed-in is limited to daytime hours with peaks after noon and the feed-in of wind is spread randomly over the day. Furthermore, the impact of an increased number of generators is visible since the peaks are flattened for the curve of the average profile for PV and wind, respectively. Hence, this diversity effect is likely to have an impact on the storage dimensioning, which is also investigated in the next subsections. The determination of the parameters of storage assets required to cope with the feed-in peaks of the generators is explained in the next section.

4.4.2 Parameters for the analysis

As a further important step, the parameter *E2P* is introduced to describe the relation between the capacity C and the power P (for a detailed definition, see Droste-Franke et al. (2012)). This parameter indicates the time the storage has to operate with the given power P, whereby $P=\max(P_I, P_O)$, to cope with a certain feed-in. As mentioned in Section 4.2, this parameter is very technology specific and cost driving and, thus, relevant for the choice of the appropriate storage technology.

For a given value of M and a specific RES-E technology, the minimal needed power P of the storage asset can be determined quite easily. For this, it just has to be ensured that the storage asset is able to cope with the maximum production value occurring in the time period. This value can be derived from the measured data (see Subsection 4.4.1), but as these are not known on beforehand in real world, P should be determined based on the nominal capacity NC of the given RES-E portfolio:

$$P = NC - M \tag{4-9}$$

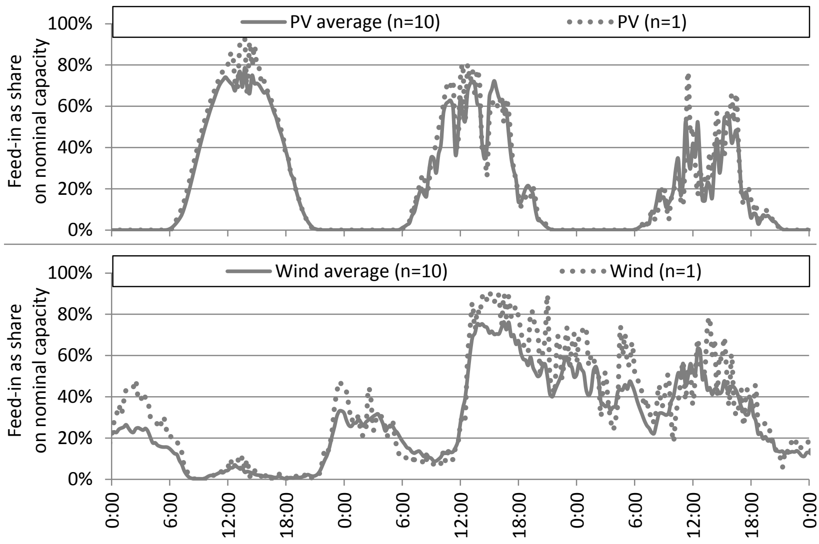


Figure 4-2: Profiles of RES-E technologies of three consecutive days in 05/2011

For the calculation of the $E2P$-values, it is differentiated in two perspectives: on the one hand, via the parameter $E2P_{max}$ the maximum relation occurring in the complete time period is considered:

$$E2P_{max} = \frac{E_{req}}{P} \tag{4-10}$$

On the other hand, also the state of charge within a charging cycle is of interest. Note that this aspect is often not considered in comparable research due to a lack of data or an underestimation of the effect on operational costs. However, different storage technologies require different operation modes and hence, we expect this perspective as an important research field for identifying the appropriate storage technologies for certain RES-E portfolios. For this, it first has to be specified when a charging cycle starts and ends. In this research, it is defined that a charging cycle starts at interval i if an inflow is given (I_t>0) and the last nonzero battery flow before interval i is an outflow (O_t>0). The charging cycle ends at the start of the next cycle.

Furthermore, let $E_{max,n}$ denote the maximum state of charge and $E_{min,n}$ the minimum state of charge of the storage occurring within charging cycle n with n ε {1,…,N} and N as the number of charging cycles. The relation between these different values is illustrated in Figure 4-3 for an ideal storage asset. The ideal storage characteristics indicate

- no losses; r_{eff}=100%,
- no unused capacity; DOD=100%,
- no degradation; d=0%;

These assumptions are used only for the first part of the analysis of the storage operation (Section 4.4) to reveal the influence of the specific RES-E profiles to be stored (wind and PV) and the influence of the diversity factor. Later in Section 4.5, realistic values for the parameters are chosen based on a review on current storage products.

In Figure 4-3 the electricity profiles for three days are depicted. In the basic situation (a), the feed-in of the PV generators exceeds the restricted peak M (illustrated in the figure with 0.6 kWh; hereby, the nominal capacity NC is normalized to 1 kWh and, according to equation (4-9), we get P = 0.4 kWh). This leads to a changed electricity profile facing the grid (PG, see (b)) and a storage flow with an inflow I_t>0 if PR_t>M and an outflow O_t>0 if PR_t<M. Furthermore, the state of charge SoC_t is depicted in picture 4-3 (d). The starting points of the charging cycles are indicated as well as the value for E_{max} and E_{min}.

Using the notations described above, equation (4-11) determines the range of the capacity exploited in relation to the given power within a charging cycle.

$$\Delta E2P_n = \frac{E_{max,n} - E_{min,n}}{P} \tag{4-11}$$

The previously introduced two perspectives are needed since $E2P_{max}$ is understood as an indicator for the investment costs whereas $\Delta E2P_n$ is caused by the operation mode resulting from the chosen RES-E portfolio and the determined value for M. Thus, it seems reasonable that $\Delta E2P_n$ and N as the amount of charging cycles have an impact on the wear and tear and the lifetime of the storage assets (see also the discussion at the end of Subsection 4.4.3).

Using these settings, the impact of the allowed peak M on the capacity values E_{max}, $E_{max,n}$, $E_{min,n}$ and thereby on the factors $E2P_{max}$ and $\Delta E2P_n$ can be derived for the given data.

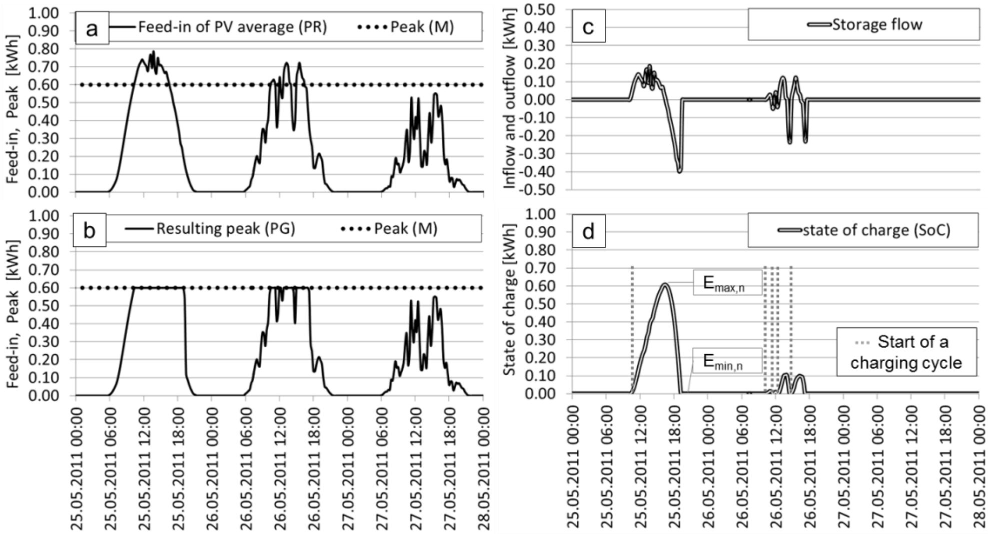


Figure 4-3: Relation of PR_t, M, I_t, O_t and SoC_t

The results for these calculations are presented in the next subsection. Hereby the rather straightforward steering is used with low computational effort applying the battery model (Section 4.3). Furthermore, corresponding frequency distributions for $\Delta E2P_n$ are presented which are based on rounded values to give insight in the minimal and maximal exploitations of the capacity as well as the distribution of the exploitation. Next to this it is shown that with (perfect) knowledge on future profiles one may enable a different operating mode with different values for $\Delta E2P_n$ and N. This is discussed and quantified in the next section as well.

4.4.3 Results

In this subsection the results for the analyzed average and single PV and wind generation are presented. As mentioned in the last section, ideal storage behavior is modeled to enable a focus on the influence of the RES-E technologies and the diversity factor.

The maximum values $E2P_{max}$ are of interest for the design of an appropriate size of the capacity of the storage asset. These values are determined using the model described in Section 4.3 and depicted for different values of the reduction of the peak in Figure 4-4. Note that for wind generation a much larger scale is needed (factor 20). This higher value for $E2P_{max}$ is caused by the higher operating hours of wind generation. Even more important is the enduring feed-in on high levels in seldom situations over longer periods - in contrast, the PV feed-in is always faced to a reduction of 0% of the nominal capacity at night times. In general, the figure provides an indication for the capacity needed to cope with a reduction of the feed-in peak. The results depicted in the figure further show that the difference of the diversity factors is significant as well. The value for $E2P_{max}$ decreases for PV by 9% up to 42% when considering ten instead of one generator depending on the considered reduction of the peak. This reduction amounts to 17% up to 91% for the wind generation. As shown in Figure 4-4, sharp bends are given for high values for the reduction of the peak. These bends occur as soon as the limitation for the feed-in approximates to the average feed-in of the generators.

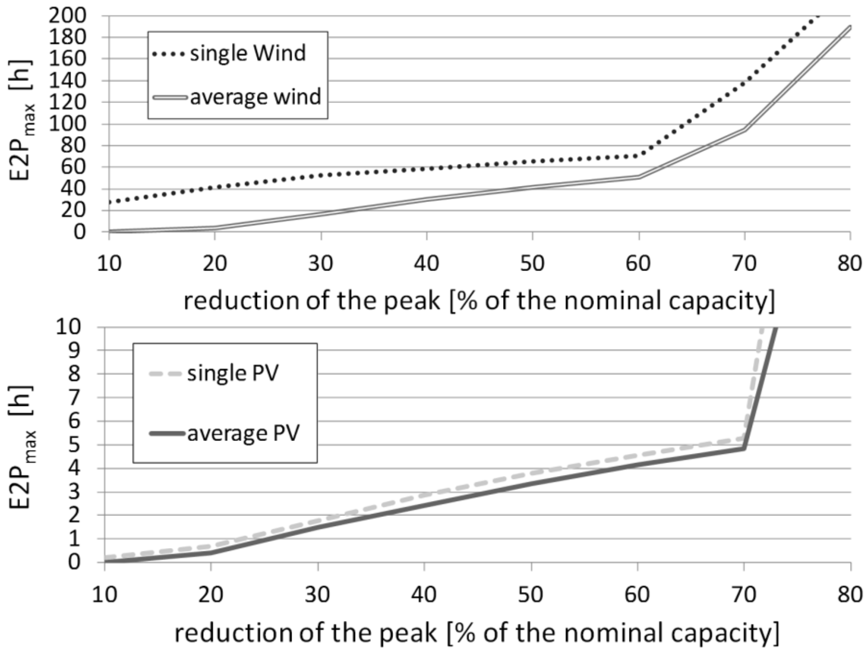


Figure 4-4: Required capacity of storage depending on the reduction of the peak

To illustrate the influence of the diversity factor in more detail, a 100 kW PV generator is considered that is limited to a feed-in of at most 60 kW[22]. For this, a storage with a power of 40 kW is needed and (according to Figure 4-4) a capacity of

- E_{max}= $E2P_{max}$ ·P=2.87h·40kW=114,8kWh
  for a single generator. This capacity may be reduced to
- E_{max}= $E2P_{max}$ ·P =2.44h·40kW=96.6kWh

if the peak of the 100 kW PV results from ten generators.

Focusing on the operation mode, the value $\Delta E2P_n$ is of interest. As an example, in Figure 4-5 the distribution of these values for the charging cycles for the case of a maximal peak of M=60% is depicted, thereby not only giving the maximum $E2P$-value ($E2P_{max}$) but also the frequency for the charging of lower energy amounts. It can be seen that the charging cycles differ significantly when comparing PV and wind since the feed-in of PV can be stored and withdrawn with values of $\Delta E2P_n$ of ≤3 h. The wind profile has $\Delta E2P_n$ values of up to 30 h (average) and 58 h (single). The difference of considering one single generator and the average of 10 generators is not only visible for the maximum values of $E2P_{max}$ but also for the number of charging cycles for all presented ranges of $\Delta E2P_n$. The same tendencies occur for other values of M. Moreover, the figure indicates the needed flexibility of the storage device to cope with the fluctuation of the feed-ins. If no further modifications or constraints are introduced (see the discussion at the end of this section), the storage asset operates very often with low values for $\Delta E2P_n$ (and hence many short charging cycles).

[22] Note that in this example, the power is given as a kW-value after a simple transformation from discrete time intervals to continuous time (kWh/h).

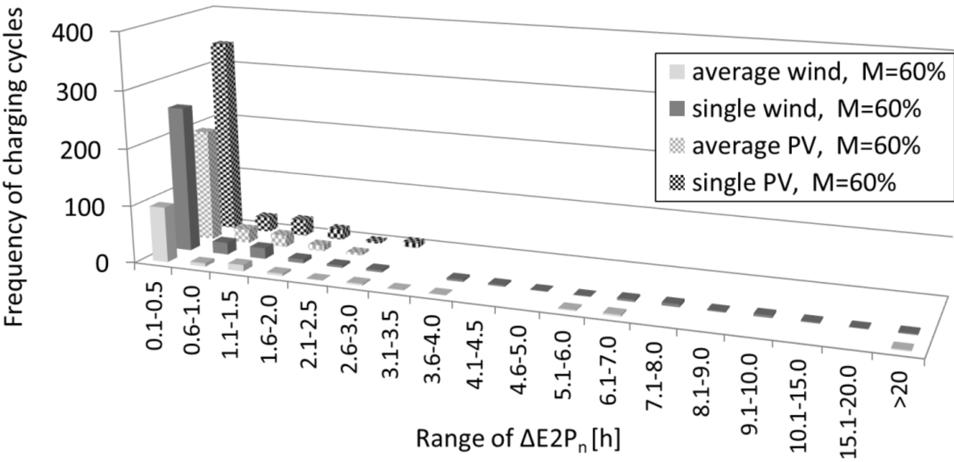


Figure 4-5: Frequency distribution of the charging cycles for *M*=60%

The results presented in this subsection enable the storage stakeholders to narrow down the choice of appropriate storage technologies. If, for example, a wind peak needs to be avoided, long-term storage is needed. The PV profile affords medium-term oriented storage, e.g. in the range of 3 hours for a reduction of the feed-in by 40% of the nominal capacity. Due to their more short-term orientated operation, currently available Li-Ion focusing on discharge times of minutes instead of hours (Rastler (2010)) seems to be appropriate only for low reductions of the PV generation. On beforehand, we had already expected that PV is much easier to be stored compared with wind generation. However, based on the precisely determined values in this section using real world data (in contrast to most of the results and assumptions in literature) it can be stated that the difference is even larger than expected. Thus, wind generation requires completely different storage technologies (i.e. with a larger capacity such as redox-flow batteries or with larger capacities and power, e.g. with hydrogen storage or pumped hydro). The achieved results as depicted in Figure 4-4 can be used to specify storage parameters. This may lead to reconsidering results from literature; e.g. the assumed duration of 5-10 hours for off peak storage of wind or the duration for PV storage beginning with 15 minutes mentioned in (Rastler (2010)) seems to be too small. An important aspect of the results of Figure 4-5 is that a realistic operation leads to more charging with a small range of the capacity and not with a full range. The current implementation of the storage using the straightforward steering approach leads to low values for $\Delta E2P$ and high numbers of charging cycles, since just the minimum required battery capacity to cope with the RES-E peaks is determined and no intelligence in the way of operating the storage is considered. However, another way of steering may be possible to reduce the number of charging cycles and thereby leading to higher values for $\Delta E2P_n$. To provide first impressions on some future research in this context, the minimum number of charging cycles is determined using a mathematical optimization algorithm which takes into account the minimum capacity determined with the straightforward approach. For this, the production profile for the complete year is assumed to be known in advance. In practice, this approach may be realized approximately using prediction, planning and real-time control (see, e.g. the methodology TRIANA presented in Molderink et al. (2010) and described shortly in Subsection 5.3.2). The achieved results for

Table 4-2: Charging cycle for different steering approaches per year

	approach: straightforward storing		approach: minimization of the number of charging cycles		$E2P_{max}$
	number of charging cycles per year	average $\Delta E2P_n$	number of charging cycles per year	average $\Delta E2P_n$	
Average PV, M=60%	254	0.39	41	1.96	2.44
Average Wind, M=60%	129	1.12	6	10.58	30.55

the minimum number of charging cycles N and the average of the range for $\Delta E2P_n$ are given in Table 4-2.

This different operation mode can reduce or increase the wearing - this depends on the chosen technology (e.g. for lead-acid, a regularly full charge and avoidance of deep discharge is preferable, see Bopp and Kaiser (1999)). Nevertheless, the results in Table 4-2 indicate the potential of different steering approaches on the operation mode and thus, potentially on the lifetime of the assets. The approach of minimizing the number of charging cycles enables the conversion of frequent but low charging to (approximately) full charging cycles.

The derived difference for the capacity to be installed when considering the diversity factor may lead to a discussion on the efficient scale and operation of storage. Obviously, a coordinated or centralized storage usage may be advantageous, if no other grid constraints are given. These considerations have to be reflected on real grid situations including additional given constraints such as power, size, location or noise. As a further next step, the storage characteristics (e.g. efficiency) should be incorporated for specific technologies in the presented approach to achieve a more realistic design of the storage dimensioning. With this, the profitability of storage technologies compared with conventional reinforcements can be evaluated. All these deliberations are considered in the next section. Hereby, a realistic storage behavior for peak shaving of PV feed-in is modeled (since for peak shaving of wind power, there are significantly higher costs, as shown in this section). Using the model enables the calculations of break-even points for battery systems as a substitute to conventional reinforcements.

4.5 Profitability of storage for peak shaving of PV generators

In this section, a method is derived to calculate break-even points for decentralized storage assets to be installed in distribution grids. The economic approach considers the main cost-drivers for the conventional reinforcement as well as the most important influencing parameters for the storage asset. As the storage asset may also have benefits for upstream grid levels by reducing the feed-in peak of decentralized PV and/or wind generation, these benefits are also considered. To concretize the results and increase the meaningfulness of the research, a real world situation is presented, which focuses on a low voltage level where reinforcement needs are caused by the integration of PV generators.

Next to the break-even analysis, also the concrete time periods, when the storage asset is used to reduce the feed-in peaks are investigated. This leads to the identification of time periods, where the storage may be used for other purposes (e.g. arbitrage using spotmarket price spreads) because no grid constraints are given (e.g. because of to the lack of feed-in of

RES-E). Based on this, the future role of storage assets in grids, also with respect to the responsibility of different stakeholders, is discussed.

The remainder of this section is structured as follows. Subsection 4.5.1 contains the derivation of break-even points considering different cost types for two scenarios for solving local grid challenges: storage assets or conventional reinforcements. In Subsection 4.5.2 a traffic light system for the storage operation is introduced. This methodology enables the classification of uncritical and critical situations in the grid. An example for a real world grid situation and the results of the break-even analysis as well as the evaluation of the battery operation are presented in Subsection 4.5.3. The last part of this section (Subsection 4.5.4) provides a discussion and impacts of the results and some ideas for future work.

4.5.1 Methodology for the break-even analysis

The objective of the investigation presented in this subsection is to derive the break-even points of investments in storage asset as a substitute to conventional reinforcements. Based on this, the main parameters influencing the profitability can be identified and evaluated. The break-even point is calculated as an €-value per kWh of installed capacity and represents the value at which a grid operator is indifferent between investing in the conventional reinforcement or in the storage asset. Note that in a lot of countries with liberalized energy market it is still under discussion whether grid operators are allowed to operate storage assets in future grids or not. Since we assume this storage asset is primarily introduced to avoid conventional reinforcements, the purpose of the assets is grid oriented and, thus, part of the grid assets. Nevertheless, it may be the case in future market designs that the 'flexibility' introduced for peak shaving using a storage asset is part of a third-party offer and can be purchased by the grid operator. This scenario is discussed later, but does not affect the evaluation of the profitability for grid objectives as derived in this section.

To consider the value of the cash-flows over time, a dynamic approach for the break-even analysis is required (cf., for example, Guang-bin and Bin-li (2007)). The dynamic approach is reflecting the concept of the time value of money, which considers the preference of a present value of money compared with the same amount of money in the future. Hence, this concept takes the interest and the lifetime of an investment into account (see more details in Grant (1938) and Stuebs (2011)) and for an historical overview (Kopf (1927) and Tipping (2006)).

In this analysis the annual costs for maintenance and losses (operational expenditures) c_{OPEX} is used as well as annual capital expenditures c_{CAPEX}. The latter costs are derived from the initial investments costs and consider the interest and the depreciation of the investment spread over the lifetime with a constant, annual value in form of an annuity a (for more detailed on the influence of CAPEX and OPEX on grid investments and costs developments, see e.g. Asgarieh et al. (2009); an overview on the consideration of these costs types in regulation approaches is provided in Jamasb and Pollitt (2000) and Giannakis et al. (2005)).

The different cost types are derived for both scenarios (storage s and conventional reinforcement cr) and the break-even point results from the situation where both scenarios have equal costs.[23]

[23] A list of all used notations is given in Appendix A.4.I at the end of this chapter.

$$C_{OPEX,s} + a_s = C_{OPEX,cr} + a_{cr} \quad (4\text{-}12)$$

Equation (4-12) is the starting point for a detailed investigation to derive the break-even point [€ per kWh of installed storage capacity] and to reveal the main influential factors. For this, in the next subsection first the CAPEX is considered in form of the annuity a, followed by derivations for the OPEX in Subsection 4.5.1.2. By integrating the derived equations, finally the equation for the break-even point can be determined in Subsection 4.5.1.3.

4.5.1.1 Annual costs for the investment (CAPEX)

The annual costs of investments consider the interest and the depreciation of the asset over its lifetime and are determined as an annuity a using the capital recovery factor *CRF*. This term was introduced by Grant (1938) and is widely disseminated and used in practice (cf., e.g. Lynd et al. (1996), Kodal et al. (2000) and Hazeltine and Bull (2003)). The annuity enables the calculation of the profitability of investments with different initial costs (investments) and operational (annual) costs as well as different lifetimes or interest rates. The annuity can be calculated by equation (4-13) whereby *CRF* is given by equation (4-14), I_0 denotes the investment in year 0 [€], i is the interest rate [% per year] and N denotes the lifetime of the investment [number of years].

$$a = I_0 \cdot CRF(i, N) \quad (4\text{-}13)$$

with

$$CRF(i, N) = \frac{i(1+i)^N}{(1+i)^N - 1} \quad (4\text{-}14)$$

In the equations (4-13) and (4-14) the values for i and N are given by the case considered. The only value to be determined is I_0. For the storage asset, this value $I_{0,s}$ is simply the investment needed to get the storage operable. For the conventional reinforcement, $I_{0,cr}$ may be influenced not only by the directly relevant grid area, but may also be affected by upstream grid levels (see elaborations in Section 2.2). Although the transmission capabilities increase with higher voltage levels, an increased number of generators installed in the upstream grid area may also lead to problems in these higher voltage levels and, therefore, may have to be considered too. Thus, decentralized storage strongly influences the operation in the local voltage levels (e.g. if a PV generator is connected to a low voltage level, as depicted in Figure 4-6) but may also reduce reinforcement needs in upstream voltage levels if the corresponding areas are faced with similar consumption and generation patterns (as it is typically the case).

As described above, the economic benefit of local storage operation for the grid may be a sum of the benefits for several voltage levels. Hereby, the transformers between the voltage levels (e.g. from medium to low voltage (MV/LV) as well as the grid levels itself (e.g. low voltage cables and lines) need to be considered. The influence of a local storage on a reduction of the reinforcements in the grid levels tends to be larger in low voltage levels compared with high voltage levels due to a lower transmission capability and, thus, a higher impact of the storage operation. Because of this, the upstream grid levels above the high to medium voltage transformer HV/MV are not considered in our analysis. Moreover,

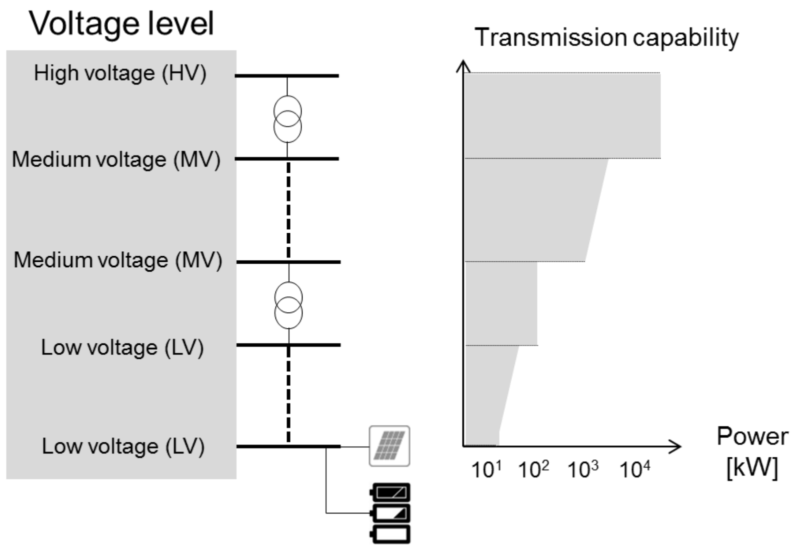


Figure 4-6: Scheme of voltage levels and transmission capabilities

the probability of similar reinforcement needs in larger grid areas as supplied by HV and above (ultra high voltage grid levels) tends to decrease due to a better mixing of consumption and generation areas (e.g. cities and rural areas).

In this approach the contribution to a reduced reinforcement need in different voltage levels is considered by coefficients in the derivation of the investment for the conventional reinforcement $I_{0,cr}$ as shown in equation (4-15). Hereby, the coefficients α, β, γ and δ denote the contribution of the storage asset to a reduced peak compared to the critical peak for each voltage level and I denotes the investment in that voltage level to remove the bottleneck (this is illustrated in more detail in the real world case in Subsection 4.5.3).

$$I_{0,cr} = \alpha \cdot I_{LV} + \beta \cdot I_{\frac{MV}{LV}} + \gamma \cdot I_{MV} + \delta \cdot I_{\frac{HV}{MV}} \tag{4-15}$$

The coefficients as well as the investment values of the reinforcements in the different voltage levels have to be determined individually and are dependent on the prevailing situation in the grid. Note that within a voltage level (e.g. LV) the requirements for reinforcements may depend on the location of the generator. If this generator is connected close to the transformer to the next voltage level (e.g. MV/LV) the voltage increase is not as pronounced as when the generator is connected at a long distance from the next transformer. This effect is considered qualitatively in the scheme in Figure 4-6 with transmission capabilities depending on the distance to the next transformer. Furthermore and as mentioned in Subsection 2.2.2, other innovative alternatives to conventional reinforcements such as voltage regulation appliances may solve the problem locally (e.g. in the LV grid area), but do not reduce the reinforcement needs in other voltage levels since the actual power flow is not affected. Hence, to describe appropriately the benefit of decentralized storage asset on grids, an equation of the form (4-15) seems to be appropriate.

The previous elaborations point out the importance of individual grid constraints as they are determined by the number, size and location of connected RES-E as well as by the size, type and characteristic of directly and upstream connected grid assets. Nonetheless, the derived approach for the CAPEX calculations enables an evaluation of a lot of different grid situations as illustrated in the example given in Subsection 4.5.3.

4.5.1.2 Operational expenditures (OPEX)

The operational expenditures (OPEX) are costs occurring regularly, e.g. for maintenance and losses. In practice, OPEX can be considered in different ways. To create a flexible model for the calculation of the break-even point, two components to reflect these different views are combined.

First, the maintenance part c_M of OPEX is determined in a simple way by determining c_M as a fraction of the investment costs. For this, a ratio f is introduced to calculate the annual maintenance costs. This simplification reflects situations where a dependency between OPEX and CAPEX is detectable and is used often in practice (see, e.g. Claussen et al. (2007) and Verbrugge et al. (2006)). This assumption leads to the following equation for the annual maintenance costs:

$$c_M = f \cdot I_0 \tag{4-16}$$

Such a situation may occur if a cable in the ground has to be repaired. In a high-quality surface (such as tarred ground) digging the ditch for the installation of the cable (investment) is more expensive than for a low-quality surface (e.g. green field), but this relation applies as well for the maintenance costs in case of power failures.

As a second component of OPEX the direct determination of the costs c_L per year is chosen. These costs do not depend on the initial investment. Such costs are e.g. the losses of a storage asset $c_{L,s}$. Summarizing, the OPEX in the model is given by:

$$c_{OPEX} = c_M + c_L = f \cdot I_0 + c_L \tag{4-17}$$

The losses occuring as a result of the power flows for the considered scenarios can be determined by an evaluation of the energy flows with conventional reinforcements and/or the introduction of the storage asset. For this, the storage model derived in Section 4.3 with the equation for the losses (equation (4-8)) is used and reflected to the real world situation in Subsection 4.5.3.

4.5.1.3 Combining OPEX-CAPEX

As mentioned earlier in this section, the objective of the economic calculation is to derive the break-even point of the capacity costs [€ per kWh of installed capacity]. This break-even point is given in €/kWh since the capacity is one of the main cost drivers for the investment (also in literature the costs are given in this unit, see Subsection 4.2.2). Integrating equation (4-13) - (4-17) for both scenarios (storage s and conventional reinforcement cr) in equation (4-12) leads to the following equation for the investment $I_{0,s}$ for the storage (see Appendix A.4.II for the complete derivation):

$$I_{0,s} = \frac{\left(\alpha \cdot I_{LV} + \beta \cdot I_{\frac{MV}{LV}} + \gamma \cdot I_{MV} + \delta \cdot I_{\frac{HV}{MV}}\right) \cdot \left(f_{cr} + \frac{i_{cr}(1+i)^{N_{cr}}}{(1+i_{cr})^{N_{cr}} - 1}\right) + c_{L,cr} - c_{L,s}}{f_s + \frac{i_s(1+i)^{N_s}}{(1+i_s)^{N_s} - 1}} \tag{4-18}$$

The break-even point *BEP* can now be derived by dividing the investment $I_{0,s}$ by the required storage capacity denoted as E_{req} [kWh]:

$$BEP = \frac{I_{0,s}}{E_{req}} \tag{4-19}$$

To determine the break-even point for certain scenarios, it remains to specify some main characteristics of the storage asset, such as the required capacity E_{req} and the costs for losses $c_{L,s}$. These values can be calculated using the model described in Section 4.3. Based on the general results derived in this section, the break-even analysis for the storage asset can be adapted to specific use cases. This applies for individual grid situations as well as to individual storage technologies and PV generation patterns. A concrete real world example for these calculations is given in the Subsection 4.5.3 leading to break-even costs for a storage asset. As a next step, the traffic light system is introduced. This approach enables us to not only derive the storage characteristics based on the objective of peak shaving but to show also the remaining flexibility for the storage operation for other purposes.

4.5.2 Flexibility of storage operation - the traffic light system

In the context described previously, the storage asset is used as a grid component. However, it may be of interest, to determine how much flexibility for other purposes (arbitrage at day ahead or intraday markets or ancillary services with fast responses in the regulation market) is left. The German Regulation Agency (BNetzA, 2011) and BDEW (2013) propose a traffic light system with green, orange and red periods, whereby the general concept is still relatively vague and needs to be developed more precisely. Hence and to get appropriate and meaningful indicators for a specific realistic example, the time periods are clustered in this work also according to a traffic light system with:

- s_{red}: fraction of time periods with no flexibility for other storage objectives. In these time periods the storage asset is either needed to ensure the grid operation without exceeding grid limitations, $PR_t \geq M$ (see equation (4-20)), or the storage is filled completely and further storing is only possible with an increase of the determined capacity, which should be avoided due to negative impacts on the profitability.

$$s_{red} = \frac{\sum \mu_{red}}{T}$$
$$with\ \mu_{red} = \begin{cases} 1\ if\ PR_t \geq M, \\ 1\ if\ SoC_t = E_{static}, \\ 0\ otherwise \end{cases} \tag{4-20}$$

- s_{orange}: fraction of time periods where ‘some’ flexibility is left; i.e. $0 < PR_t < M$. Note that in these time periods, there is still the risk that the power flow facing the grid exceeds its limit, see equation (4-4). If in these time periods the storage assets is used also for other purposes (except grid objectives), a cooperation of the stakeholders is required to avoid undesired and invalid grid situations (see also the case in Subsection 4.5.3 and the further analysis on the interaction of stakeholders in Section 5.2). Furthermore, the orange traffic light phase is characterized by the risk of exceeding the storage capacity in time interval t based on the state of charge SoC_{t-1} and the maximum charging rate P_I, which should be avoided as well.

$$s_{orange} = \frac{\sum \mu_{orange}}{T}$$
$$with\ \mu_{orange} = \begin{cases} 1\ if\ 0 < PR_t < M, \\ 1\ if\ SoC_{t-1} > E_{static} - P_I \cdot \left(1 - \frac{1 - r_{eff}}{2}\right), \\ 0\ otherwise \end{cases} \tag{4-21}$$

- s_{green}: fraction of time periods with a maximum flexibility left; i.e. $PR_t = 0$. Still, equation (4-4) has to be fulfilled, but since the PV generator produces no electricity, the room for feed-in is left completely to the storage operation. Note that the state of charge should not exceed the capacity of the storage asset in these time intervals.

$$s_{green} = \frac{\sum \mu_{green}}{T}$$
$$with\ \mu_{green} = \begin{cases} 1\ if PR_t = 0\ and \\ \quad if\ SoC_{t-1} \leq E_{static} - P_I \cdot \left(1 - \frac{1 - r_{eff}}{2}\right), \\ 0\ otherwise \end{cases} \tag{4-22}$$

The classification of time intervals in these traffic-light-periods is used later on in Subsection 4.5.3.4 to illustrate the exploitation of the storage flexibility for the grid oriented operation which enables the discussion on further operation modes considering multiple objectives.

4.5.3 Real world situation in a distribution grid

In this subsection an example is presented which reflects a real world situation in a German distribution grid. It has been chosen because it also reveals the complexity in distribution grids and the individuality of specific grid situations for calculating the impact of storage assets in these grid scenarios. As electrification of households has been realized in a lot of countries in a similar way and with comparable resulting grid situations, the scenario is likely to occur also in other regions and countries with growing PV penetration.

The particular situation of the real world case is explained in more detail in the next subsection. The values for the parameters needed to calculate the break-even point are set based on practical experiences and given in Subsection 4.5.3.2. The results of the analysis considering the main influential factors are presented in Subsection 4.5.3.3. In addition to this, also for the other parameters a sensitivity analysis is provided to reveal their impact on the break-even point.

4.5.3.1 Situation in the real world distribution grid

In the chosen real world situation, the reinforcement need is caused by two PV generators located at two neighboring farms, which are connected to the same low voltage level. The electricity load of each farm is modeled with 5 kVA, resulting from a low consumption period (e.g. at a Sunday at noon). As explained in Section 2.2 and according to the described feed-in surplus, the connection of two PV generators with 30 kVA[24] each leads to a voltage increase. This voltage effect is usually the limiting factor and hence, causing a reinforcement in the grid. The length of the low voltage cable from the farms to the 10-/0.4-kV-transformer is given with *L*=750 m. The low voltage level is operated with 400 V phase-to-phase voltage and a frequency of 50 Hz. The cable is a standard used grid asset (4x150 NAYY-J se) with a resistance *R*'=0.202 Ω/km and a reactance *X*'=0.078 Ω/km. Note that these values depend on the installed grid assets and hence, may differ when considering another distribution grid. Furthermore, the situation in other grids will differ in detail (e.g. the values for generation and consumption as well as the length of the cable *L*), but the challenges occuring in this rural area and the problems of the increased voltage values are comparable to a lot of other grid scenarios. A scheme of the grid situation is depicted in Figure 4-7 and a snapshot of the geographical plan is provided in Appendix A.4.III.

As described in Section 2.2, the grid operator is forced to enable an operation of all devices connected to the grid within a voltage range predetermined in the European Norm EN 50160. Hereby, the voltage increase has to be limited to 10% of the nominal voltage U_N. There exist programs and simulation tools to consider all relevant grid levels up to the next constant voltage value (called the slack node, e.g. the 110/10-kV-transformer) and to evaluate the consequences of changes in the grid. For sake of transparency, for this example a simplified approach is used to determine the voltage increase due to the operation of RES-E in the grid level where the RES-E is connected to. Hereby, the voltage increase within the considered voltage level occurring when RES-E is operating is restricted to e.g. 3% compared to an operation without RES-E (see VDE-AR-N 4105 (2011), §5.3 for the low voltage level). In the chosen grid scenario, the calculation using appropriate power system simulation tools shows a voltage increase of 3% when connecting one of the PV generators to the grid. If both generators are installed, a second cable is needed (*L*=750 m) to increase the short-circuit power at the connection point and to enable a permissible operation with a voltage rise of at most 3%. Note that because the load of the cables is restricted to 150 kVA each, the current carrying capacity (ampacity) is no problem in the considered situation with respect to the stress of the low voltage cables.

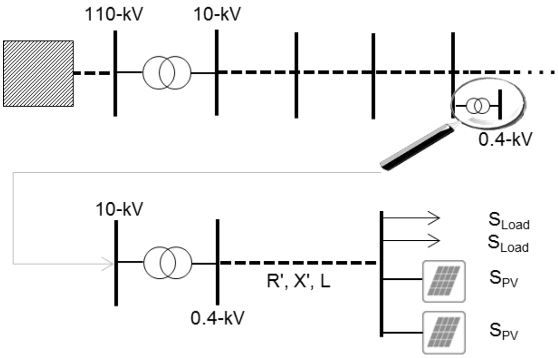


Figure 4-7: Scheme for the chosen grid situation with a storage asset in LV

[24] This situation is relatively common since the grid operator has to enable the operation of 30 kVA power generation from RES-E per household in Germany. If the grid is not designed for these RES-E amounts, the grid operator bears the costs for the reinforcement, see §5 of the German law for the support of power generation out of renewable energies (EEG (2011)).

An alternative to the second cable may be the investment in a storage asset, which behaves as a load device 'consuming' the electricity generated by the PV modules in the case of high feed-in, whereas in case of absence of sun, the stored energy is withdrawn to supply the loads in the grid and flatten the feed-in profile. A battery with a capacity determined using the model described in Section 4.3 would limit the voltage increase to 3% as well without needing to invest in the second cable. Hence, it is technically the same to invest in a second cable or in a storage asset. To calculate the break-even point for the storage asset, further parameters need to be determined, which is part of the next subsection.

4.5.3.2 Parameters for the break-even analysis

As described above, the conventional reinforcement can be realized with a second cable. Note that this extra grid asset is only needed for the situations of feed-in of the PV generators close to their maximum power. The additional cable doubles the current carrying capacity, but this effect has no economic value for the grid operator or the farms since only the voltage increase is the limiting factor and causes the need for the reinforcement. This applies also for situations of less feed-in or higher consumption since the single cable also would be sufficient for these cases. Since both alternatives (second cable as a conventional reinforcement or introduction of a storage asset of sufficient capacity for the objective of peak shaving) provide the same benefit with respect to the voltage effect, the costs of the alternatives can be compared using the approach derived in Subsection 4.5.1. However, the storage asset also influences the load and the voltage in upstream grid levels, which is not provided by the second cable. This effect, explained already in Subsection 4.5.1.1 (see equation (4-15)), leads to an additional benefit of the storage asset compared with the conventional reinforcement. In our case, the considered increase of PV generation also affects the adjacent low voltage grids, the medium voltage level and the transformer of MV/LV and HV/MV since in times of low consumption but high feed-in values, a reverse power flow from LV and MV to HV is visible. In the use case, the MV/LV-substation is equipped with a 250 kVA - transformer. The MV-level is able to cope with a RES-E power of 2.0 MVA due to a long distance to the next HV/MV-transformer and, thus, relatively low short-circuit power. The transformer to the upstream voltage level is equipped with a 10 MVA-transformer. The costs for removing these bottlenecks for growing amounts of PV can be estimated and are given for this use case in Table 4-3. By investing these amounts the original safe conditions in the grids are restored.

However, the main important cost factor occurs in the directly connected grid level (in this case in LV). This cost factor is mainly influenced by the specific costs c_{cable} per meter of installed cable [€/m] because not only the material for the cable is cost-driving but especially the surface for the area which has to be re-opened for the additional cable. The ditch may be expensive not only due to requirements to operate in high quality surfaces (e.g. tarred streets), but also because of the needed crossing of critical systems, such as water channels, motorways or railways. To reveal this effect, equation (4-15) is rewritten using the variable c_{cable} with L_{cable} as the length of the cable:

$$I_{0,cr} = \alpha \cdot (c_{cable} \cdot \mathrm{L}_{cable}) + \beta \cdot I_{\frac{MV}{LV}} + \gamma \cdot I_{MV} + \delta \cdot I_{\frac{HV}{MV}} \qquad (4\text{-}23)$$

This equation allows the direct demonstration of the influence of the important parameter c_{cable} of the conventional reinforcement on the break-even point. The further values listed in

Table 4-3: Calculation of avoided investment in upstream grid levels

level	limit [kW]	parameter with a 30 kW storage asset	parameter for the investment (conv. reinforcement)	contribution to avoided reinforcements [€]
low voltage	30	α = 100.00%	$I_{LV} = c_{cable} \cdot L_{cable}$	?
MV/LV-transformer	250	β = 12.00%	$I_{MV/LV}$ = 5,000 €	600
medium voltage	2,000	γ = 1.50%	I_{MV} = 250,000 €	3,750
HV/MV-transformer	10,000	δ = 0.30%	$I_{HV/MV}$ = 200,000 €	600

Table 4-3 reveal the contribution of the storage assets to the avoided investments in the upstream grid levels (column ‘contribution to avoided reinforcement [€]’) if these are also faced to the same grid reinforcement needs (e.g. because of the same rural character and comparable developments of additional installations of RES-E).

For the losses occurring during the transport of the energy, cost parity is assumed for both scenarios. Hence, the differences in the two alternatives with respect to losses are only influenced by the additional amount of losses resulting from the (in-)efficiency of the storage.

The feed-in data of the PV generators are the basic input values for the model described in Section 4.3. The measured values are given with 15 minutes intervals for a complete year, leading to T=35,040 and represent a typical PV generator located in Germany. The generator is located in a rural grid area in an inland region and hence, the data should be comparable to, e.g. a lot of other European and US regions. The average feed-in of that generator amounts to 11.55% of the nominal power, so 1,011 operating hours per year are given (for a description of the feed-in characteristics in depth see Chapter 3)). The storage model is used to derive the different scopes of operation (‘traffic light’ situations, see Subsection 4.5.2) as well as the capacity E_{req} and the costs for losses $c_{L,s}$ resulting from an operation of a storage asset for the use case. The operation is characterized by limiting the power facing the grid M to 50% of the maximum possible feed-in of the two PV generators in one time interval (i.e. M=60kW·50%·1/4h=7.5 kWh). This value for M is chosen since it limits the feed-in exactly to an uncritical value and, thus, the storage asset is dimensioned to be technically comparable to the investment in the second cable. For determining the break-even point (see Subsection 4.5.3.3), a basis scenario is used. Later on, all values of this basic scenario are subjected to a sensitivity analysis.

To determine the costs for the losses of the storage operation as an important cost type for the break-even calculation, equation (4-8) is used. The costs are calculated depending on the two influencing parameters price p_L per lost unit of energy [€/kWh] and round-trip efficiency r_{eff}. The results are depicted in Figure 4-8 for a 60 kW PV generator limited to 50% of the power. As shown in the figure, the costs increase with a lower efficiency r_{eff} and a higher value for the price p_L per lost unit of energy.

In the following, the values for the different parameters for the basic scenario are given. For this, the values are chosen based on current values for the lithium-ion-technology (see, for example, the data sheets in Diehl (2012), Prosol (2012 and Varta (2012)). More explicitly, these considerations leads to an efficiency r_{eff} =85% and with a price for a unit of

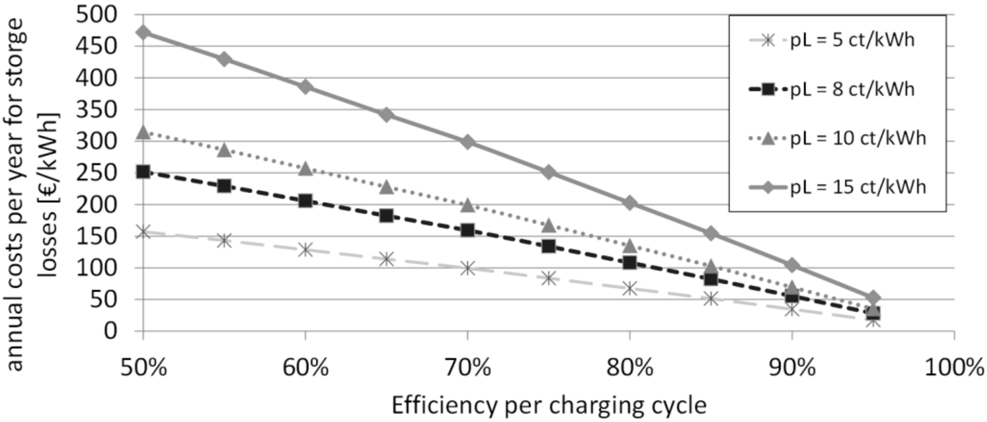


Figure 4-8: Costs of losses depending on the efficiency for a 60 kW PV generator limited to 50% power

lost energy p_L = 8ct/kWh to annual costs for the losses of 82.41 €/year (see Figure 4-8). For the further parameters, reasonable values are chosen and given in Table 4-4. The determined values for P_I and P_O for the speed of (dis-)charging are not critical with respect to common values described in literature (see Section 4.3 and for common values Peterson, et al. (2010)) and, thus, a realistic pattern for the energy flows is given. The degradation factor is chosen according to a value provided in (Hoppecke (2013)), where an up-to-date storage technology with a lifetime of more than 20 years is presented which loses 20% of its nominal capacity in this period. As stated in Section 4.3, the value for d significantly depends on the chosen technology, prevailing temperature and the way of operation (e.g. the depth and frequency of charging cycles or the average state of charge).

Because the break-even point is determined depending on a variable related to grid issues (c_{cable}), also a variable on the storage side is used. For the first results different lifetimes of the storage asset N_s are analyzed since this is an important value for the profitability and very different for existing storage technologies according to literature and manufacturers' data (as presented in Subsection 4.2.2). The influence of the other parameters is investigated by carrying out a sensitivity analysis after presenting the first results.

Table 4-4: Parameters used for calculation the BEP in the chosen grid situation

$\{\alpha, \beta, \gamma, \delta, I_{MV/LV}, I_{MV}, I_{HV/MV}, L_{cable}\}$: see the derivations in Table 4-3			
f_{cr}=(0.01 x I_{cr})/year	f_s=(0.01 x I_s)/year	i_{cr}=5.00%/year	i_s=5.00%/year
N_{cr}=35 years (see StromNEV (2011) as a reference)	r_{eff}=85% (see Diehl (2012), Prosol (2012 and Varta (2012) as references)[25]	DoD=80% (see Diehl (2012), Prosol (2012 and Varta (2012) as references	$c_{L,s}$=82.41 €/year (based on r_{eff} and $p_{L,}$ see Figure 4-8)
p_L=8ct/kWh	M=7.5 kWh	P_I, P_O=7.5 kWh	d=1%/year

[25] Note that often the efficiency of a battery system is given considering only the battery itself; the efficiency of the complete battery system has to include the inverters as well.

4.5.3.3 Results for the BEP for the basic scenario

The results presented in this section focus first on the break-even point using the values given in Table 4-4.[26] The break-even point is derived depending on the costs per meter of installed cable, which may vary a lot for different grid situations. For the length of the cable L_{cable}=750 m is chosen as described in the last subsection. Furthermore, the lifetime of the storage asset is chosen as a variable parameter. Using the model of the storage behavior described in Section 4.3 and the equations derived in Subsection 4.5.1, the resulting break-even points are calculated and depicted in Figure 4-9.

The values for the break-even points depend significantly on the costs per meter of installed cable and the lifetime of the storage asset. The break-even point is given as the threshold, at which a storage asset is becoming more profitable than the conventional reinforcement. Note that a higher value for the break-even point indicates an improved profitability of the storage assets compared with the conventional reinforcement, since the storage asset is allowed to be more expensive for being a suitable alternative. Hence, it is more likely that the actual costs for the storage asset [€/kWh] are lower than the break-even point, providing incentives to invest in the storage asset.

For a lifetime shorter than 10 years the break-even point only exceeds 200 € per kWh of installed capacity for a costs per meter of 70 € and higher (e.g. caused by expensive surfaces or complicated digging, which may be required for crossing channels, motorways or railways). However, for long lifetimes more than 20 years, the costs of c_{cable} can amount to 60 €/m still showing a break-even point of 250 € per kWh.

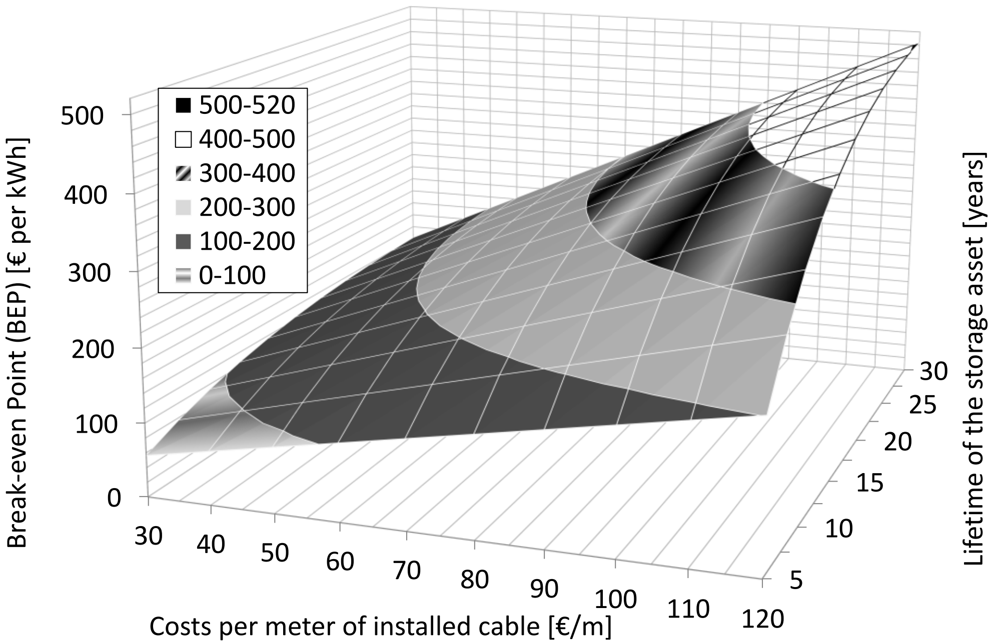


Figure 4-9: Break-even points for the chosen grid situation

[26] For the definition of these parameters, see Section 4.3.

4.5.3.4 Sensitivity analysis

The diagram in Figure 4-9 shows the break-even point value (*BEP*-value) for the chosen grid situation for different values of c_{cable} and N_S. For example, assuming c_{cable} = 60 €/m and N_S = 15 years leads to a *BEP* of 214.74 € per kWh of installed capacity for this example case. According to the prices as described in Subsection 4.2.2, the investment in storage assets is not profitable with current prices for this situation when considering only the grid operation for reducing the peaks. Nevertheless, these values are taken as the basic values for c_{cable} and N_S (lifetime of the storage asset) for the sensitivity analysis to get a more detailed insight and to enable a discussion for adapted operating modes. For the sensitivity analysis, the considered parameters are increased by 10% with a ceteris paribus view so that all other parameters are not affected. The impacts of these changes on the break-even point are depicted in Figure 4-10. It is shown that the *DoD* has the most important influence on the *BEP* for the chosen grid situation – when it increases by 10%, also the *BEP* rises by 10% to 236.22 € per kWh. The costs factors for the conventional reinforcement such as f_{cr} and i_{cr} also lead to an improved profitability of the storage asset with a higher *BEP*. However, some other factors reduce - as might be expected - the *BEP*, e.g. a higher price for the losses (p_L) or a higher degradation factor *d*. In the following the influence of two specific aspects are analyzed in more detail.

Efficiency r_{eff}: The impact of the efficiency r_{eff} is on a first view surprising because it seems that a higher efficiency leads to a reduced profitability. Looking in more detail, this effect is caused by an increased capacity that has to be installed if the storage has a higher efficiency, or, in other words, a lower efficiency leads to a reduction in capacity of the storage asset because more energy is wasted and, thus, less energy has to be stored. Obviously, in this case the costs for the additional investment in more capacity cannot be compensated for the reduced losses due to charging and discharging. Hereby, the inefficiency can be seen as an indirect way to limit the RES-E feed-in since the energy is 'wasted'. Accordingly, some kind of a curtailment or congestion management to throttle the

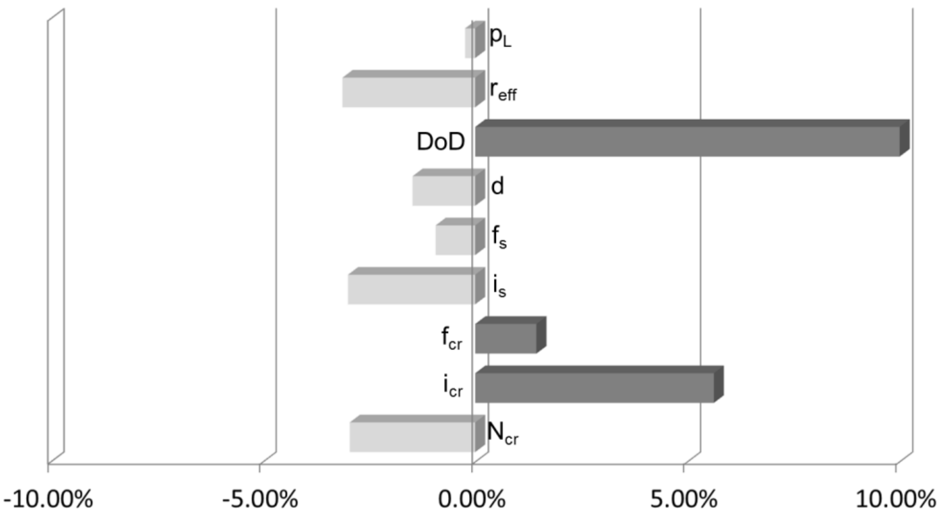


Figure 4-10: Sensitivity analysis for the chosen grid situation with a change of 10% of the parameter and the impact on the *BEP*

feed-in peaks of RES-E is given. This observation is worth a more detailed analysis. For this, the time intervals, where the storage asset is used ($SoC_t > 0$), are analyzed. In Figure 4-11 the cumulative frequencies of the used capacity in these time intervals are given for three different efficiency values. As can be seen in Figure 4-11, the required capacity decreases with a decreased efficiency. The maximum value for the static capacity (based on the results for one year without considering the degradation effects) is 138 kWh for an efficiency of 95%. This value decreases to 131 kWh (123 kWh) for an efficiency of 85% (75%, respectively), which can be seen in the excerpt of the figure focusing on the cumulative frequencies (y-axis) of 95-100%. Even more important is the seldom exploitation of the higher ranges of the capacity. For all three scenarios, the needed capacity decreases to almost 50% if 10% of the situations with an operating storage asset ($SoC_t > 0$) are faded out. For this, the cumulative frequency of 0-90% has to be considered showing that significantly less capacity of the storage assets is required when focusing only on these storage operations (e.g. the capacity gets reduced for an efficiency of 95% from 138 kWh to 80 kWh. These facts indicate that the profitability would increase significantly if not all peaks need to be stored and some of the peaks may be reduced by congestions resulting in a (seldom) throttling of PV (which is nowadays, for example, not allowed in Germany). This effect is obvious if the lost energy is less cost-effective than the required investment in the storage capacity. Alternatively, another option would be to increase the load (when available) in these seldom high-peak periods. The analysis shows already that a more detailed analysis of a trade-off between congestion management and investing in storage assets and/or investing in conventional grid reinforcements is a very interesting topic and should be deepened in future work.

Storage operating mode: Another important aspect to be analyzed is the way of operating the storage asset. As already mentioned, the profitability of the investment may be improved if more opportunities for the operation of the storage assets are possible, which may also increase the incentive to invest in an increased efficiency. In the sections in the previous text, the scope of storage operation was only on grid issues. However, the seldom, but high peaks of PV may enable an operation of the storage asset in times when no grid constraints are hit (for example, due to the lack of PV feed-in or voltage problems). This in-

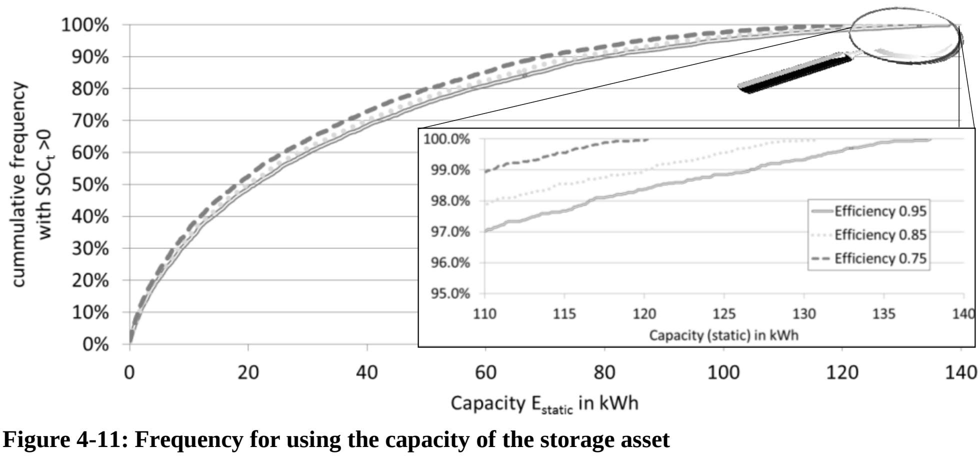


Figure 4-11: Frequency for using the capacity of the storage asset

vestigation was already prepared in Subsection 4.5.2 with the introduction of the traffic light scenarios s_{red}, s_{orange} and s_{green} and is conducted in the remainder of this paragraph. According to the equations (4-20) - (4-22), the time periods for the storage operation can be differentiated for different purposes. In a red phase, the storage asset is needed to reduce the feed-in peak and no further purpose of storage operation is possible. In orange phases some flexibility is left for other objectives (e.g. arbitrage at day ahead or intraday markets or providing ancillary services). In green time periods the storage operation does not need to take grid constraints into account since an exceeding of the value M for the power flow facing the grid is not possible and a need to increase the capacity (E_{static}) can be excluded.

The distribution of the time periods over the three states of the traffic light scenario is given in Figure 4-12. The results indicate that there is much room for further operation; assuming that grid constraints are decisive (red phase, 8.4% of time) there are a lot of time periods with PV feed-in operating below the maximum value M, so that coordination is needed in case of multi-objective operation (38.6% of time). Furthermore, in 54% of the time periods, a storage operation with the given power is possible since no feed-in of PV is given and there are no further grid constraints. Note that the effect of this changed storage profile on the ageing of the storage systems depends on the chosen technology and the way how the storage is used, as described in Section 4.3.

These numbers show that storage is needed for grid purposes mainly to flatten the seldom, but high feed-in peaks. However, if further operation is enabled (e.g. by a third-party market role) in cooperation with further storage stakeholders, the potential of the storage asset could be exploited distinctly better. This changed way of usage would improve the profitability and increase the break-even points since additional economic values (e.g. profits at the day-ahead market) can be included in the analysis.

4.5.4 Discussion

The results presented in the last section show that for the given grid situation and the current prices (Subsection 4.2.2) an investment in the storage asset is only profitable under extremely positive conditions (high costs per installed meter of cable, long lifetime of the storage system). The profitability could be improved significantly if not all of the (high and seldom) peaks need to be stored but if these peaks may be reduced with a congestion management (i.e. by throttling the feed-in). Furthermore, the presented results show that the opportunity for a combined operation of peak shaving for grid purposes and additional operation modes (e.g. arbitrage exploiting price spreads at the spotmarket) is promising because the storage operates relatively seldom when focusing only on a peak shaving of PV

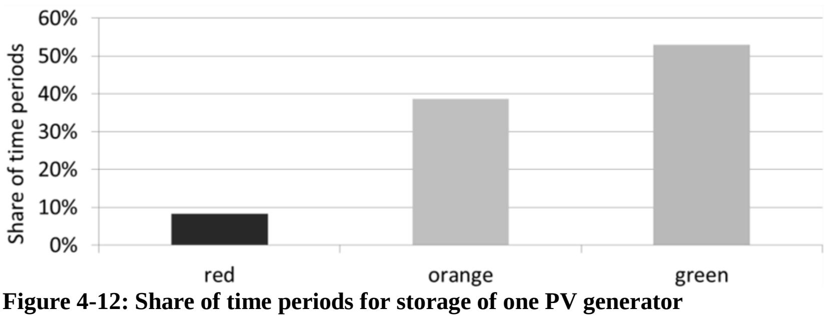


Figure 4-12: Share of time periods for storage of one PV generator

generation. For enabling a multi-objective operation for different stakeholders an adapted market design may be required, e.g. by using forecasts and planning of the energy streams. It may also be possible that the storage assets need to be introduced by a third party offering the flexibility of storage operation to the different stakeholders. This would avoid issues of unbundling and still enable a separation of the different market roles operating in the regulated and non-regulated parts of the supply chain. A proposal for such a cooperative supply chain is one objective of future work. Furthermore, the model for the break-even analysis should be reflected on more use cases to confirm the results and find more appropriate grid situations with an economic legislation of the storage assets. In future work, stochastic climate data should be considered to increase the robustness of the model. Hereby, main characteristics of the storage asset may be derived not only with the presented straightforward approach but with an approach considering possible extreme weather situations and thus, increasing the certainty of appropriately dimensioning the storage asset to cope with feed-in peaks.

Another aspect concerns the prices of the storage assets. These prices are expected to fall in the coming years as a consequence of economies of scale (higher market penetration), economies of scope (different applications, such as electric vehicles, back-up systems) and economies of learning (such as technological progress). However, these developments need to be promoted in a similar way as RES-E has been pushed by subsidies. In most countries, a feed-in tariff for RES-E is implemented (see, e.g. REN21 (2011)), but so far the (legal and hence, political) support of the required storage capacities to cope with the fluctuating feed-in of PV and wind is lacking. Furthermore, the grid operators are incentivized to invest in conventional reinforcement even if the break-even point of storage is achieved or the investment costs are even lower. This effect can be caused by regulation regimes hindering innovations in grid investments (this investigation is focus of the research presented in Chapter 6). To enable an increased investment in decentralized storage assets, these obstacles need to be removed as well.

In this subsection, the grid situation and the reinforcement needs caused by the integration of PV are reflected on a German use case. The methodology and the elaborations on technical issues should also be applicable to a lot of other countries with RES-E developments and rural low voltage areas which applies also for the storage model and the break-even determination.

4.6 Conclusions

The results in this chapter enable storage stakeholder focusing on grid issues to narrow down the choice of storage assets by the determination of main storage characteristics for their business case. The results are based on real world data and show the requirements on storage assets located in distribution grids to reduce the feed-in peak of distributed wind and PV generation. Installing such storage may reduce the reinforcement need in grids and the need for conventional power plants as backup capacities and, thus, is very important for the transition towards a sustainable electricity future.

The difference between the storage capacities needed to reduce the peak of wind and PV profiles is significant. As the evaluations show, wind power is faced with a higher ratio for *E2P* (energy to power) by a factor of twenty and, thus, it is very expensive to be stored if peak shaving is the objective. However, also the diversity factor is of importance. If grid situations allow a centralized or coordinated storage for a fleet of wind or PV generators, the needed storage capacity can be reduced significantly. Hence, this work forms a basis for future research on the choice of appropriate technologies of storage assets to cope with PV and wind feed-ins to reduce reinforcement needs in grids for seldom, but high peaks.

Furthermore, break-even points for storage assets are determined with 100-500 € per kWh of installed capacity for a specific grid scenario. This value is largely influenced by the cost per meter of cable and, thus, the prevailing surface conditions of the ground as well as by the lifetime of the storage asset. Next to this storage parameter, the sensitivity analysis of the given parameters indicates a high impact of the Depth of Discharge. Moreover, also the PV feed-in profile requires a relatively large storage capacity when peak-shaving is applied, whereby the total capacity is very rarely exploited. Hence, the profitability can be increased significantly when throttling of the PV-feed-in is enabled in seldom situations. The derived model for calculating the break-even points can easily be adapted to other grid situations considering the benefits for upstream grid levels as well. The analysis of the storage profile to cope with the feed-in of a PV generator and limiting the feed-in facing the grid to 50% of the nominal power shows that in more than half of the time the storage asset is completely unused (green traffic light phase). Hence, a cooperation of market stakeholders (such as traders to gain profit from arbitrage transactions or acting on the reserve market) and grid operators (to reduce feed-in peaks from PV generation and, thus, reinforcement needs) may be useful to increase the profitability of the storage assets. Investigations facing the potential risks and benefits of separate or cooperated optimizations for the different market roles exploiting the potential of storage assets and demand response are the focus of the next chapter.

4.7 Appendices of Chapter 4

A.4.I: Notations used in the calculations in Section 4.5:

α	coefficient for contributing to eliminate a bottleneck in the LV level
β	coefficient for contributing to eliminate a bottleneck in the MV/LV transformer
γ	coefficient for contributing to eliminate a bottleneck in the MV level
δ	coefficient for contributing to eliminate a bottleneck in the HV/MV transformer
a_{cr}	annuity a reflecting capital expenditures for the scenario 'conventional reinforcement'
a_s	annuity a reflecting capital expenditures for the scenario 'storage'
BEP	break-even point
CAPEX	capital expenditures
c_{cable}	cost per meter of installed cable
c_L	OPEX directly derived from the operation (e.g. losses)
$c_{L,cr}$	OPEX directly derived from the operation (e.g. losses) for the scenario 'conventional reinforcement'
$c_{L,s}$	OPEX directly derived from the operation (e.g. losses) for the scenario 'storage'
c_M	OPEX derived from the initial investment costs (e.g. maintenance costs)
$c_{M,cr}$	OPEX derived from the initial investment costs (e.g. maintenance costs) for the scenario 'conventional reinforcement'
$c_{M,s}$	OPEX derived from the initial investment costs (e.g. maintenance costs) for the scenario 'storage'
$C_{OPEX,cr}$	operational expenditures (costs) for the scenario 'conventional reinforcement'
$C_{OPEX,s}$	operational expenditures (costs) for the scenario 'storage'
CRF	capital recovery factor
d	factor for degradation
DoD	depth of discharge
E_{req}	required capacity of the storage asset for avoiding conventional reinforcements
E_{static}	required capacity of the storage asset for avoiding conventional reinforcements without considering degradation
HV	high voltage
i	interest rate
i_{cr}	interest rate for the scenario 'conventional reinforcement'
i_s	interest rate for the scenario 'storage'
I_t	input flow of the storage
I_0	investment in year 0
$I_{0,cr}$	investment in year 0 for the scenario 'conventional reinforcement'
$I_{0,s}$	investment in year 0 for the scenario 'storage'
L_{cable}	length of installed cable [m]
LV	low voltage
M	permissible power flow facing the grid
MV	medium voltage
N	lifetime of an asset (investment)
N_{cr}	lifetime of an asset (investment) for the scenario 'conventional reinforcement'
N_s	lifetime of an asset (investment) for the scenario 'storage'
O_t	output flow of the storage

OPEX	operational expenditures
PG_t	power flow facing the grid in a time interval t
P_I	power for the charging of the storage in a time interval t (Input)
p_L	price per lost unit of energy
P_O	power for the discharging of the storage in a time interval t (Output)
PR_t	production of the PV generator in a time interval t
s_{red}	share of time periods on T with no flexibility of restoring left
s_{orange}	share of time periods on T with some flexibility left
s_{green}	share of time periods on T with maximum flexibility is left
f	ratio of annual costs for OPEX derived from the initial investment costs
f_{cr}	ratio of annual costs for OPEX derived from the initial investment costs for the scenario 'conventional reinforcement'
r_{eff}	efficiency of the storage (per charging and discharging)
r_s	ratio of annual costs for OPEX derived from the initial investment costs for the scenario 'storage'
SoC_i	state of charge of the storage asset
T	time period of the simulation of the storage operation

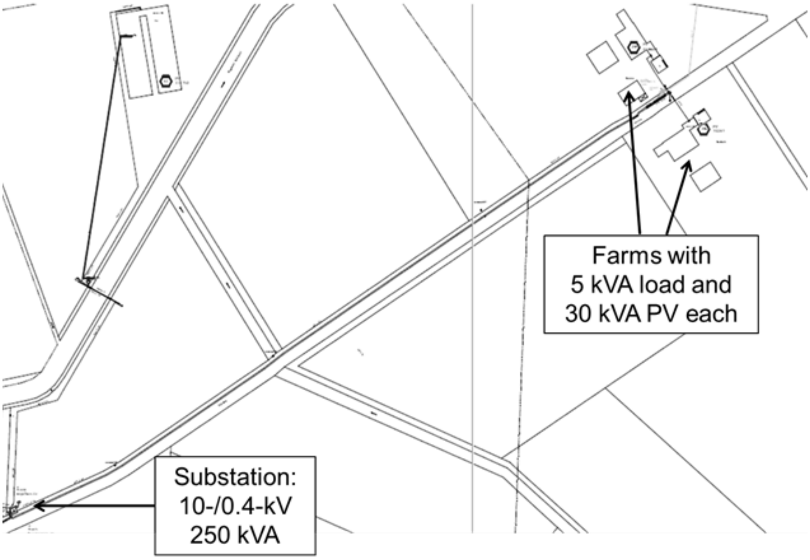
A.4.II: Derivation of equation (4-18)

$$C_{OPEX,s} + a_s = C_{OPEX,c} + a_c$$
$$C_{OPEX,s} + I_{0,\mathrm{s}} \cdot CRF(i_s, N_s) = C_{OPEX,cr} + I_0 \cdot CRF(i_{cr}, N_{cr})$$
$$C_{OPEX,s} + I_{0,\mathrm{s}} \cdot \frac{i_s(1+i)^{N_s}}{(1+i_s)^{N_s}-1} = C_{OPEX,cr} + I_{0,\mathrm{cr}} \cdot \frac{i_{cr}(1+i)^{N_{cr}}}{(1+i_{cr})^{N_{cr}}-1}$$
$$C_{OPEX,s} + I_{0,\mathrm{s}} \cdot \frac{i_s(1+i)^{N_s}}{(1+i_s)^{N_s}-1} = C_{OPEX,cr} + (\alpha \cdot I_{LV} + \beta \cdot I_{\frac{MV}{LV}} + \gamma \cdot I_{MV} + \delta \cdot I_{\frac{HV}{MV}}) \cdot \frac{i_{cr}(1+i)^{N_{cr}}}{(1+i_{cr})^{N_{cr}}-1}$$
$$f_s \cdot I_{0,s} + c_{L,s} + I_{0,\mathrm{s}} \cdot \frac{i_s(1+i)^{N_s}}{(1+i_s)^{N_s}-1} = f_{cr} \cdot I_{0,cr} + c_{L,cr} + (\alpha \cdot I_{LV} + \beta \cdot I_{\frac{MV}{LV}} + \gamma \cdot I_{MV} + \delta \cdot I_{\frac{HV}{MV}}) \cdot \frac{i_{cr}(1+i)^{N_{cr}}}{(1+i_{cr})^{N_{cr}}-1}$$
$$\begin{aligned} f_s \cdot I_{0,s} + c_{L,s} + I_{0,\mathrm{s}} \cdot \frac{i_s(1+i)^{N_s}}{(1+i_s)^{N_s}-1} \\ &= f_{cr} \cdot \left(\alpha \cdot I_{LV} + \beta \cdot I_{\frac{MV}{LV}} + \gamma \cdot I_{MV} + \delta \cdot I_{\frac{HV}{MV}}\right) + c_{L,cr} \\ &+ \left(\alpha \cdot I_{LV} + \beta \cdot I_{\frac{MV}{LV}} + \gamma \cdot I_{MV} + \delta \cdot I_{\frac{HV}{MV}}\right) \cdot \frac{i_{cr}(1+i)^{N_{cr}}}{(1+i_{cr})^{N_{cr}}-1} \end{aligned}$$

Activating the equation towards $I_{0,s}$:

$$I_{0,\mathrm{s}} = \frac{\left(\alpha \cdot I_{LV} + \beta \cdot I_{\frac{MV}{LV}} + \gamma \cdot I_{MV} + \delta \cdot I_{\frac{HV}{MV}}\right) \cdot \left(f_{cr} + \frac{i_{cr}(1+i)^{N_{cr}}}{(1+i_{cr})^{N_{cr}}-1}\right) + c_{L,cr} - c_{L,s}}{f_s + \frac{i_s(1+i)^{N_s}}{(1+i_s)^{N_s}-1}}$$

A.4.III: Example of the real world situation in the case study (Section 4.5.3):



5 On the need for cooperation of stakeholders

Abstract: *The interaction of the different market roles in the electricity supply chain will gain importance with increased flexibility on consumption side and the introduction of storage assets in distribution grids. In the defragmented supply chain, several stakeholders will emerge desiring to exploit the potential of these new options, e.g. traders for arbitrage purposes and grid operators for peak shaving. In this chapter, potential risks and benefits for an optimization of separate market roles with and without considering the restrictions in the distribution grids are analyzed. For this, two different and promising appliances for an increased market penetration are considered.*

In the first part, the usage of storage assets for different stakeholders is modeled. Since the responsibility for the operating of these assets is not defined in most market designs the investigation focuses on storage behavior depending on a steering by an energy trader and a distribution system operator. Hereby, the asset is introduced in a larger distribution grid area and optimal storage behavior for the different objectives is determined, so that the impact of introducing such an asset on the grid can be analyzed. The results reveal conflicting interests - peak shaving of fluctuating feed-in (objective of the distribution system operators to avoid reinforcements) is hampered significantly by storage usage of trading companies (objective of exploiting price spreads in the spotmarket). It is shown that unreasonable high costs occur with undesired economical side-effects if no control or cooperation mechanism is implemented. The most promising perspective for an introduction of storage assets is a cooperation of the stakeholders, thereby considering the grid constraints.

In the second part, the focus is on an important appliance for demand response: electric heat pumps combined with heat buffers are valuable elements in smart grids since they together allow to shift consumption of electricity in time. In this chapter the effects of different control algorithms for heat pumps on the investment costs for distribution grids are investigated. For this, an optimization approach is implemented for a case study analyzing an area where the buildings are only supplied by electricity. Within the simulations real smart meter data is used to generate realistic load curves of households and heat pumps. Furthermore, the costs for the reinforcement of the grid are confronted with the benefits on consumer side (alternatively for the energy retailer) using flexible price signals. The cost-benefit analysis shows that also in this case, considering grid restrictions in the context of controllable devices is highly recommended.[27]

[27] Parts of this chapter are from [Ny:2], [Ny:4], [Ny:7], [Ny:9].

5.1 Introduction

The defragmented supply chain in the electricity sector implies an incentive for all market roles to concentrate on their own and particular business (see Section 2.1). However, the transition to a sustainable electricity system is seen as a common objective for the complete system and society. In this chapter, the interaction of different stakeholders is investigated which will be an important issue for exploiting the potential of storage assets and demand side management. Both aspects attract the interests of different parts of the supply chain. For example, flexibility in the electricity consumption and the generation may be important for transmission grid operators and distribution system operators to reduce peaks in the power profiles and reduce investment costs. Also the competitive part of the supply chain will be an important stakeholder - the flexibility can be used to exploit price spreads in different markets, e.g. by an energy trader or retailer operating on spot- or control markets. The consumer is an important actor as well with possibly deviating objectives for the operation of residential storage, consumption or generation devices compared to the objectives of other market actors (e.g. maximization of locally produced electricity). Hence, the challenges, risks and opportunities for a cooperation or competition in the supply chain to use the flexibility of consumption, generation and storage assets are of interest. These issues are analyzed in this chapter focusing on two different aspects.

In the first part of this chapter optimal storage profiles for different stakeholders (DSO and energy traders) are derived based on a case study. Hereby real world data is used considering measured power flows in a distribution grid area and spotmarket prices. The question of cooperation in the supply chain will gain increasing interest in the future since the responsibility for the operation of these assets is not defined in most market designs.

Secondly, the usage of the flexibility of heat pumps is investigated in Section 5.3. Hereby, heat pumps combined with heat buffers and inert floor-heating systems provide the opportunity to shift electricity demand in time without risking discomfort for the end users since demand of electricity and demand for heat can be decoupled to some extent. In this subsection, it is investigated how distribution grid planning and investments are affected by different steering methods due to different optimization objectives of the different stakeholders DSO and energy retailer. Section 5.4 ends up with conclusions.

5.2 Usage of the flexibility of distributed storage

The increase of electricity generation out of renewable energy sources (RES-E) poses major challenges on grid operators to integrate the fluctuating generation as presented in Section 2.2. One ‘smart’ solution of reinforcements is the implementation of local (distributed) storage capacities as derived in Chapter 4. In combination with information and communication technologies (ICT), used to measure and analyze the real situation in the grid, the storage assets can avoid local voltage and load problems.

In the above context, it is not clear which role DSOs play with the integration of distributed storage systems and what scope of responsibilities they will have. It is also unclear whether other storage stakeholders, for example energy traders, may support a cost-efficient integration of RES-E or even cause additional grid problems leading to increased reinforcement needs. To investigate this topic, in this section the optimal usage of local storage capacities for different storage stakeholders is derived based on a case study. Since the optimization objectives differ for DSO and energy trader, different profiles for the usage of the storage capacity are expected. The executed simulations are based on real measured local production and consumption data in a distribution grid area as well as on real spotmarket prices in Germany. As described above, the corresponding technical and economic effects are likely to occur also in a lot of other countries in the future.

As the grid is faced with a lot of PV, wind and biomass generators leading to a bidirectional, fluctuating energy flow, the optimal usage profile of the storage asset from the perspective of the DSO is oriented on peak shaving to reduce reinforcement needs for further RES-E integration. In contrast to this, the optimal storage usage of an energy trader focuses on the maximal profit by buying electricity at low price periods and selling it when prices are high (arbitrage). The profiles of the energy flows are influenced by the storage operation. Considering the different objectives for the stakeholders, the expected energy profiles are compared to reveal complementary or supplementary operating conditions. The results enable a discussion started in this chapter on the reasons and consequences of an intervention of DSOs when integrating storage assets in distribution grids.

The subsection is built up as follows. In Subsection 5.2.1 the background of this work is presented by giving a short overview on related work. Furthermore, the reasons for focusing on the two chosen stakeholders (DSO and trader on the spotmarket) are explained. Subsection 5.2.2 contains the description of the case study. For this, the situation in the underlying distribution grid is explained as well as current (spot-)market designs and the integration of RES-E in these markets. The approach for calculating the optimal storage usage for 1) peak shaving (perspective of the DSO) and 2) maximizing arbitrage (perspective of the energy trader) is presented in Subsection 5.2.3 followed by the results in Subsection 5.2.4. A discussion and proposals for an improved and efficient integration of distributed storage assets are given in Subsection 5.2.5.

5.2.1 Related work

The importance of storage assets for the integration of RES-E is in general undisputed since the fluctuating feed-in of PV and wind requires storage of electricity as well as an improved adjustment of consumption to the production. An overview on distributed storage systems has been presented in Section 4.2 and technical and economic characteristics of storage assets to be introduced appropriately in distribution grids are derived.

The support for new technologies in the storage sector is likely to lead to reduced prices for storage assets due to economies of scale and economies of learning. This development may enable a profitable implementation of storage devices not only from the view of grid operators by avoiding conventional grid extensions, but also other storage stakeholders like energy traders may participate. In this context, the storage asset is used for arbitrage purposes to exploit price spreads at the imbalance- or spotmarket. This scenario is presented in Nieuwenhout et al. (2006). It is stated that for the Dutch energy market in the years 2000-2004 the imbalance market was the most profitable market due to largest price spreads. However, the forecasting of the imbalance market with its stochastic character is much more difficult compared with the spotmarket and its more regular patterns. Thus, the theoretical potentials of revenues in imbalance markets are higher, but are subject to much more risk. The study in Nieuwenhout et al. (2006) concentrates only on traded electricity - grid benefits and restrictions have not been considered.

In Geth et al. (2010) a multi-objective approach is presented considering grid objectives as well as arbitrage purposes and an optimal sizing and siting of storage assets is derived.

However, since the focus in this thesis is on the real world energy supply chain with separate, unbundled market roles and their different optimization objectives, the focus of the research differs significantly.

The German regulation agency BNetzA (2011) states, that a market mechanism should not be aligned to support grid purposes. In contrast, the grid should enable the market mechanism to exploit its potential. As it will be shown in the use case presented in Section 5.3, this philosophy may lead to undesired economic effects from a welfare point of view because the grid reinforcement costs can exceed significantly the cost savings on the consumer and/or supplier side. Hence, it seems questionable whether or not official parties, such as the regulation agency, have recognized the reasonable cooperation of market roles as an important factor of success for the implementation of smart grids. With a more future perspective, ETP SG (2012) assumes that with more decentralized generation, there is a greater need for a more integrated view on transmission, distribution and storage.

The former mentioned optimization approaches in Nieuwenhout et al. (2006) and Geth et al. (2010) derive the theoretical reachable maximum profits. These theoretical profits imply perfect forecast of future prices and (as in our case) of feed-in and consumption data. In real world applications, predictions are never perfect. Therefore a control methodology is needed that approximates the benefits of a theoretical optimization with perfect knowledge by using only the information that is available in real-time. Such an approach is presented later in Subsection 5.3.2 with TRIANA and the three steps forecasting, planning and real time control. However, for the purposes in the work presented in this subsection, the theoretical optimization is appropriate to show the different resulting profiles for the storage stakeholders, regardless of with what kind and accuracy of forecasting and real time control this maximum can be achieved in reality. Summarizing, the usage of storage assets for different purposes and the compatibility of these profiles in distribution grids has not been analyzed in detail. Such a situation is investigated with a case study, which is presented in the next section.

5.2.2 Case study

This subsection contains a short description of the used data in the case study. Hereby, the focus is on a real rural 30-kV-distribution area in the Emsland, Germany, which is exemplary for a lot of other distribution grid areas (i.e. the nationally harmonized feed-in support leads to comparable load profiles in other regions). Note that these values differ from the feed-in values analyzed in Chapter 3 because a complete distribution grid area including the consumption values is considered.

In the downstream 10-kV and 1-kV voltage levels the given consumers and feed-in capacities are connected. In the past, the energy flow only went from the 30-kV voltage levels passing the transformer to supply the distribution grid area. Nowadays, at certain times with lots of PV, wind and biomass generation, a load reversal occurs. In principle, this bidirectional energy flow is not critical for the installed assets. However, the feed-in capacities still experience significant growth rates. Since DSOs are forced by law to connect all the generators to the grid, transport the energy and reinforce the grid assets, a massive investment need is expected (see Section 1.2).

To give an indication of the bidirectional energy flow, the load profile of the distribution grid area is presented in Figure 5-1 for a one week period. The measured values of the 30/10-kV transformers are used to derive this load profile. Hereby, a positive value of the power passing the transformer indicates a surplus energy in the distribution grid area,

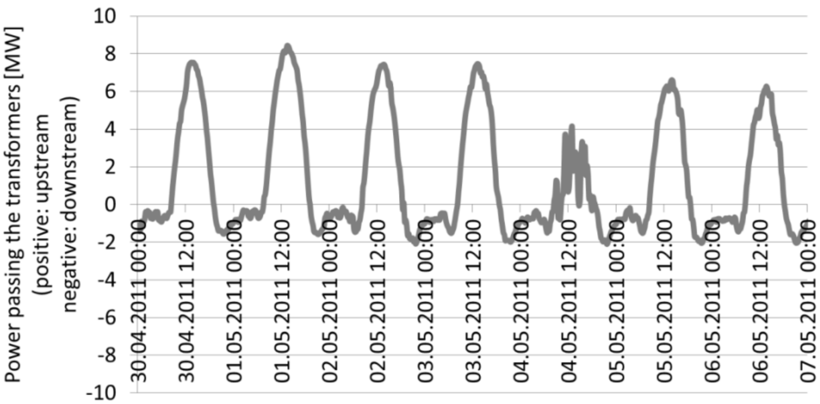


Figure 5-1: Power passing the transformer for a time period of 7 days

which is transported via the 30-kV grid to the next substation with a higher voltage level (110-kV). Thus, in these periods with positive flows a ‘net’ production of the area is given, in contrast to the periods with ‘net’ consumption indicated by negative values. The periods with negative values in Figure 5-1 occur especially in the evening and night hours with absent of sun.

In the course of this section, first the insights in the grid related issues are deepened followed by elaborations dealing with the trading part of the supply chain. Figure 5-1 visualizes the load reversal which occurs especially at noon since a lot of PV generators are connected to the grid. Furthermore, since assets in grids have to be dimensioned for the maximum energy flow occurring, the figure indicates that for this area the production scenario is more critical than the consumption scenario. This is supported also by the fact that the maximum downstream value (consumption) over the whole year is -5.03 MW (occurred in March) and the maximum upstream value (production) is 8.43 MW. The latter value occurred on May, 1st, which was a Sunday with low consumption but high sun radiation and hardly clouds in the considered area. Considering the complete time period of one year, the average value in the 15 minutes intervals is -0.28 MW, indicating that despite the high, but unsteady feed-in peaks, the area is still a net consumption area. Since PV is one of the most growing generation types in Europe, this profile is likely to be seen in a lot of other distribution areas. Note that still a further increase of the feed-in in this rural area is expected. Therefore, in this area the implementation of storage capacities may be an alternative for the reinforcement with additional assets accompanied by positive effects for the rest of the supply chain as mentioned and shown in the Chapters 2 and 4.

Next to the DSO, also energy traders may have an interest in installing storage capacities, if economically feasible. To reveal the optimal storage usage profile of such an energy trader, the German EPEX spotmarket prices are considered. The spotmarket offers short-term contracts with a fulfillment of the transactions immediately (intraday market) or with one day delay (day-ahead market). Compared with long-term contracts (e.g. Futures), the intraday and day-ahead prices are characterized by a relatively large price volatility. In the scenarios considered in this chapter, the trader is assumed to be a ‘price taker’, so the own consumption or feed-in will not have an effect on the price itself. This seems to be a reasonable assumption due to the negligible power (2 MW) of the battery compared with the total load in the transmission system. The objective of the energy trader is on (time) arbitrage to use time periods on the spotmarket with low prices for buying energy to be stored and to withdraw energy in periods with high prices.

In the considered data set with German hourly prices of 2011 an average price for the day ahead product (EPEX Spot Phelix Day Ahead) of 51.12 €/MWh with a standard deviation of 13.60 can be found. The intraday price (EPEX Spot Intraday) with 51.19 €/MWh shows a similar level, but is even more volatile (standard deviation of 15.49) (EPEX (2011)).

In the current German market design, the relation of the feed-in of local RES-E capacities and spotmarket prices is given by the realtime merchandising of the RES-E capacities. For this, the forecasted RES-E profiles are determined for each transmission grid area and placed as a bid in the day ahead auction by the transmission system operator at the German spot market. Thus, a negative correlation should be expected (the higher the RES-E feed-in, the lower the prices). However, the correlation of distributed feed-in and spotmarket prices is influenced by many other parameters, such as total load, amount of conventional generation or RES-E feed-in in other distribution areas or transmission grids. Furthermore, the RES-E operator is not necessarily incentivized to react on price signals since current feed-in laws in Germany enable an unlimited priority of RES-E with fixed feed-in tariffs. These elaborations indicate also the applicability of these developments to other countries with similar market structures of (regulated) distribution system operators and (non-regulated) trading companies operating at an energy spotmarket as well as countries faced with a transition from conventional, large scale power generation to renewable, decentralized generation (such as PV).

Another aspect to be treated is the placement of the batteries. The distribution grid is faced with a lot of RES-E capacities as well as consuming devices. The storage asset should be used to avoid or delay additional reinforcements (e.g. in bigger dimensioned 30/10-kV transformers) and enable a more flattened profile passing the transformer. For the energy trader it is important to install distributed storage capacities in voltage levels with relatively low installation costs (thus, 10-kV is more appropriate than 30-kV) but relatively high capacities (thus, 10-kV is more appropriate than 1-kV). Hence, the installation of distributed storage assets on the 10-kV-side of the substation seems to be a proper choice for this analysis. For the sake of clarity, the chosen situation in the case study with the assumed placement of the storage asset is presented in Figure 5-2.

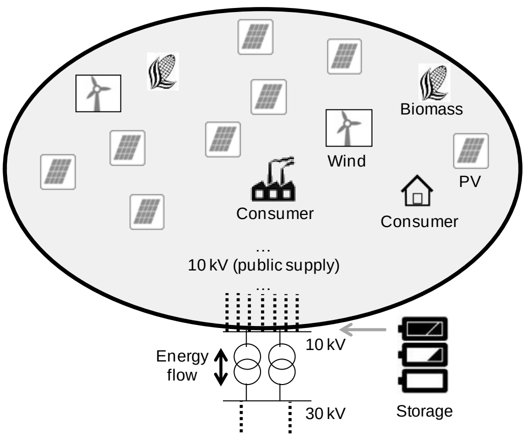


Figure 5-2: Scheme of supply in the case study

The typical size of the distributed storage assets considered for this scenario are assumed to be in the low MW-range (power) with a capacity being able to store the energy flow of a few hours [MWh] as described in Section 4.4. The technical feasibility of such installations in this range of power and capacity has been demonstrated in practice (see for example Tanaka (2001)). Examples for the choice of appropriate storage devices are batteries, redox flow systems and distributed biogas buffers, which have been discussed in more detail in the previous Section 4.2. Considering the mixture of the different RES-technologies located in the grid and the (not known) influence of the consumption on the *E2P*-ratio, a power of the storage asset equals 2 MW with a capacity of 8 MWh is chosen. As it is shown later, a storage asset of this dimension with an *E2P*-ratio of 4 h (8 MWh/2MW) is able to cope with the resulting feed-in peak and, thus, is appropriate for the objective of the DSO to avoid reinforcement. Furthermore, a storage asset characterized by these parameters is likely to be large enough to significantly reduce local grid problems (such as a reinforcement need for the transformer) but is still in a range to be realizable in regard to requirements for space and investment costs. The influence of larger capacities on the storage usage profile for trading companies is not the scope of this research and left for future work.

In the next section an approach to determine an optimized storage profile is presented. For this, the focus is on the optimization for two different stakeholders: grid operator (minimize peaks) and energy trader (maximize profit by arbitrage).

5.2.3 Approach and scenarios

This section contains the derivation of the optimal storage profiles. The optimization objectives for the different market roles with the two considered stakeholders vary, such that two different kinds of simulations have to be processed. To determine their optimized storage usage profiles, first the model of the battery and the constraints for an efficient operation are derived. Note that a different model of the battery compared to the model presented in Section 4.3 is used. This new model derived in the next section is required because an optimization approach needs to be introduced and further parameters (such as prices on the spotmarket) have to be considered. Furthermore, some simplifications are given to enable a modeling with an integration of the measured values in a reasonable time period.

5.2.3.1 Model of the battery

In this section, the model of the battery is derived, which is used for all different optimization scenarios. First, a discretization of time is used, meaning that the observed time horizon is modeled by time intervals of fixed length. For each time interval i ($i \in \{1,\ldots,T\}$) let PR_i denote the given amount of electricity production/consumption in the area. Furthermore, for each time interval i two variables are introduced: T_i denoting the amount of transported electricity passing the transformer (in MWh), and B_i denoting the battery flow. The relation between these three values for time interval i is given by

$$T_i = PR_i + B_i. \tag{5-1}$$

Note that positive values for the transport T_i, the production PR_i and the battery B_i indicate energy flows to the upstream grid. Thus, a negative value for the production indicates a net consumption of energy of the considered area. Furthermore, let P denote the given limit on the maximum amount of electricity (in MWh) that can be drawn from or put into the battery in one time interval. This value P origins from the power limitations of the battery and the used time interval length. The following constraint uses this parameter to limit the battery energy flow in time interval i:

$$-P \leq B_i \leq P \tag{5-2}$$

Next to the limitation per time period, the battery also has a maximum total capacity denoted by C. It has to be ensured that the state of charge of the battery S_i in every time period i is in the interval $[0,C]$.

$$0 < S_i \leq C \tag{5-3}$$

Later on it is explained how S_i depends on B_i and behaves over time. In the model, the length of a time interval is chosen as 15 minutes and the data is given for a complete year (T=35,040). To characterize the state of charge S_i, the efficiency E of the charging process has to be considered. For our model, this value is chosen to be 0.8 meaning that 20% of the charged energy is characterized as loss, occurring during the charging process. This simplification is used to enable a simulation within reasonable time horizons and deviates from the more precise model of Section 4.3. However, for the scope of the research given in this chapter, the different storage behavior for the different market roles is of importance, and hence, this simplification is seen as negligible for the detailed model of the battery. To determine the loss occurring in a given time interval the battery flow has to be split up. Hereby, let I_i denote the inflow and O_i the outflow in the time interval i. Using these variables, the charging states S_i are determined as follows.

$$S_i = S_{i-1} - O_i + I_i \cdot E \tag{5-4}$$

with

$$B_i = O_i - I_i \qquad I_i, O_i \in \mathbb{R}_0^+ \tag{5-5}$$

This determination is required to integrate appropriately the efficiency E in equation (5-4), still taking the time requirements into account. Note that in each time interval at least one of the two variables I_i or O_i has to take the value 0. To complete a correct formulation of the value of 0 for the input and/or the output in one time interval, additional constraints are needed to force that this is ensured. However, due to the huge amount of data we have chosen to disregard such constraints, prioritizing that the model remains only using linear constraints and non-integer decision variables. In the analyzed scenarios, the combination of the used objective and the bound on the loss due to the efficiency value E (see equation (5-6)) already lead to the desired results of having no inflow and outflow in the same time interval, which is proven by a detailed analysis of the results for each time interval.

5.2.3.2 Model for battery operation

As a next step, the operation of the storage assets is restricted by a bound on the permitted loss L to avoid undesirable high operational costs as well as the rapid wear and tear due to frequent starting of the (re-)storing. More precisely, a loss-limitation factor μ is introduced which forces the total loss caused by battery usage to be smaller than μ times the flow through the transformer during the observed horizon of one year. In the case study, a value of μ=0.03 is assumed, so that the losses are limited to 3% of the total production.

$$L = \sum_{i=1}^{T} (1\text{-}E) \cdot I_i \leq \mu \cdot \sum_{i=1}^{T} |PR_i| \qquad (5\text{-}6)$$

As all introduced constraints (5-1) - (5-6) are linear, these constraints can be incorporated in a Linear Program (LP). Further effects describing the characteristics over time like wear and tear, the decreasing usable capacity of the battery or self-discharging are not integrated since the focus of this research is not on describing a specific battery type with long term effects but on their way of use with short time horizons for different stakeholders. This applies also for further storage parameters like the depth of discharge or the influence of the cycling numbers on the lifetime of the storage asset which have been discussed in detail in Chapter 4.

5.2.3.3 Optimization for grid purposes

In this paragraph the derivation for the optimal storage profile of the grid operator is presented, followed by the optimization for the energy trader in the next paragraph. The objective of the DSO is to minimize the absolute transported peak to avoid (or at least defer) conventional grid reinforcements.

To formalize the objective for the grid operator, the peak value of the flow needs to be determined, both for upstream and downstream. For this, a variable *TP* is introduced, which represents the absolute bound on the transported electricity (see (5-8) and which has to be minimized (see (5-7)).

$$\min TP \qquad (5\text{-}7)$$

$$-TP \leq T_i \leq TP \qquad (5\text{-}8)$$

The model (5-1) - (5-8) leads to a LP and can be modeled using AIMMS (2013) with CPLEX 12.3 for solving the linear program. The measured data for the production and consumption of the distribution grid area with the 15 minutes values is used as input data for the model. Before describing the results, the optimization models for the arbitrage scenario and for a scenario of combined operation are presented in the next paragraphs.

5.2.3.4 Optimization for arbitrage purposes

The model for the trading stakeholder is discussed in this paragraph. Hereby, the objective is on maximizing the profit caused by price spreads (arbitrage). The corresponding equation is given in (5-9) where p_i is the spotmarket price in period *i*.

$$\max \sum_{i=1}^{T} p_i \cdot B_i \qquad (5\text{-}9)$$

The prices for the day ahead market and the intraday market are considered in two separate scenarios leading to different transport and storage profiles and - consequently - to different correlations and peak behavior compared with the grid scenario of peak shaving. The technical constraints for the flow in and out of the battery are again given by the equations (5-1) - (5-6). For the maximization of the profit, further possible types of costs like grid charges, electricity taxes or the levy for supporting renewable energies are neglected. This seems to be an acceptable assumption because it is still under discussion, whether the exemption for the payment of these cost types is an expedient incentive to increase the penetration of storage assets (see more detailed in the discussion of Subsection 5.2.5).

5.2.3.5 Optimization for a combined operation

The two objectives in the previous paragraphs focus on two extreme cases. However, it also may be of interest to investigate how much room for price optimization is left if some grid constraints are added to the model. This may be important for the profitability of the storage asset itself but also from the perspective of the (national) economical operation of storage assets to avoid a profit for a market participant inducing significantly higher costs for other stakeholders (external effects). These scenarios are simulated by using the optimization in (5-9) and consider equation (5-8) as a constraint, meaning that the profits should be maximized, but a predefined value of the transported peak *TP* may not be exceeded. The value of *TP* can be determined, e.g. by the grid operator. These scenarios with the derived reduced profits are shown after the ‘basic’ scenarios in Subsection 5.2.4.

5.2.3.6 Scenarios

The resulting profiles for the transport of the energy for the different optimization profiles are the main scope of the following analysis. The profiles are investigated in detail due to their relevance for the dimensioning of the grid assets (e.g. the 30/10-kV-transformer). For this, four different scenarios are analzed:

(a) profile without storage: in this case, the transport profile equals the production/consumption profile (T_i=PR_i).
(b) profile with peak shaving (grid scenario): the reduction of the transported peak is the objective of the usage of the storage asset.
(c) profile with the maximization of profits using price spreads (arbitrage) with day ahead prices.
(d) like c, but using intraday prices.

Hence, profile a) is actually measured and reflects the situations where no influencing storage behavior is present (in contrast to scenario b), c) and d)). The other three scenarios are simulation results. The results of these different scenarios are presented in the next section. Afterwards and according to the model described in 5.2.3.5, the analysis for the combined operation for day ahead c)* and intraday prices d)* are presented.

5.2.4 Results

As already mentioned, a storage asset of 2 MW power with a capacity of 8 MWh is used for the analysis of the transportation profiles. Figure 5-3 shows the profile for the transported electricity of the 30/10-kV-transformer for the time period from 01.04.2011- 30.09.2011, the period of the year with most PV generation. An overview on the main important values (e.g. the maximum peak) is given in Table 5-1.

The profile for scenario a) gives a maximum peak of 8.43 MW as already mentioned in Subsection 5.2.2. For scenario b) the influence of the operation of the storage assets is visible leading to a reduced peak. Looking at scenario c) and d) seldom peaks are revealed, which even exceed the value of 8.43 MW. The figure gives a first impression on the impact of different optimization objectives on the resulting profiles of storage and transportation. In the other seasons of the year no remarkable power values are visible. The first (last) exceeding of 8.43 MW for the scenarios c) and d) is noticed on 03.05.2011 (02.09.2011, respectively) and thus, visible in the time period included in the figure.

The main results for the different scenarios are summarized in Table 5-1. The maximum transport values are listed confirming the former elaborations; in scenario b) with peak shaving the maximum transport decreases precisely by the maximum power of the battery (2 MW) to 6.43 MW, so that the potential of the storage assets is completely exploited. This

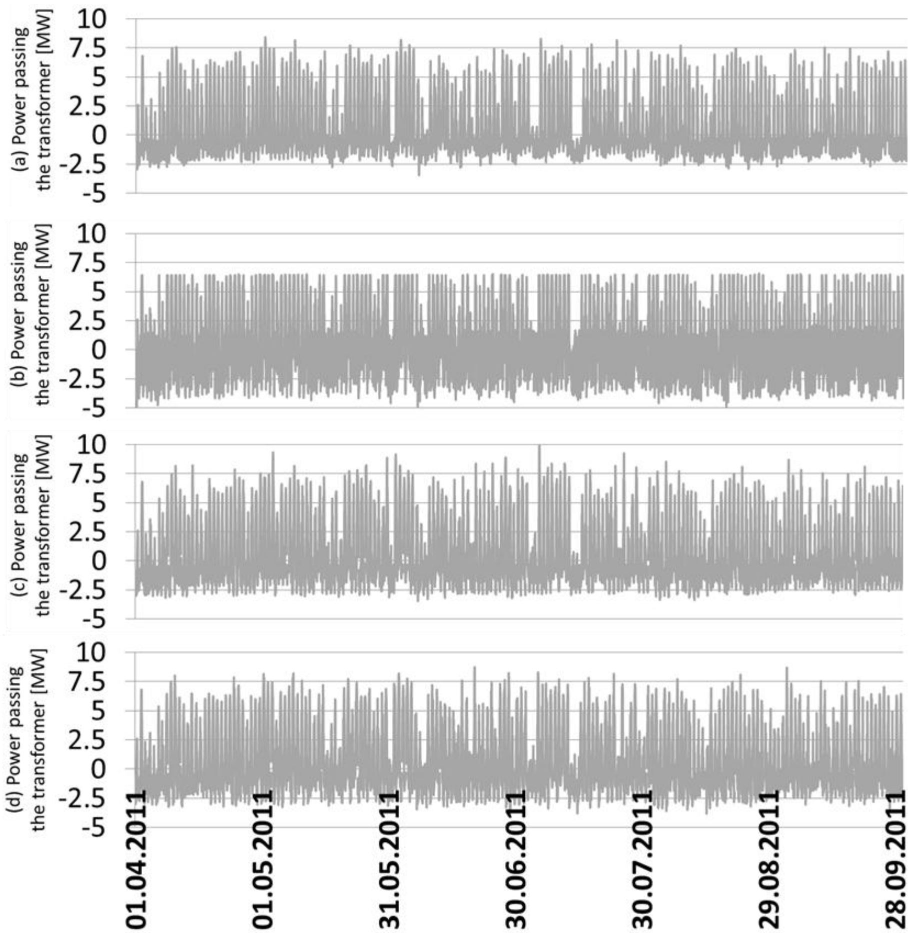


Figure 5-3: Transport values for the four scenarios[28]

[28] a) the scenario without storage, b) the scenario with peak shaving (objective of the grid operator), c) the arbitrage scenario with prices of the day ahead market and d) like c, but with prices of the intraday market.

Table 5-1: Main results for the different scenarios

Results overview	a) scenario without storage	b) scenario peak shaving	c) scenario day ahead price	d) scenario intraday price
Maximum transport [MW]	8.43	6.43	10.29	8.71
Average transport per 15 minutes [MW]	-0.28	-0.33	-0.33	-0.33
Standard deviation for the transport profile [MW]	2.28	2.45	2.44	2.41
correlation coefficients		$r_{Tb,Tc}$=0.8403		
			$r_{Tc,Td}$=0.9252	
		$r_{Tb,Td}$=0.8399		

indicates that the chosen capacity of 8 MWh for the battery seems to be large enough. However, for scenario c) using the day ahead prices a maximum transport of 10.29 MW and for the scenario d) with intraday prices of 8.71 MW is given. The average transport value gets more negative for all storage scenarios', meaning that on average more electricity is transported downstream. This increase results from the need to cover the losses when operating the storage assets. As in all cases for using storage assets from an ecological and economical point of view, the usage should bring more benefits than the effort for the extra energy used (e.g. by lower grid costs due to reduced reinforcements which outperform the costs for the extra energy). Note that in all scenarios the maximum allowed loss of 3% of the total absolute production/consumption is considered (see the constraint in equation (5-6) in Subsection 5.2.3)). The value for the standard deviation of the transport values increases indicating a risen volatile transport profile.

To compare the transport profiles of the different scenarios, it is useful to calculate the correlation. More precisely, the correlation coefficients $r_{Tx,Ty}$ of the transport profiles are calculated using the 15 minutes values of T_i for each pair (x,y) of scenarios ($x, y \varepsilon \{b, c, d\}$). The resulting coefficients are given at the bottom of Table 5-1. All transport profiles are highly correlated. For the correlation coefficient $r_{Tb,Tc}$ between the transport values of scenario b) peak shaving and c) arbitrage using day ahead prices, we get $r_{Tb,Tc}$=0.8403; for the correlation of the transport values for b) peak shaving and d) intraday prices, we get $r_{Tb,Td}$=0.8399. Finally, for the comparison of the arbitrage scenarios with the transport values of scenario c) day ahead and d) intraday, we get $r_{Tc,Td}$=0.9252. This high correlation was to be expected, since the bounded capacity of the battery allows only a restricted change in the transport profile. However, the large deviations in the maximum peak of the transported energy need an explanation.

To get more insight in the impact of the storage asset on the maximum peak occurring, a new parameter $\lambda_{i,x}$ is introduced, where x represents the considered scenario ($x \varepsilon \{b, c, d\}$. This parameter is defined as the difference of the peak of the scenario $T_{i,x}$ and the peak TP_a of the scenario without using storage assets, divided by the power of the storage asset P. This division is useful to describe the usage of the storage power for an increase of the feed-in peak (e.g. to reveal if the storage asset is fully used to increase the peak with the highest possible value). As described above, the value for TP_a is given with 8.43 MW and the power of the storage asset with P=2 MW.

$$\lambda_{i,x} = \frac{T_{i,x} - TP_a}{P} \tag{5-10}$$

Table 5-2: Influence of the storage asset on TP

	b) scenario peak shaving	c) scenario day ahead price	d) scenario intraday price
number of incidents for λ > 0	0	35	2
number of incidents for λ > 0 in %	0.00%	0.10%	0.01%
maximum value for λ , with λ > 0		93%	14%

If $\lambda_{i,x}>0$, this indicates that the usage of the storage assets induces an increase of the peak compared with the scenario without storing. Thus, $\lambda_{i,x}$ is used as a simple and transparent parameter to illustrate the exploitation of the storage asset and is given as percentage of P. As described before, in scenario b) the storage power is completely exploited to reduce the peak. For scenario c), an inferior result is shown - in the extreme situation, the maximum value increases by 93% of the power of the storage device compared to the scenario without storage (see also Table 5-1). The number of time intervals with $\lambda_{i,x}>0$ is determined to reveal the frequency of these situations. By using 15 minutes time intervals per year in total 35,040 time intervals are given. Table 5-2 indicates, that only very seldom time intervals with $\lambda_{i,x}>0$ occur.

Summarizing, the maximum values for the transported power differ significantly. However, a high correlation coefficient for the transport values is shown. Since the grid assets have to be dimensioned for the seldom, but high peaks, a detailed view is given below to reveal further relations.

For an analysis of the peaks, a detailed look at the transport profiles in combination with the given price structures is useful. In Figure 5-4 the transport profiles around the maximum peak over all scenarios are depicted (10.29 MW, scenario c) day ahead on June 5th and June 6th) together with the day ahead and intraday prices. A deviation of the transport value for the specific scenarios compared with the curve for the transport in scenario a) (without storage) indicates a

- storing (curve is below the value for a)), since less energy passes the transformer and, instead, is used for charging the storage asset.
- restoring (curve is above the value for a)).

When comparing the curves of the transported power of the different scenarios, a few main observations can be made.

- In the profile of the peak shaving (scenario b)) one can see that the maximum value of 6.43 MW occurs after noon. The energy stored during the corresponding period is restored in times with less RES-E (e.g. in the evening hours or at night).
- In the considered time period the intraday price is at its maximum just before noon with 75 €/MWh. Thus, restoring and selling of energy is rational at these times because here maximum profits can be earned. A further restoring and selling of energy at noon, where the prices are still high, is not possible due to the given limitations of the capacity of the storage asset. Hence, if a larger capacity of the storage asset is chosen, a restoring going along with the PV peak in the hours after noon would have been detected. The storing of energy is done particularly at night (e.g. on June 5th with 41 €/MWh or on June 6th with 25 €/MWh) since the electricity is cheap in these periods and buying is rational.
- The day ahead prices reach their maximum later at noon with 67 €/MWh. The described price profiles confirm the elaborations on the basic statistics of the day ahead and intraday prices in Subsection 5.2.2 - the average values are comparable for both scenarios, but intraday prices are characterized by a higher volatility. Due

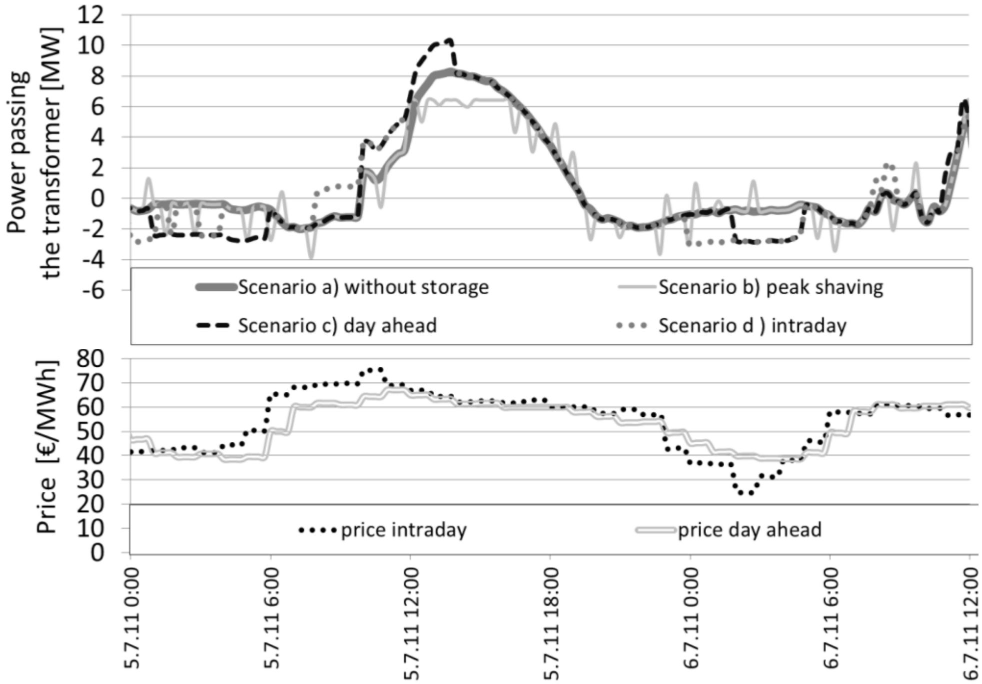


Figure 5-4: Detailed analysis of the transport profile and price structures

to the later price peak compared to the intraday prices, the surplus energy runs together with the production peak and, hence, a high peak value occurs. The storing of needed energy takes place at night with lower prices (e.g. 38 €/MWh during the night of June 6^{th}) too.

This effect has been observed for six further days and thus, the 35 occurrences of $\lambda_{i,x}>0$ mentioned in Table 5-2 are explainable. Furthermore, this detailed analysis gives an explanation of the high correlation coefficients. Since the power of the storage asset is limited with 2 MW, the transport profiles cannot differ significantly. The constraints for the allowed losses reduce the volatility further. Hence, to some extent, the correlation coefficients are deceptive and the analysis of the peak values is more practical.

The analysis in Figure 5-4 indicates also that the large decentralized production in the considered area is superimposed by other impact factors on the price. Since photovoltaic experienced significant growth rates and especially in summer around noon contributes distinctly to the energy supply, also a noticeable impact on the price may be expected. With a ceteris paribus view, a larger amount of supply should lead to a decreased price for the energy. For the described time period in Figure 5-4, this effect is not visible. The production peak occurs at around noon, but in these periods still very high prices are given. This may be caused by less contribution of decentralized energy in other regions of the country or by high consumption, little energy supply by conventional power plants (e.g. caused by low water levels for the cooling of power plants) or a combination of these influencing factors. As a consequence, investigating the influence of local RES-E production profiles on national market prices is an interesting task left for the future with growing RES-E shares. This process has been started by considering the values for 2012, enabling a comparison to 2011 as given in Table 5-3. For this, the correlation coefficients of the local transport values and the spotmarket prices valid in the same time interval are calculated. As mentioned above, a negative correlation was to be expected since large positive transport values indicate a local surplus of energy. This oversupply should lead to lower prices if a correlation of these two parameters is given and other influencing factors are negligible. However, as shown in Table 5-3, no significant correlation can be detected for the years 2011 and 2012. Despite an increase of the RES-E share from 20.5% to 22.9% (BMU (2013)), the correlation of the intraday prices to the local values in the considered grid area has remained the same (-0.10); for the day ahead prices a slight increased effect is detectable. With regard to the current situation, it can be concluded that steering signals by market prices are not appropriate (and to some extent even counterproductive) to solve local problems in distribution grids.

In a final step, the impact of a ‘cooperated’ operation of the storage asset is evaluated as described in Subsection 5.2.3.5. The cooperation of an energy trader and a grid operator may result in a usage of distributed storage assets for more than one purpose leading to a more efficient use. Hence, this operation is in contrast to a situation, where a trader exploits the economic value of peak prices but may force the grid operator to reinforce grid assets to enable the resulting profiles. As described in Subsection 5.2.3, this situation is modeled by optimizing the profit with equation (5-9) and integrating the constraint of (5-8). In the concrete case, the maximum peak is fixed with TP=6.43 MW, meaning that the storage potential is used for grid purposes to reduce the peak as much as possible. The results for the calculations are given in Table 5-4. The maximum transport in a time interval is depicted to reveal the resulting effect (e.g. a decrease of the peak by 38% from 10.29 MW to 6.43 MW in the day ahead scenario), but the results in the table show that adding the grid objective has only a minor effect on the annual reduction of the profits. Furthermore, the high correlation coefficients to the basic scenario are shown with values above 0.99 for both scenarios c)* and d)* compared with the scenarios without considering grid constraints (scenario c) and d), respectively).

Table 5-3: Correlation coefficients of local transport values and day ahead / intraday prices

$r_{X,Y}$ in the year 2011	day ahead prices	intraday prices	shares of RES-E 2011
local transport values	-0.05	-0.10	20.5%
$r_{X,Y}$ in the year 2012	day ahead prices	intraday prices	shares of RES-E 2012
local transport values	-0.10	-0.10	22.9%

Table 5-4: Impact of grid constraints for the profit optimization

	scenario: c) → c)* day ahead price with grid constraint	scenario: d) → d)* intraday price with grid contraint
maximum transport [MW]	10.29 → 6.43	8.71 → 6.43
annual reduction of profits [€]	3,707	2,916
annual reduction of profits [%]	1.86%	1.28%
correlation coefficient to the 'basic' scenario without grid constraints	0.9956	0.9970

According to Table 5-4, the annual reduction in profits can be compared with the reinforcement costs of the grid operator (e.g. due to limited capacity of the 30/10-kV transformer) to enable the operation of the high peak in the price driven scenarios. The investments in this reinforcement are likely to be much higher by a few orders of magnitude and, thus, do not justify this investment from an overall economic point of view.

However, current market design still supports this situation since DSOs do not have the opportunity to intervene in the schedule of storage assets operated by energy traders. Currently, this is still a very seldom scenario, but with increased market penetration of the electricity generation out of renewable energy sources (RES-E), concepts to allow a more overall efficient usage of storage assets should be introduced.

5.2.5 Political implications

The presented results enable a discussion for an appropriate integration of the distributed storage assets with a corresponding market design, which is presented in this section. The achieved results of the previous section show that an 'uncontrolled' operation of distributed storage assets by energy traders has an influence on local grid problems - it does not reduce the need for reinforcements to integrated RES-E but it even may intensify this need. Nevertheless, there is a promising potential for a cooperation of the stakeholders, energy trader and DSO, since an intervention of the DSO may be needed seldom and therefore leads only to an acceptable reduction of profits, but has large effects on the investment costs for the DSO. Based on the described results, two main solutions are proposed for an efficient integration of storage assets. The discussion concentrates on the situation in Germany, but the conclusions are likely to be transferable to a lot of other industrial countries, since similar problems in distribution grids with an increased share of RES-E and similar price profiles may occur.

First of all, the operation of storage assets by DSOs should not be hindered in general by law since market mechanisms do not solve local grid problems. Instead, even an increase in transported peaks and thus, in the need for reinforcements is shown in Subsection 5.2.4. Currently, it is still in the debate whether grid operators may be allowed to buy and sell energy to operate the storage asset or not since the unbundled market design intends separate market roles for trading, generating, selling and distributing the energy. Basically, these assets should be attributed to trading parties since the operation of storage assets in the unbundled electricity market is faced with competition and not primarily part of the natural monopoly. However, in future scenarios of avoiding reinforcements with additional assets, storage assets may be more efficient for distribution system operators with positive effects for the remaining part of the supply chain (e.g. no feed-in peak in transmission grids). Hence, it would be economically reasonable to allow distribution system operators to invest in local storage capacity (instead of enlarge grid assets) and operate the local storage according to the technical requirements of the local distribution grid. On the one hand, the selling of energy by DSOs is already implemented in the current design since DSOs have to cover grid losses by calling for tenders for the supply of energy in a non-discriminatory manner. On the other hand, the trading of energy is not the objective of the grid operator when operating the storage assets. Thus, if the storage asset is implemented to avoid the conventional reinforcement and if this solution is more efficient with lower costs compared with conventional alternatives, it should not be hindered by the market design.

Secondly, if the storage stakeholder is a trading company, the incentive for considering grid restrictions may be implemented by the DSO itself. As described in Subsection 5.2.1 it is still in debate how the investments in local storage assets should be incentivized. An exemption of grid fees and taxes has been assumed for the arbitrage scenario. This incentive for the trading companies operating a storage asset should only be enabled if the DSO is allowed to intervene in the (re-)storing profile to avoid seldom, but high peaks. As shown in Subsection 5.2.4, a reasonable decrease in profits occurs going along with a significant decrease of the production peak. This proposal for the creation of incentives for investing in local storage assets contradicts with the ideas of the German regulation agency - in BNetzA (2011), it is stated that the agency assumes storage assets to be 'usual' appliances connected to the grid. Hence, the agency sees no reason for reduced or exempted grid fees. This position reveals the unclear situation for the incentivizing of investments in storages assets. As shown in the results and within this discussion, we only agree with this statement in case of uncontrolled operation of the storage asset. In the case of considering grid constraints with the possible result of avoided or delayed reinforcements, the exemption of grid fees seems to be an appropriate incentive for the storage stakeholder with positive effects on low grid costs.

As an example of a practical, but unfortunately counterproductive solution, the legal regulations of Germany are analyzed. The German law (§14a EnWG (2012)) allows only a reduction of the grid fees for interruptible consuming devices in the low voltage level (1-kV). The management of the grid operator to achieve a relief to the network has to be 'reasonable' for the consumer and thus, it is restricted to relatively seldom situations. With regard to the current law, the modeled storage assets are not included since devices connected to the medium voltage levels (such as 10-kV) have not been considered in the law. According to §19 StromNEV (2011), consumers are incited for an asynchronous consumption pattern by reduced grid fees. In this case, the relief can be granted if the maximum load of this consuming device occurs foreseeable and to a significant extent in other times than the (remaining) maximum load in the grid. With respect to the impact on the situations in rural distribution grids with lots of RES-E, a counterproductive effect can attune - if prices are high (indicating high consumption with low generation on a global market place, e.g. nationwide or on a European level), the storage stakeholder is incited to withdraw the energy from the storage asset. The 'consumption' of energy (storing) is shifted to times with low prices. As proven in the previous sections, this may cause additional problems in rural areas with lots of RES-E since the withdrawal can occur in times with lots of (local) PV contribution. Thus, this legislative regulation may even provide counterproductive incentives for an efficient integration of distributed storage assets in certain distribution grids when local and global perspectives and steering signals are not aligned.

In practice and future 'smarter' energy markets, the required cooperation of different stakeholders could be achieved e.g. by forecasting, planning and real-time control of energy management of the grid operator and the trader as presented in Subsection 5.3.2 and discussed shortly in Subsection 5.2.1. A practical approach to enable the cooperation is the implementation of the traffic light system discussed in Subsection 4.5.2. However, further research tackling the challenge of appropriate cooperation mechanisms in the electricity supply chain is to be left for future work.

In general, storage assets are likely to play an important role in future electricity supply chains. Next to peak shaving and arbitrage also providing ancillary services and short-term balancing (i.e. in regard to frequency deviations) are interesting playing fields in the future, if economically feasible. This applies also to the introduction of storage assets in islanded grids when integrating fluctuating RES-E.

To exploit the potential of storage assets in grids in industrial countries with lots of stakeholders, changes in the market design are required as shown in this section. These adaptions should enable storage operation for different parts of the supply chain including a rational prioritization. Surely, other countries differ with regard to specific market structures, legal frameworks as well as the development of (renewable) generation and the structure of the load. Nevertheless, we expect that also in these countries at least similar developments resulting from similar climatic objectives will occur in the near future.

To investigate whether this challenge exists also for the exploitation of the flexibility of demand side management appliances or not, the next section deals with different steering methods and the impact on distribution grid planning for electric heat pumps.

5.3 Usage of the flexibility of electric heat pumps

As described in the former chapters, distribution system operators are faced with changing requirements on grid performance - a further important challenge is the connection and operation of new types of ‘controllable’ consumption devices. These new appliances include electric vehicles, electric heat pumps and ‘smart’ white goods - all suitable in various forms for demand side management (DSM). The implementation of DSM is one element in the framework of smart grids, which may help to increase the amount of RES-E and to stimulate efficient usage of grid assets.

Electric heat pumps experienced significant growth rates and have obtained a relevant share of heat supply systems. In Germany, the share of installations in new houses rose from 0.8% in 2000 up to 24.5% in 2012. This development was accompanied by a corresponding decrease of the market share for natural gas heat appliances (AGEB (2013). In the Netherlands, Gorinchem is an (and the first) area supplying all of the residential heat with heat pumps (Pruissen and Kamphuis (2010)). In Sweden and Switzerland, market penetration is even a lot higher, as described in Goetzler et al. (2009). The market share of ground-source heat pumps (GSHP) in new houses reaches 75% in Switzerland; in the Swedish renovation and modernization segment this value is even a bit higher. Also the USA as the world’s largest market for GSHP has experienced a substantial increased market penetration of GSHP (Goetzler et al. (2009)). Heat pumps can play an important role in smart grids in the future. Since they are often equipped with hot water tanks and connected to an inert floor heating system, the consumption of power demand for the pump can be shifted in time. This flexibility can avoid bottleneck situations in the grid and help improving the integration of fluctuating power generation - resulting especially from renewable energy sources. However, the steering of heat pumps using price signals can cause problems in local distribution grids since the assets of the distribution grid may not be dimensioned for large consumption peaks resulting from similar and synchronized behavior of the heat pumps caused by price steering signals.

In this section the integration of electric heat pumps is investigated focusing on the grid costs in the low voltage level up to the next transformer. For this, an optimization approach is combined with concrete measurements of smart meter data of heat pumps and households. More precisely, for a concrete development area the grid costs are investigated by dimensioning the network of that area for different design values per household. The used design value D_{max} is given by the maximum demand, which the grid operator takes into account for one connection point (household with heat pump). Hereby the grid operator assumes a non-synchronized consumption pattern with stochastic behavior in the supplied area. D_{max} is derived for three different cases which are

a) flattening the consumption profile (peak shaving),
b) the existing situation with static curtailing of the turn-off times of the heat pumps,
c) the cost reduction on consumer side by using (uniform) price signals in low price periods.

It is shown that grid costs differ depending on D_{max} and, thus, the optimization objective. The potentials for the cost reductions derived from these scenarios reveal conflicting interests. In the situation of peak shaving as the ‘grid friendly’ approach a cost reduction can be achieved for the grid operator and − with delay − for the consumer (‘indirect’ benefit, see e.g. Bauknecht (2011) and the explanations in Subsection 2.1.2 and in Chapter 6).

In the scenario of using price signals, the consumer can directly reduce the costs for the consumption by using low price periods on the electricity spot market. However, grid costs increase significantly since in this case larger D_{max} values are needed and lead to additional and stronger dimensioned grid assets.

The remainder of this section is organized as follows: in the next section a short overview on the current state of the development of heat pumps is given. In Subsection 5.3.2 the optimization approach and results from some basic simulations are presented. Subsection 5.3.3 contains the results of a smart meter project, which determines the current design principles in new grid areas of a specific distribution system operator. Furthermore, some statistical facts for the heat pump and household consumption are derived. These elaborations are used as basic input in Subsection 5.3.4, where simulations for grid planning and investment costs are presented to show the influence of the different optimization approaches. To obtain the results, a specific development area is embedded in a case study. The second part of this section presents a cost-benefit-analysis. The additional grid costs in case of optimizations on the consumer side are confronted with the (possible) cost reductions using periods with lower electricity prices. This welfare-economic view allows us to evaluate the potential of the full exploitation of DSM of heat pumps without considering grid restrictions. The results are derived for the specific, considered area, but the resulting trends for the costs and benefits are comparable in other electrified regions and countries. The analysis shows that the grid constraints should be taken into account to avoid an overcompensation of costs. This overcompensation is the case if additional grid costs exceed the cost reduction by DSM-operation and hence, welfare-economic undesired situations occur.

5.3.1 Related work

Heat pumps are seen as an essential element in the context of smart grids. Their functionality provides flexibility for grid operators, suppliers and consumers. Nevertheless, the (relatively high) connected load can lead to problems for grid assets. For the technology of heat pumps and their role in smart grids an abundant amount of literature exists. A heat pump consumes electricity to raise an operating medium (OM) from a lower to a higher temperature level. The OM changes the thermodynamic state within the process. In liquid form, it withdraws evaporation heat from the heat source and becomes gaseous. The pump compresses the OM so that temperature is raised and heat can be transmitted to the heating circuits. The OM liquefies during cooling and the cycle gets closed. The main used heat sources are soil (ground), air and water. Soil-water heat pumps extract the energy using horizontal collectors or geothermal probes. Air-water pumps work with the outside air and are therefore faced with more fluctuating temperatures in the heat source. The water-water heat pumps use the temperature of surface water and ground water. A more detailed description of the heat pump technology and current developments can be found in Chua et al. (2010), where also different studies are included to show fields of applications. Furthermore, Laue (2002) gives an overview on the history and ecological advantages of heat pumps.

In an energy hub model (Ahčin and Ŝikić (2010)) the heat pump is included as an active part within the energy network model. The focus of the energy hub model is on evaluating the profitability of heat load management on the consumer side. By considering changing spot market prices, the heat pump can be managed to avoid peak prices and instead operate in off-peak-periods. The simulations show a potential cost reduction of more than 10% for the consumer. Restrictions from the grid side are not considered. The analysis in Pruissen and Kamphuis (2010) focuses on the potential of smart control from the perspective of the grid operator. It is shown that a smart control can avoid exceeding the maximum permitted load values of the transformer in a substation in the distribution grid. The opposite is shown for uncontrolled scenarios in case of autonomous starts after a blackout. In this scenario, the operation of the heat pumps would lead to three times higher load values than permitted.

To analyze resulting grid costs with different optimization objectives, an approach developed at the University Twente is used. This method is described shortly in the next section.

5.3.2 Optimization potential and TRIANA

The potential of demand side management and its resulting energy streams can be analyzed and controlled using the three step optimization methodology TRIANA developed at the University of Twente (Molderink (2011), Bakker (2012) and Bosman (2012)). The approach consists of 1) offline local prediction of energy profiles, 2) offline global planning of energy streams and 3) online local scheduling of appliances in individual buildings (see Figure 5-5).

- Step 1: Forecasting: One of the advantages of the TRIANA approach is that it generates a planning, optimizing the energy consumption over a longer period in the future. This way, better results can be achieved compared to purely reactive systems (Claessen (2012)). Furthermore, still some flexibility for realtime reactions can be reserved. In order to generate a planning in advance, information about the future to determine the flexibility is needed. For example, to determine the possible runtimes of a heat pump, forecasts of the expected heat demand are needed. The information required for each individual device to generate a forecast is very device specific, and requires different kinds of data. However, generally a forecast is generated based on historical (usage) data and external factors like, e.g. weather data. The forecasts are improved continuously by, for example, learning the relations of weather and type of day (work day, weekend). For each device considered, forecasts are generated, which are used in the planning phase. The expected energy profile and possibilities to change this profile, i.e. the scheduling freedom, are forecasted e.g. 24 hours ahead. This step is performed locally (see for more details Bakker (2012)).

- Step 2: Planning: During operation, the controller will make decisions on when to switch on/off appliances, based on the current situation and what is the best option, given the planning. The planning is used to generate the optimal dispatch for each appliance, given a certain objective (for example, maximize the self-consumption of local generation or peak shaving). In the TRIANA approach, each device is responsible for creating a planning and requires a planning routine, which considers the current state, forecasts, device constraints and a steering vector to generate an optimal dispatch (see details in Bosman (2012)). The steering vector contains values describing how desirable energy production/consumption is for each time interval. The output of this planning is an energy profile. For each device, an energy profile is chosen such that the combined energy profile matches best the objective. Hence, in this step, the forecasted scheduling freedom is used by a (central) planner to exploit the optimization potential and to work towards an (global) objective. The planning can be done in a hierarchical way and hence, a tree structure with different branches and leaves can be used to describe figuratively the approach. By this structure, forecasting errors and computational times can be reduced and a better performing with respect to reaching the global objective is achieved.
- Step 3: Real-time control: The real-time control step is the end responsible process for actually steering the appliance. Its goal is to stick to the planning as good as possible, given the current situation, forecast errors and most importantly, the user comfort. The control loop is triggered by events, e.g. a user presses a button on a device, a timer event or a request from a global instance. One of the requirements of a control system is that it should be able to cope with a large set of different appliances. Therefore, there must be a generic interface to control an appliance, which is applicable and suitable for all kinds of appliances. Most control methodologies use the concept of cost functions. A cost function expresses the constraints and preferences of an appliance. At a certain point of time, it describes

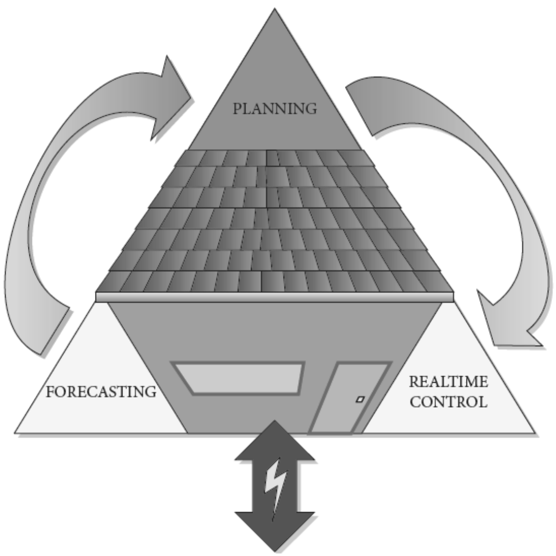


Figure 5-5: The three steps of TRIANA

the possible options an appliance offers for what (virtual) costs. For example, a freezer might generate a cost function with two options: switch on or switch off, where the preferred option is to switch on, when the internal temperature is close to the allowed upper bound and to switch off, when the internal temperature is close to the allowed lower bound. When a decision has to be made, the controller requests the set of options from all appliances. Via an optimization approach the real-time controller choses the best option for each appliance. These options are communicated back to the individual devices. The provided cost functions already include the preferences of the planner, and therefore the optimization problem can be solved very fast ensuring a responsive control system (see Molderink (2011) for details).

The control strategy TRIANA is flexible in the optimization objective and works in a generic way. The effects of the optimization methodology have been modeled and verified with a simulator (Bakker (2010b)).

The TRIANA approach has been extended to integrate the heat pump with its technical characteristics (Toersche et al. (2012)). As the objective for the optimization within the planning step peak shaving is chosen. Furthermore, a use case with 100 houses is considered and the results of simulations show a significant decrease in peak consumption by using TRIANA. The peaks decrease by 25% and the variation of the load by 33%. The impact of the steering mechanism is shown in Figure 5-6. The load curve visualizes the decreased peak and the more uniform distribution of demand and the flattened profile. This effect is visible in the hours with low demand too. Without steering signals, certain time periods have no demand – the potential of heat pumps for shifting demand is unused.

5.3.3 Smart meter project

In this subsection some results of a smart meter project are given. The obtained metering data allows further analysis of the consumption of households and heat pumps. In addition to the control methodology described in the previous section, these realistic data are relevant parameters for the case study in Subsection 5.3.4.

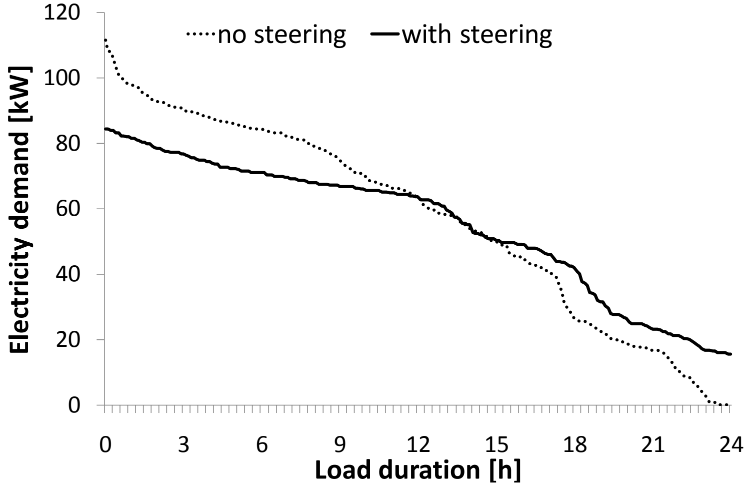


Figure 5-6: Optimization of heat pumps (peak shaving)

For a group of 10 new houses in the region of Neuenhaus, Germany, 20 smart meters were installed, each measuring the electric consumption of the heat pump and (rest of the) household separately. This pilot project was conducted to test a specific kind of smart meter technology and analyze data of (new) households and soil-water heat pumps. Furthermore, weather data of a nearby weather station is available. The smart meter data was measured and transmitted at a 15 minutes interval, the weather data with 10 minutes intervals. The duration of the project was eight weeks in a winter with a minimum measured outside temperature of -8.0 °C. The heat pumps are equipped with a separate meter since it is the intention to use the heat pump as an adjustable consuming device. The grid operator is authorized by contract to switch off the heat pump in case of (other) high consumption peaks in the grid to avoid overload. In particular, the turn-off times of the heat pumps are determined such that it can reduce or even avoid an increase of the consumption peak per household due to the use of heat pumps. During peak times when the pumps are switched off, all heat demand should be supplied using the heat buffer. This hot water tank in combination with a slow response floor heating system avoids loss in the comfort for the consumer. This installation setup was realized in all of the 10 houses, whereby the heat buffer was typically dimensioned at 200 up to 300 liters. Currently, the demand of the heat pumps is statically curtailed for two hours at noon. The turn-off time is based on historically measured values of household peaks and can be changed, e.g. to three times per day for one hour.

The houses are heterogeneous and highly insulated considering currently implemented standards that are prescribed by the German law (EnEV (2012)). The heat pumps have a maximum power demand of 2 to 5 kVA. The minimal allowed efficiency for heat pumps is regulated by law too (EEWärmeG (2011)) - for soil-water heat pumps in new houses with hot water heating the annual coefficient of performance (aCOP or seasonal performance factor, see for more detail (Lund et al. (2009)) has to be at minimum 3.8. The normal market standards according to manufacturers' data are between 4 and 5. In Chaiwongsa and Wongwises (2008), even a COP of 6 has been evidenced.[29] In addition to the heat pump, houses have an auxiliary heating rod of 5 to 10 kVA ('COP' < 1).

Using the heating rod for supplying all heat demand is prohibitively expensive for the customer. Furthermore, it can cause grid problems when all houses operate at the same time the heating rod. The heating rod is therefore exclusively enabled as a backup in case the heat pump system is malfunctioning. In the measurement data, this occurred for one day at one house (causing approximately 15 € in electricity consumption for the household). It is essential that the diversity factor (defined as the quotient of the actual used and the installed capacity) of the heating rod is very low, i.e. nearly all houses must not rely on it to avoid overload of the grid assets. To exclude the working of the heating rod (and the high costs), six of the ten households even disconnected the heating rod without having problems in winter due to the high insulation standards.

In the chosen grid area, the network is planned with a design value D_{max} for a house (including heat pump) of 3.5 kVA each. This value is based on the consideration that not all heat pumps and households consume electricity at the same time with their maximum connected load. Moreover, the experiences gained from other areas regarding the different used heat sources are incorporated. Consumers use alternatively natural gas appliances

[29] It has to be clarified, that the maximum COP is a kind of 'snapshot'. The value massively depends on the temperature of the heat source and the water in the heating cycle (heat sink). Thus, the COP has to be described with underlying parameters (temperature level) or to be oriented to an appropriate period of time (e.g. one year).

(more and more with support of solar collectors for the hot water production), district heating with biomass combustion or wood pellet heating (AGEB (2013)). This development goes along with legal requirements - in Germany (as the measured data are determined from here), the usage of a renewable heat sources for heat supply in new houses is prescribed per law (EEWärmeG (2011)).

Summarizing, it can be stated that the design demand of 3.5 kVA is based on historical measured and calculated values. This value has increased over the years considering the increasing power demand of households and the increasing installation of heat pumps. However, a complete supply of heat in an area with only heat pumps operating has not been taken into account yet.

To give a first impression on the measured data, the load curve of the demand for electricity for the average heat pump and household is visualized in Figure 5-7. For one specific day in winter with temperatures going down to -8°C, the curves show the average demands of the heat pumps (HP) and the separately measured remaining appliances of the household (AHH) as well as the sum of both values. Note that the chosen day is the day with the maximum measured load value of 3.74 kVA since the grid has to be designed for this worst case. The load curve of HP is most of the time above the load curve of AHH. Exceptions are hours in the evening (due to increased household consumption) and noon (due to turn-off time of the heat pump). As described earlier, the turn-off time in these midday hours is based on historical consumption patterns. As can be seen in this figure, the peak of AHH is significantly more pronounced in the evening. This tendency is confirmed by the measurement of the other days in this winter time considered. The visualized day on the one hand shows the general trends and, on the other hand, contains the only time within the complete measured period where the aggregated load curve exceeded the 3.5 kVA line.

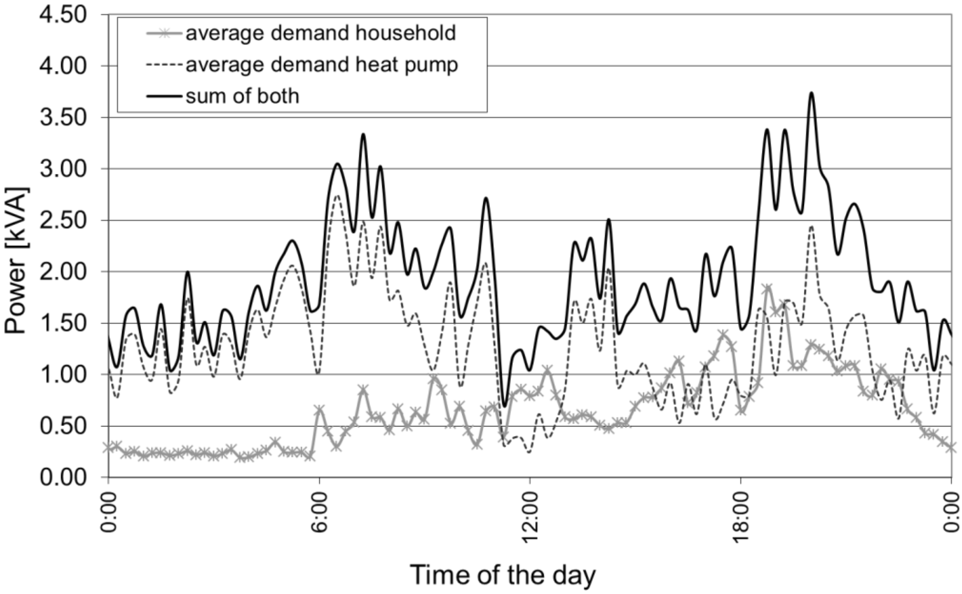


Figure 5-7: Smart meter results with highest load values

The exceeding of this currently defined design value is measured at 8 p.m. with a temperature of -0.2 °C. Since grid structures have to be built for the worst-case scenario, the maximum value has to be considered when determining the design value for the consumption of households with heat pumps.

Besides the visualization of HP and AHH the analysis to reveal more statistical correlations can be deepened within the data set of the complete measured period. It is shown that the line for HP decreases in process of time. This effect results from the increasing outdoor temperature. The correlation coefficient *r* between HP (*X*) and outdoor temperature T (*Y*) is calculated. For the data set, we get $r_{X,Y}$ = -0.534. The strong negative correlation was to be expected since an increase of T leads to fewer requirements for heat and therefore to a lower demand of heat pump power. If the correlation coefficient would reach a value of -1.0, a perfect negative correlation would be shown. This value is in real life unrealistic due to inertia of the heat pump system and connected buffer capacities as well as influences in consumption behavior.

Furthermore, the correlation between the demand of households and heat pumps is analyzed. It is preferable that this value is negative as well to prevent a situation where the peaks in demand intensify each other. With a positive correlation coefficient the heat pump would not behave ‘grid friendly’. In this case, the peaks in the consumption pattern would even become larger since peaks of household and heat pump behave additive. The correlation coefficient *r* between heat pump demand *X* and demand of household *Y* is calculated leading to $r_{X,Y}$ = -0.018. This indicates that no statistical dependence is detectable. In addition, a view on the load curves shows the necessity of changing the turn-off times since the peaks in the households curve appear mainly in the evening hours and, thus, the turn-off time of the heat pump should be changed to this period to reduce instead of increase the consumption peaks. This improvement should become visible by a more pronounced negative value of the correlation coefficient. The design value in grids can be left unchanged even if – as assumed in the case study – a penetration of 100% heat pumps as heat supply system for the households is reached. The consumers would not be affected by changed turn-off times since comfort would not be sacrificed due to the (time-modified) usage of the existing buffer capacities and the inertia of floor heating.

For new houses in the considered grid, the design value is still projected with 3.5 kVA, based on better interior insulation (decreasing heat and therefore also electricity demand). Furthermore, the turn-off time in new areas has been changed to be effective in gradual form and including especially the evening hours now. This result was the first consequence of the analyzed measurements. The correlation coefficients gave further information supporting the decisions. For the further analysis, this scenario with the current design value is defined as ‘state of the art’. A more smart and dynamic approach of steering heat pumps will need to be implemented in the future.

Considering the connected loads and the current design value, the need of a balanced control becomes visible - the average nominal capacity of the connected heat pumps amounts to 3.95 kVA and the maximum household peak was measured at 1.94 kVA per household. This sum of 5.9 kVA is the ‘worst case’ design value since it is the highest value, which might occur. Note that this excludes the power of the heating rod since almost all houses disconnect this appliance nowadays. The value of 5.9 kVA is much higher than the measured results and derived values for the optimized integration of heat pumps. It has to be considered as the design value D_{max} in case of price steering due to the same reactions on price signals (see, for example Gwisdorf et al. (2010b) for an analysis of the diversity factor of adjustable devices). At a large scale, this increase results in excessive infrastructure investment and higher maintenance costs. The increased capacities are only used when all houses and heat pumps simultaneously reach their maximum value. However, this is rarely the case and leads to inefficient usage of the (in the rest of the year) oversized grid assets.

In contrast and as mentioned in Subsection 5.3.2 a peak reduction of 25% can be achieved using the control approach TRIANA. Combining this with the measured data, this would lead to a decreased design value of 3.0 kVA (for households with heat pumps). Hence, this value is used as the design value D_{max} for the scenario of grid optimal introduction of heat pumps.

Both values, the 3.0 kVA for optimal integration and the 5.9 kVA for the ‘worst case’, are considered in the case study in the next section. In detail, the theoretical and practical results of this and the previous subsection are included in a calculation of the grid costs for various scenarios. The purpose of this case study is to identify how different steering methods and objectives for heat pumps affect the investment costs in the distribution grid.

5.3.4 Local effects of exploiting the flexibility

The case study presented in this subsection is divided into two parts. In the first part, the effects of different values for D_{max} on the network planning are shown. The measured data (Section 5.3.3) can be combined with the values from the simulations in Subsection 5.3.2. The different values for D_{max} lead to different investment costs for the exploitation of an area with electricity. The second part includes a short estimation of the cost-benefit-ratio for using the full potential of demand side management of the heat pumps without considering grid constraints.

5.3.4.1 Scenarios for grid dimensioning

The case study analyses grid costs in an area, where all residential heat will be supplied with heat pumps. Since the measurement data originates from soil-water heat pumps, we assume this technology to provide all heat for the households. If another heat source would supply all of the heat (e.g. air-water heat pumps), a changed value for D_{max} may be possible due to other operating modes and power demands. Nevertheless, the trends in grid costs for the different scenarios should be comparable.

The difference of the design value of houses with heat pumps has massive impact on the number and dimensioning of grid assets (e.g. cables, transformers). For the various scenarios, the investment costs for supplying the area with electricity are evaluated. Hereby, the investment costs reflect the annual capital expenditures (CAPEX) as an important part of the costs of grid operators (for more details see Mountain and Littlechild (2010 and further elaborations in the remainder of this section). It can be distinguished between new and existing areas since especially costs for underground digging are much higher in existing areas with tarred or paved surfaces (e.g. roads).

The main restrictions in the planning process of distribution grids are a) stress of assets (current passing the grid assets)) and b) voltage values as explained in Section 2.2. Each asset has an individual value for permissible stress – e.g. for cables and transformers maximum power transfer is restricted by asset specific current values (ampacity). Furthermore, a higher load can cause the voltage to fall below the minimum permitted voltage of public supply. These limits are determined in the European norm EN 50160 (2010). The most important is the voltage magnitude variation requiring a supply within ± 10% of the nominal voltage (for details, see Subsection 2.2).

Considering these restrictions the electricity supply for an example area with 102 households is planned. In the chosen area the first house was built in 2010, and in the meantime, the first houses have been connected to the grid, so realistic and up to date values for the investments, the possible routes for cables and positions for transformers are available. In the current network planning, one substation is intended to supply the area. The connected low voltage cables are operating as three-phase current cables with 400 V, the medium voltage cables connected to the transformer work with 10 kV. The network planning and calculation for voltage and stress values is made with proprietary programs used by grid operators. This applies for the estimation of the costs for the investments as well.

As mentioned in the previous sections, the effects of three different design values for a connection point (household including heat pump) considering the diversity factor are investigated leading to four scenarios:

(a) D_{max} = 3.0 kVA; this value is possible if grid-oriented optimization of the use of heat pumps is applied (peak shaving).

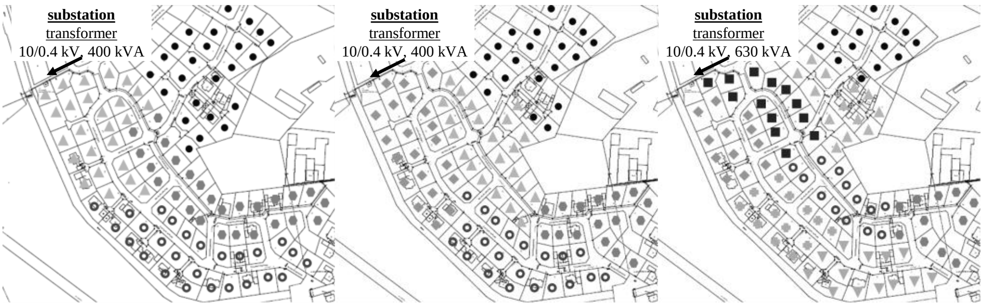
(b) D_{max} = 3.5 kVA; this value is possible with changed turn-off times of heat pumps, but no further control (‘state of the art’).

(c) D_{max} = 5.9 kVA; worst case scenario if all heat pumps consume electricity simultaneously with the nominal capacity as maximum possible load but without heating rod (e.g. based on price signals).

(d) like c (D_{max} = 5.9 kVA), but simulated in an already existing area, where the grid structure previously has not been dimensioned for this (relatively) large design value.

Note that the following derived results for the numbers of assets and, thus, for the investment costs depend substantially on the situation of the chosen supply area. However, the general approach and the elaborations apply also for other distribution grid areas. The differences in grid structures and in the number and dimension of assets for the considered area are shown in Figure 5-8. Thereby, the low voltage level is characterized by the different low voltage circuits supplying the area with each circuit having a limited capacity. Thus, a limited number of houses can be connected to a circuit. The allocation of households to the different low voltage circuits is visualized in Figure 5-8. The individual low voltage systems are illustrated with different symbols supplying the allocated houses. As expected a larger design value for a household leads to a smaller number of households per cable and therefore a larger number of circuits to supply the area with electricity.

In existing areas a further penetration of heat pumps can require an increase of the design value, so that grid assets must be adapted to the new situation. Historically, such a grid was not dimensioned for the high consumption peaks in all households. Moreover, in existing areas, the costs per meter of ditch are significantly higher compared with new areas as CAPEX increases with solid surfaces. These effects have to be considered in the costs calculation as well. Therefore, in this fourth scenario (d), new cables for the reinforcement have to be installed and connected to existing ones - the households have to be reallocated to the circuits due to the increased design value to avoid impermissible stress and voltage values. The allocation of households in this scenario (d) complies with scenario (c) in Figure 5-8.



(a) design value of 3.0 kVA per household (b) design value of 3.5 kVA per household (c) design value of 5.9 kVA per household

Figure 5-8: Allocation of houses depending on the design value

The resulting values for circuits, transformers, cables and ditches for the different scenarios are given in Table 5-5. Furthermore, the estimated costs of the different scenarios (CAPEX) are presented. For this, the costs are determined based on an investment planning considering the specific scenarios. The costs for the 'state of the art' exploitation (scenario (b)) are set as 100% and report the differences of the other scenarios to these costs.

One main result is that the number of power circuits increases with a larger design value D_{max} leading to increased number of cable-meters but hardly increased number of ditch-meter. This seems to be reasonable since the size of the supplied area as the main influencing factor of the length of ditches is not influenced. Regarding scenario (d) the length increases because of the new ditches which have to be dug next to the existing ones for the connection of new cables to the transformer and reallocation of households. Furthermore, the more solid surfaces raise the costs significantly.

It can be concluded that an optimal integration of heat pumps leads to a cost decrease of 10% in comparison to the state of the art. A full exploitation of DSM and therefore of maximum power of heat pumps leads to a massive cost increase. In new areas, this investment is 22% higher than in the basic scenario; in existing areas this value rises up to 71%.

5.3.4.2 Cost-Benefit Ratio

In the following an initial estimation on the cost-benefit ratio is being set up. This ratio visualizes the relation between increased investment costs for the grid and the attributed cost reductions on the consumer side. The direct attribution is possible since the reinforcements are only necessary to allow the full exploitation of demand side management of heat pumps.

Table 5-5: Costs and asset numbers for the different scenarios

Results	a) peak shaving	b) state of the art	c) maximum DSM of HP in new areas	d) maximum DSM of HP in existing areas
design value per household [kVA]	3.0	3.5	5.9	5.9
power circuits [number]	4	5	8	8
size of transformer [kVA]	400	400	630	630
meters of cable [m]	2,315	2,765	3,735	3,800
meters of ditch [m]	1,575	1,685	1,715	2,340
CAPEX [%]	**90**	**100**	**122**	**171**

First, the economic benefit is illustrated by calculating the payback period. Thus, the main question is if and when the additional investments costs are amortized by the annual cost reductions. This welfare-economic approach opposes the CAPEX on grid side with the cost reductions on the consumer side. The increased CAPEX will result in higher grid fees for the consumers, so the economic calculation should show positive results in the interest of all market participants. To calculate the consumer benefits, the following parameters are used:

- number of relevant heat pumps: n=102
- saved electricity costs for the consumer per kWh: p=-3 ct/kWh[30]
- duration of the consumption peaks in the grid due to low price phases : t=200 h/year
- available heat pump power (each): P=2 kW.

These parameters are verified with the spot market prices for electricity in Germany. In 2010, the average hourly price on the EPEX auction market (day ahead) is given by 4.449 ct/kWh. 257 hours can be found with a price at least 3 ct/kWh below the average value. In 68 hours, an hourly price at least 4 ct/kWh below the average value was detectable. In 12 hours in 2010, even negative prices are given. Since the heat pump only works reasonably in cases of demand for heat or cooling, the assumptions seem to be comprehensible. Using the above parameters, the sum C of the cost reductions on consumer side can be calculated:

$$C = p \cdot t \cdot n \cdot P = 3\frac{\text{ct}}{\text{kWh}} \cdot 200\frac{\text{h}}{\text{year}} \cdot 102 \cdot 2\text{kW} = 1{,}224\frac{€}{\text{year}}$$

Comparing this annual benefit with the needed additional costs for the investments (scenario (c) and (d)), the (welfare-economic) payback period can be calculated. For this, we assume an interest rate of 6%/year to cover costs for financing and for considering risks for investments. The cost savings start in the year 1 following on the investment in the year 0 and are given in Table 5-6. For scenario (c) a payback period of 68 years for the additional investments is calculated. In scenario (d) (high investments due to reinforcement and more expensive surfaces) a payback period is not even achieved.

In the above calculations, the fact is neglected that the heat pumps are installed gradually in the area and that increased grid costs may occur on higher voltage levels too. This more realistic view would even increase the payback period. Furthermore, it should be mentioned that, currently, the reaction of consumption devices on price signals or on grid requirements to lower the load is not enabled on a large scale, which is mainly caused by the lack of smart meters, suitable products and appropriate information and communication

Table 5-6: Calculation of payback period

year of cost saving	annual amount (discounted) [€]	cumulated amount [€]
1	1,155	1,155
2	1,089	2,244
3	1,028	3,272
4	970	4,241
5	915	5,156
…	…	…

[30] It has to be noticed, that the fixed parts of the electricity price for the consumer remain (such as taxes).

Table 5-7: Summary of the economic calculations

	scenario (c), new area	scenario (d), existing area
payback period [years]	68	not defined
cost-benefit-ratio	1.1	3.6

technologies. The exploitation of this potential in the context of smart grids is an important task for the future and, thus, also a political objective (see Chapter 1 and 2).

To show the effects described above and in Table 5-6 in an alternative way, the cost-benefit ratio for scenario (c) and (d) is calculated. If the investment is reasonable from a welfare-economic point of view, the benefit should outweigh the costs and thus, the ratio should be smaller than 1. To calculate the ratio, the annual costs (annuity) for the investment costs have to be determined. With the given investment, the interest rate and the lifetime of the grid assets, it is possible to calculate the CAPEX as annual costs. In this use case, for the low voltage cable a lifetime of 40 years is assumed as a typical value for this kind of asset (see for example StromNEV (2011)). Note that the European Commission determines even only 20-30 years as a commonly used value for the deprecation of energy infrastructures (EC (2008)). Considering these values, the cost-benefit ratio would even be larger (and, thus, worse from an economic point of view).

For the cost-benefit-ratio the CAPEX as annual costs are compared with the annual cost savings on the consumer side. For scenario (c) we get a cost-benefit-ratio of 1.10. For scenario (d) this ratio increases up to 3.60. Especially in the latter case, the costs substantially outweigh the benefits. A summary of the economic calculations from a welfare point of view is given in Table 5-7.

The above calculations do not dispute the profitability of demand side management – the meaningfulness should not be questioned at all either. Instead, grid load management in the context of controllable appliances is shown to be required in future energy systems. Otherwise, the risk exists that cost reductions with DSM, e.g. achieved by reacting on uniform price signals, are overcompensated by massive higher CAPEX costs for the grid investments, which are required to cope with the peaks in the consumption profiles. Costs and benefit may differ in other areas, but based on the specific use case analyzed in this section, the importance of an integrated view on the power system is illustrated. In other words, assuming a copperplate scenario in distribution grids may cause unreasonable high costs and hence, real grid constraints need to be taken into account. Additional DSM-technologies will strengthen this need for grid control since especially electric vehicles have much higher connected loads than heat pumps and can cause therefore even larger grid problems. Accordingly, IEA (2011) states that charging of electric vehicles needs to be managed intelligently to avoid an increase of the consumption peak, major infrastructure investments in grids and - as a worst case - supply failure.

5.4 Conclusions

In this chapter some examples for the required interaction of stakeholders in the future electricity supply chain are analyzed. Hereby, the focus is on the cooperation or individual optimization of distribution system operators as a part of the regulated business and energy traders (retailer) representing the competitive part of the supply chain.

First, the expected profiles of the operation of distributed storage assets are derived, depending on the stakeholder operating the asset. For this, a situation is analyzed with real world data for the consumption and production in a distribution grid area (30-kV) in Germany with a basic scenario without introducing a storage asset (scenario a)). This area is faced with a lot of renewable energy generation (especially photovoltaic). For the considered area, the operation of a locally installed storage capacity (2 MW / 8 MWh) in this grid is simulated with a number of different optimization objectives. In scenario b) the storage is used to minimize the peak transported upstream to the 30-kV grid. For the other two scenarios, the storage asset is assumed to be operated by a trading company, aiming to maximize its profit by using prices spreads (arbitrage). For this, German day ahead prices are used (scenario c)) as well as intraday prices (scenario d)). The analysis shows substantial differences between the scenarios, especially with regard to the transported peak via the 30/10-kV transformer. Whilst in the scenario of peak shaving the storage is fully exploited to decrease the transported peak, the arbitrage scenarios reveal in the worst case that the maximum peak is increased significantly compared to the scenario without storage. In the scenario c), the maximum peak even increased with +93% of the power of the storage device compared to the basic scenario a), so that extra grid reinforcement is needed. Although the effect of an increase of peaks occurs very seldom, the grid has to take these peaks into account. Thus, undesired situations occur from an economical point of view, since the costs for the grid reinforcements (passed with delay to the consumers) substantially exceed the arbitrage profits for these seldom time periods. For an operation oriented on arbitrage but considering the grid constraints, the peaks in the use case are reduced from 10.29 MW to 6.43 MW (-37.5%) for the day-ahead simulations (-26.7% for the intraday data scenario) with an decrease of the profits gained at the spotmarket by -1.86% (-1.28%, respectively). Following these observations, a proposal is presented to cope with this problem by 1) enabling a DSO to integrate storage assets for own purposes and 2) incentivize trading companies for an integration of storage assets by reduced or exempted grid fees providing that the grid operator is allowed to use the storage for grid congestions in seldom, but critical situations.

In the second part, the effects of different steering methods for heat pumps on distribution grid structures are investigated. Two main scenarios (peak shaving and demand side management (DSM) oriented on uniform price signals in low-price periods at the energy spotmarket) are analyzed. The results considering measured smart meter values show different design values for the specific scenarios. Hereby, the design value characterizes the power considered for a connection of a household with heat pump, whereby the diversity factor is taken into account. As it is shown in the study, varying investment costs for the distribution grid occur. The scenarios of 1) optimal integration from a DSO perspective with peak shaving, 2) the current measured situation and 3) maximum exploitation of DSM potential and, thus, synchronized reaction on price signals, are compared in a case study. The decrease as well as the increase in grid costs is quantified depending on the optimization objective. The results of the case study show that a full exploitation of DSM potential only based on price signals leads to extra costs on the grid side for additional and stronger dimensioned assets to cope with the consumption peaks of heat pumps. These costs can exceed the cost reduction on the consumer side enabled by using lower prices for the operation of the heat pumps. As a consequence, grid restrictions should be considered in smart grids to avoid welfare-economic unreasonable situations with overcompensation of costs in grids resulting from DSM. The simulations show that a decrease in local grid costs of 10% is possible if the optimization objective is oriented towards peak shaving.

The optimization approaches for using the flexibility of storage assets and DSM devices play a key role in the context of smart grids to reach global objectives with acceptable costs. Thereby, and as shown in this chapter, local grid constraints need to be taken into account. In the next chapter it is analyzed whether there are generally incentives for grid operators or not to invest in innovative concepts such as storage assets and the implementation of demand side management.

6 Regulation of smart grids

Abstract - *The connection and distribution of growing, decentralized electricity generation from renewable energy sources (RES-E) is leading to massive investment needs in grids as shown in the previous chapters. Besides investing in additional 'conventional' assets (e.g. cables), grid operators can also invest in innovative 'smart solutions' like local storage capacities or voltage regulation appliances, which may be a more suitable way of integrating RES-E. The investments are required to enable the energy transition - the research presented in the previous chapter focused on a 'macro'-perspective showing that this transition affects interactions and business models of the stakeholders in the complete power supply chain. However, also the isolated view on single stakeholders ('micro'-perspective) is important and should indicate incentives for the participation of the stakeholders in the transition process. This perspective is chosen in this chapter focusing on the regulation of distribution grids.*

More precisely, the influence of incentive regulation on the investment decision of grid operators to integrate RES-E is analyzed. The relevant technical and regulatory background is briefly described and an approach is presented to compare investment scenarios under the revenue cap regulation. The approach considers the special context grid operators are operating in. As an example, in a case study considering the German electricity regulation regime the profitability of investments is calculated. For this, Data Envelopment Analysis (DEA) and Stochastic Frontier Analysis (SFA) are applied to show the influence of the investment alternatives on the grid operator's efficiency objectives. It is demonstrated that under current 'standard' incentive regulation, the grid operators gain profitability by avoiding investments and - if they are forced to invest - by not implementing 'smart solutions', but invest in conventional reinforcements. The presented results highlight the need to consider innovation in the regulation design. Further research should investigate specific instruments that can be used to account for innovation. The brief discussion on political implications may be a starting point of creating such instruments.[31]

6.1 Introduction

The aim of this section is to investigate the influence of incentive regulation on the investment decisions of distribution system operators (DSOs) to integrate RES-E. It is analyzed whether there are incentives or disincentives for investments in innovation under 'standard' incentive regulation[32] or not. Furthermore, factors influencing the profitability of grid investments are quantified to determine the incentives to invest. The focus in this chapter is on the perspective of DSOs due to their central role in the power supply chain and in the transition process. This isolated view makes it possible to answer the question

[31] Parts of this chapter are from [Ny:1].

[32] For the remainder of this chapter, incentive regulation systems which do not take innovation into account, are referred to as 'standard' incentive regulation.

whether or not DSOs are given an incentive by the regulatory framework to participate in the energy transition and even further accelerate the process with innovations. As Germany is one of the major markets for the RES-E development in Europe, the focus in this chapter is on the German regulation system. Nevertheless, the main findings should generally be valid for comparable 'standard' incentive regulation systems and for countries with similar developments with regard to the integration of RES-E.

The chapter is organized as follows. Firstly, the relevant technical and regulatory backgrounds are briefly described. In Section 6.3, an approach is presented for calculating the profitability of investments under 'standard' incentive regulation. In Section 6.4, this approach is applied to a case study based on the German electricity system. For this purpose, Data Envelopment Analysis (DEA) and Stochastic Frontier Analysis (SFA) are considered, in order to demonstrate the influence of investment options on the efficiency values of DSOs, normally determined by regulatory authorities. The derived efficiency objectives are incorporated into the revenue cap of the grid operators and used in the profitability calculation. This approach enables an economic evaluation of the strategic options of grid operators to integrate RES-E. The results of these calculations are presented in Section 6.4 as well. In Section 6.5, innovation in regulation is discussed and some proposals for improving regulation methods to allow for a better incorporation of RES-E are provided. Section 6.6 concludes with a summary of the results and directions for further research.

6.2 Background - Regulation and innovation

In this section, first the technical aspects relevant for this chapter are described. The second part deals with the regulatory framework in general, whereby Subsection 6.2.3 provides more details on regulatory mechanisms by analyzing the German revenue cap regulation.

6.2.1 Smart solutions to integrate RES-E

As presented in Section 2.2, alternatives to conventional reinforcements to integrate RES-E are needed and emerge in various alternatives. In this thesis, 'smart solutions' are defined as reinforcements with new types of appliances and the usage of information and communication technologies (ICT) that integrate RES-E and avoid conventional grid expansion. Furthermore, some solutions such as introducing storage assets or implementing appropriate demand side management techniques provide also 'peak shaving' not only for the relevant grid operator but also for the complete technical system with positive effects for transmission grid operators and reduced needs for back-up power plants. Furthermore, the introduction of such technologies leads to a more efficient technical use of grid assets, since a better usage of these assets is enabled and seldom peaks are leveled out. A more detailed description of these technologies, technical advantages and economic challenges can be found in Section 2.2 for an overview and in Section 4.2 with a focus on decentralized storage systems.

From a technical point of view, the use of smart solutions is in many cases preferable to conventional investments. However, smart solutions are economically preferable, only if the additional investment costs are compensated for by lower long-term and overall costs. The grid operator's investment decision in how to integrate RES-E is fundamentally affected by the prevailing regulation method. In the next subsection, an overview on the literature focusing on the investment decisions in regulated sectors is given. Hereby, special interest is on innovations in the context of smart grids. In most European countries, an incentive regulation is applied (CEER (2011), Lapillonne and Brizard (2013)). Hence, it is of interest to investigate whether incentive regulation includes (dis-)incentives to innovate.

6.2.2 Regulation, investment and innovation

The concept of incentive regulation is described generally in Subsection 2.1.3. In this subsection, the influence of this regulation approach on investment decisions and incentives to innovate is investigated in detail to provide an understanding for the further analyses. Later on in this section, the elaborations have a focus on the German revenue cap regulation whereby this kind of regulation is a commonly implemented subtype of the incentive regulation.

Biglaiser and Riordan (2000) show that the regulation methods, as well as the length of the regulation period, influence the timing of investment and the investment activity. Armstrong and Sappington (2007) point out that incentive regulation provides strong incentives for cost reduction and thus for investments which reduce costs in the short run. By contrast, rate-of-return regulation only provides limited incentives for cost reduction. However, the incentives for durable sunk investment are stronger under rate-of-return regulation, because the grid operator is ensured a reasonable opportunity to earn the authorized return on investment over the long term. Additionally, uncertainty, caused by unpredictable regulation, for example leads to underinvestment (cf. Dixit (1989), Dixit and Pindyck (1994), Dobbs (2004a) and Dobbs (2004b)). Guthrie (2006) argues that under incentive regulation (in contrast to rate-of-return regulation), shareholders bear more of the investment risk, which discourages investment. Similarly, Maeding (2009) describes that the strategy of avoiding investments is risk dominant and preferable for regulated companies. Guthrie (2006) further concludes that the impact of regulation on investment depend on the particular industry. The potential problem of underinvestment is generally well-known and there is a literature on tackling this problem. To avoid underinvestment, regulators should apply so-called quality regulation (see, among others, Ajodhia and Hakvoort (2005), Giannakis et al. (2005), Joskow (2008) and Ter-Martirosyan and Kwoka (2010)). However, the question remains how a regulator should consider investments in innovations.

For a start, one can state that the theoretical analysis of incentives to innovate is complex, so that even in the absence of regulation, the relationship between industry structure and incentives to innovate is ambiguous (cf. Cohen and Levin (1989) and Armstrong and Sappington (2006)). However, it is unambiguous that competing firms have greater incentives to innovate than monopolies (see, among others, Arrow (1962)). The question of what incentives for innovation are provided by different regulation systems is discussed in several papers (see, for example, Smith (1974), Magat (1976), Cabral and Riordan (1989) and Clemenz (1991)). In accordance to Müller et al. (2011) it is distinguished between investments through replacement and those for expansion. Independent of this distinction, the corresponding costs are classified as capital expenditures (CAPEX). It is further distinguished between product and process innovation. While the costs of product innovations are also classified as CAPEX, those of process innovations are considered as operational expenditures (OPEX). In short, the literature concludes that incentive regulation, in comparison to other regulation methods, gives better incentives for investment and innovation with a short time horizon. These investments and innovations focus mainly on a reduction of OPEX. However, the effects of incentive regulation for investment and innovation with a long time horizon, and with a crucial impact on CAPEX, are ambiguous. The following discussion focuses on the effects on product innovation within an incentive regulation regime.

In general, it is well known that the regulatory time lag between cost reduction and the regulatory adjustment (e.g. revenue cap adjustment) is of major relevance. The longer the regulation periods and thus the time lags, the higher the incentives for cost reduction and, thus, for adopting cost-saving innovations (cf., for instance, Bailey (1974)). However, Sweeney (1981) show that regulated firms may not exploit the potential of innovations completely or only with a delay, if they expect a regulatory adjustment. This dynamic disincentive of incentive regulation regimes is generally known as ratchet effect: firms may underperform to avoid more ambitious regulatory requirements in the following regulation periods (cf., for example, Freixas et al. (1985)). Armstrong and Sappington (2006) argue that incentive regulation provides substantial incentives for short-term innovation and cost reduction, but the incentives for long-term infrastructure investment are limited.

Bauknecht (2011) and Müller et al. (2011) conclude that most studies on regulation and innovation focus on the telecommunication sector or are not related to any specific sector. One reason why there are rarely studies of the relationship between regulation and innovation in the electricity grid could be the below-average innovative character of the electricity network in the past (see, for example, ETP SG (2010)). Therefore, the problem of regulatory disincentives for investments in electricity grid innovation is a relatively new research area. Obviously, regulation has an important influence on technical change in energy networks via incentives for investment, participation in research and development (R&D) and the implementation of new technologies (cf., among others, Jamasb and Pollitt (2008a)).

In Bauknecht (2011), the disincentive created by regulation on network innovations is discussed. The current (European) regulatory framework is investigated and the point is made that there are significant obstacles to forward investment in smart assets. Meeus and Saguan (2011) found, that even if grid operators innovate, they are confronted with disincentives on the customer side with respect to participation. Müller et al. (2011) argue that incentive regulation encourages innovation in the short-term, since process innovation can lead to a reduction of OPEX. This cost reduction results in higher profits for the grid operator within the regulation period. The long-term effect has not yet been investigated, so that there are no results for the effect of incentive regulation on product innovations (CAPEX) that are associated with investments like smart solutions. Meeus and Saguan (2011) point out that incentives for reducing CAPEX are more difficult to implement than for OPEX. The main reason is that CAPEX are caused by investments with significantly larger payback periods than the duration of the actual regulation period. Studies provide some evidence that incentive regulation has contributed to a decline in R&D and innovation (see Jamasb and Pollitt (2008b)). Summarizing the literature, it is evident that incentive regulation gives positive incentives to invest in innovations which achieve cost-saving effects in the short-term. Yet, the effect on innovations with a long-term time horizon and a crucial impact on CAPEX remains a research objective. Furthermore, studies focusing on the electricity sector are still rare.

This chapter shows the incentives and disincentives of a concrete ‘standard’ incentive regulation system on the implementation of product innovations. In contrast to the existing literature, which is mainly theoretical, we highlight and evaluate the most important influencing factors of a specific electricity regulation system. On this basis, ways to consider innovation in incentive regulation systems for electricity grid operators are discussed. For this, the German revenue cap regulation is taken as an example and further investigated on critical mechanisms with respect to providing incentives in investing in general and investing in innovations in particular.

6.2.3 German revenue cap regulation

Below, it is investigated whether there are incentives or disincentives for investment in innovations under 'standard' incentive regulation, whereby the focus is on the German revenue cap regulation of distribution grids. With the German revenue cap regulation, the profitability of investment is influenced by the following factors:

1) First of all, the **allowed rate of return (r_{all})** is an important value, as it describes the theoretical internal rate of return of dedicated assets. Since the costs are decoupled from revenues, these costs are determined in a given year before the next regulation period. This so-called photoyear is decisive for future revenue caps.

2a) The determination of costs in a photoyear induces costs occurring after the relevant photoyear only being taken into account in the next photoyear. Therefore, these costs cannot be incorporated in the allowed revenue until the start of the next-but-one regulation period, meaning that the **time lag** between cost and revenue increases. This mechanism is shown in Figure 6-1. It has a massive impact on profitability, since costs remain with the company, but do not lead to an increase in the revenue cap.

2b) To moderate the effect mentioned in 2a) for distribution system operators, the **enlargement factor** has been implemented. This factor enables an increase in the allowed revenues as soon as a substantial change in the supply task (e.g. due to a considerable increased supplied area) is given. However, it is only applicable if some parameter change (e.g. supplied area, number of connection points and number of distributed generators) exceeds a predefined value. The revenue cap is then raised to take into account increased costs which are assumed to accompany the requirements which follow, for example, from the extended supply task. Thus, the corresponding costs are considered 'indirectly' in the revenue cap, if the enlargement factor can be used. Thereby the enlargement factor can be applied until the end of June of each year with an increase of the revenue cap in the following year. Consequently, the time lag between incurred costs and consideration in the revenue cap is reduced.

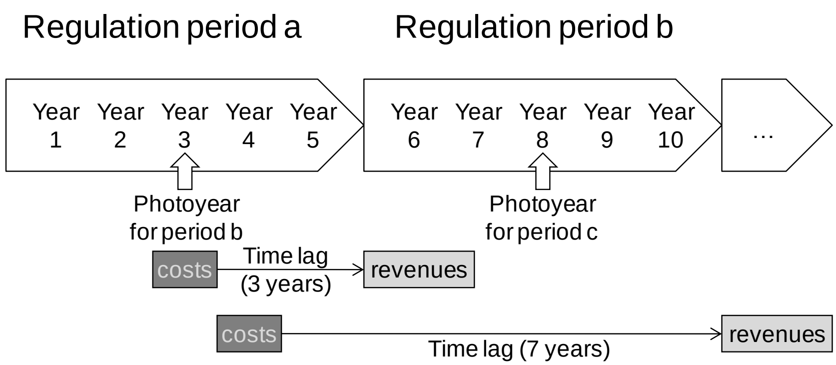


Figure 6-1: Time lag in incentive regulation

3) For investments which fulfill specific requirements and in the case of investments for integrating RES-E, there is an opportunity to request approval of certain **investment budgets**. These budgets are primarily addressed at transmission system operators and approved for distribution system operators only in exceptional cases (see § 23, 6 ARegV). The investments only fulfill the requirements, if they are not included in the enlargement factor and if they increase total expenditure (TOTEX) by at least 0.5% after subtracting permanent non-influenceable costs. If accepted, the investment budgets are declared as permanent non-influenceable costs.
4) The **classification of costs** as either influenceable or non-influenceable has an impact on profitability, since influenceable costs are faced with cost pressure resulting from efficiency objectives (*X*-factors). In contrast, the *X*-factors are not applied on non-influenceable costs, because it is assumed, as the name implies, that these costs are not in the sphere of influence of the grid operator (see the example in Subsection 2.1.3). The classification of costs is performed by the regulation agency in the year after the photoyear.
5a) In incentive regulation systems, two different types of **efficiency objectives** are usually implemented, which are the general and the individual *X*-factor. The **general *X*-factor** applies to all grid operators and thus reduces the revenue cap of them all. Hence, this general *X*-factor forces all grid operators to increase productivity. The underlying assumption is that the complete sector, in this case all DSOs, are inefficient in comparison to other (competitive) sectors. The general *X*-factor is defined as a percentage rate by which the revenue cap declines. In general, the specific percentage rate is determined by law or by the regulatory authority.
5b) The individual efficiency of each grid operator is considered in the **individual *X*-factor**, which is derived from the individual efficiency[33] of one specific network operator, in relation to the others. To determine this additional and individual efficiency objective, a benchmark of all distribution system operators is conducted by the regulatory authority. The efficiency of the DSOs is estimated by using efficiency analysis methods (see below). The resulting estimated individual efficiency value (denoted by θ) is used to calculate the individual efficiency objective (denoted by x_{ind}) as follows:

$$x_{ind} = \frac{100\% - \theta}{a_{per}},$$

where a_{per} denotes the length of the regulation period. The curve of the revenue cap is influenced very substantially by the individual efficiency objective - the lower the efficiency value θ, the higher the efficiency objective x_{ind} and the steeper decreases the revenue cap. Hence, a high individual X-factor x_{ind} places more pressure on lowering costs in order to remain profitable. However, as mentioned previously in the elaborations for the influencing factor 4), the efficiency objectives affect only the influenceable costs.

The estimated efficiency values depend on the selected efficiency analysis method and the used input and output parameters. The two most popular methods for estimating efficiency are Data Envelopment Analysis (DEA) and Stochastic Frontier Analysis (SFA). DEA is a linear programming model originally introduced by Charnes et al. (1978) and extended, among others, by Banker et al. (1984). DEA develops an empirical frontier

[33] According to the elaborations in Subsection 2.1.2 and in Coelli et al (2005) there exist numerous definitions and dimensions for efficiency. In the context of this research, efficiency is defined as a ratio of output to input, whereby a higher ratio indicates an increased efficiency value.

function the shape of which is determined by the most efficient producers in the observed data set. Efficiency is measured as the distance to the frontier. SFA, developed by Aigner et al. (1977) and Meeusen and Van den Broeck (1977), is an econometric approach, which integrates two unobserved error terms representing inefficiency and statistical noise. Assuming a production function and specific distributions for the error terms allows estimation via, for example, the maximum likelihood method. Due to the fact that both DEA and SFA have their specific advantages and disadvantages, neither can be regarded as the superior method. Hence, in regulation practice, it is considered best-practice to apply more than one method and/or further subtypes of these approaches (see Haney and Pollitt (2009)). In the German regulatory system, DEA and SFA are applied.

In addition to the selection of the estimation method, the choice of expedient input and output parameters for the grid operators is a challenge, because it is not easy to define what exactly constitutes the input and output of a grid operator (see, for example, Jamasb and Pollitt (2000)). In general, the input and output parameters for the benchmark are chosen by the regulation agency, but some of them are defined by law. The parameters used in the first German regulation period of electricity grid operators are described in Sumicsid (2008). The costs are defined as input and the output is given by a number of parameters including the length of cables, number of connection points and area provided.

The efficiency analysis is the core element of incentive regulations. Hence, the influence of different investment alternatives on the efficiency analysis is considered in Subsection 6.4.1. To be able to integrate this impact in the profitability calculations of grid operators, first the mathematical formula is derived for these economic calculations in the next section.

6.3 Approach – Economic calculation

In the following analysis, an approach for calculating the internal rate of return (IRR) of investments is developed, considering the specifics of incentive regulation systems. This approach enables us to compare the profitability of several investment alternatives under incentive regulation. The investment alternatives differ mainly in their impact on efficiency objectives and the potential to consider costs in the revenue cap.

In incentive regulations, the investment costs are classified as CAPEX. This is implemented by annual depreciation (over the lifetime of the asset) and the (allowed) rate of return as interests on the tied up capital. However, an investor (the grid operator) only invests, if his expected ‘real’ rate of return is adequate in comparison to other investment options. The intended (allowed) rate of return may differ from the ‘real’ one. Accordingly, the determined efficiency objective, the time lag between the occurrence of costs and their consideration in the revenue cap and the classification of costs are important parameters. Below, the specific influences of various parameters on the ‘real’ internal rate of return are shown. In order to obtain meaningful results, it is abstracted from further factors like OPEX and the general X-factor.

Below, the general formula for the IRR is described first and then the equations for annual earnings and payments are derived. This is necessary to integrate the annual contributions into the payment series, so as to calculate the IRR. The new investment is performed in t_0. Furthermore, it is necessary to distinguish between three time intervals, in order to consider appropriately the influence of the existing asset base, the new investment and the specifics within the regulation system.

- Interval 1: new investments (e.g. for conventional reinforcement or storage capacities) are not considered in the revenue cap from t_1 until t=$t_{1\text{per}}$. Accordingly, t_1 represents the starting point of the calculation of annual earnings and payments, whereby $t_{1\text{per}}$ is the starting point of the next regulation period. In this Interval 1, the interest payments are only given for the existing asset base and new investments only cause costs, but are not considered in the revenue cap.
- Interval 2: new investments are considered in the revenue cap from the starting of the next regulation period onwards. The period Interval 2 lasts as long as the regulation period (this duration is denoted as a_{per}). Hence, the end of Interval 2 (denoted as $t_{2\text{per}}$) is characterized as t_{1per}+a_{per}. Within Interval 2 the influenceable costs resulting from the efficiency value θ decline to zero (more on this later).
- Interval 3: this interval is relevant beyond the next regulation period until the (calculated) lifetime T_L of the investment. The influenceable costs are no longer relevant in this interval, since a reduction to zero is required in Interval 2.

This distinction enables us to calculate the profitability of investments over their full lifetime. Figure 6-2 provides an overview of the time intervals and the corresponding notations. The specified characteristics of the different time intervals are explained in more detail in due course.

Before deriving the characteristics of the three time intervals, a few basics of the approach are described. In this economic calculation, the general formula of the internal rate of return method described in Promislow and Spring (1996) is used. The internal rate of return (IRR) is defined as the rate that makes the present value of future earnings equal to the cost of the investment (see Dean (1951)). In other words, it is the rate which is necessary for discounting the future payment surpluses to achieve a net present value of zero. The IRR is a suitable measure for interest rates of tied up capital and therefore, it seems an appropriate method for the analysis. The equation is:

$$0 = -I_0 + \sum_{t=1}^{T_L} (E_t\text{-}P_t) \cdot \frac{1}{(1+r)^t} + \frac{L_n}{(1+r)^n} \qquad (6\text{-}1)$$

with
I_0 = payment (investment) in t=0
E_t = earnings in period t
P_t = payment in period t

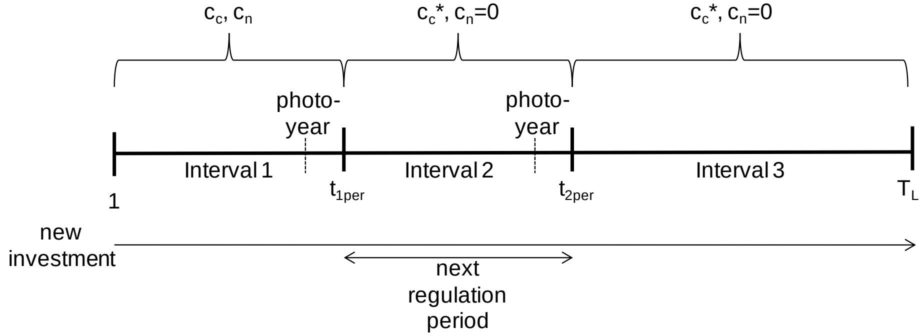


Figure 6-2: Overview of intervals in the economic calculation

L_n = earnings for liquidation in period n
r = 'real' internal rate of return (unknown)
T_L = (calculatory) lifetime
(see appendix A.6.I for an overview of all notations).

This formula can be simplified by assuming L_n=0 and calculating the internal rate of an investment within its (calculatory) lifetime T_L. This is a permissible assumption, due to the fact that the liquidation of installed grid assets is almost impossible, since it is a very specific investment, i.e. an alternative use at other geological sites or for other purposes is too cost-intensive. Hence, the investment is characterized as sunk costs (see Brunekreeft (2003)). The equation (6-1) is changed to:

$$0 = -I_0 + \sum_{t=1}^{T_L}(E_t\text{-}P_t) \cdot \frac{1}{(1+r)^t} \qquad (6\text{-}2)$$

Equation (6-2) is the basic formula in the derived approach. If, for each year of the calculated lifetime T_L of investment I_0, the earnings E_t and payments P_t are given, the 'real' internal rate of return r can be calculated with a standard tool. Hence, the objective of the derivation is to calculate r using the payment series with its annual contributions (E_t and P_t). To attribute the annual contributions to the payment series, a detailed view of E_t and P_t is required.

In the following analysis, the formulas for E_t and P_t are derived to be applied to the first time interval. First the focus is on the effect of time lags, which is especially relevant in the first time interval. It has to be distinguished between two different effects, with regard to the 'revenue cap relevance' of costs:

- On the one hand, costs can be considered as relevant to the revenue cap. With regard to CAPEX, depreciation and interest are cost types and therefore included in the calculation of the revenue cap [see, for example, Section 6 of German incentive regulation (ARegV)]. The costs which are included in the revenue cap are notated as considered costs c_c. This applies to the costs of the existing asset base, because these are considered in the revenue cap.
- On the other hand, costs may not be relevant for calculating the revenue cap. This is particularly the case with costs occurring after the photoyear and which are thus affected by the time lags described in Subsection 6.2.3 and depicted in Figure 6-1. In this case, the costs (depreciation and interest) are not part of the revenue cap, since they have not yet been taken into account. To be more precise, the grid operator faces the additional costs, but an unchanged revenue cap. This cap does not change until the next regulation period. The costs not considered in the revenue cap are notated as c_n.
- The sum of both forms of cost constitutes the total CAPEX cost of the grid operator: $c=c_c+c_n$.

In the derived approach, we assume that the costs of the existing asset base are not confronted with efficiency pressure and earn an internal rate of r_{all}. Thus, r_{all} is defined as the allowed rate of return, which is set by the regulation agency. Hence, the 'real' IRR and the allowed IRR are the same for the existing asset base. The number of years for which costs are considered in the revenue cap is denoted by t_c. This time period is relevant for calculating the compound interest, which is part of annual earnings and contributes to E_t. As an element of the described approach, the number of years for costs for not being included in the revenue cap also has to be considered. This parameter is denoted with t_n. This approach is based on the relevance of opportunity costs, since the company may have invested in other opportunities with a comparable interest rate (see, for example, Becker et al. (1974) and Heymann and Bloom (1990)). Thus, it can be assumed that the next best investment option has the same interest rate r_{all}. Therefore, these annual amounts should be regarded as costs and contribute to P_t. For the annual payments, we obtain P_t (opportunity costs) and earnings E_t in Interval 1:

$$E_t = \frac{c_c}{t_L} \cdot \left(1 + r_{all}\right)^{t_c} \qquad \text{for } 1 \leq t \leq t_{1\text{per}} \qquad (6\text{-}3)$$

$$P_t = \frac{c_n}{t_L} \cdot \left(1 + r_{all}\right)^{t_n} \qquad \text{for } 1 \leq t \leq t_{1\text{per}} \qquad (6\text{-}4)$$

Equations (6-3) and (6-4) describe the annual (re-) payment resulting from depreciation and interest. The longer the time period to the next regulation period, the greater the value of t_n and the larger the opportunity costs assigned in the payment series. The described (re-) payment calculation is valid until the next regulation period begins.

For Interval 2 in the approach, a few more influences have to be considered. Firstly, the three cost classifications have to be integrated. Besides assorting costs in terms of 'revenue relevance', the German incentive regulation distinguishes between **the levels of influenceability of costs**. Total costs are the sum of permanent non-influenceable costs c_{pni}, temporarily non-influenceable costs c_{tni} and influenceable cost c_i, so that we obtain: $c=c_{pni}+c_{tni}+c_i$. Accordingly, this yields the relative shares of these three cost components: $s_{pni}=c_{pni}/c$, $s_{tni}=c_{tni}/c$, $s_i=c_i/c$ and $1=s_{pni}+s_{tni}+s_i$. This classification is important, since permanent non-influenceable costs are not subjected to efficiency objectives. In contrast, influenceable costs c_i, which are declared as inefficiencies, should be reduced to zero until the end of the regulation period (see also Subsection 2.1.3 and the example in Figure 2-1).

Furthermore, the starting time of the next revenue cap is relevant (denoted in the approach as t_{1per} and which constitutes the starting point of Interval 2). In the photoyear after the investment was performed, both cost-forms (the 'existing' cost base c_c and the new investment costs c_n) are considered as the costs c_c* in the revenue cap determination. Thus, no opportunity costs occur and all costs are considered in the revenue cap. The cost base c_c* is the sum of c_c and c_n, but from this point onwards including the efficiency objective. This adjustment of equation (6-3) is necessary, due to the fact that influenceable costs c_i have to be reduced within the regulation period. Consequently, the earnings E_t for Interval 2 are calculated by replacing c_c by c_c* in (6-3), obtaining for the annual earnings:

$$E_t = \frac{c_c^*}{t_L} \cdot \left(1 + r_{all}\right)^{t_c} \qquad \text{for } t_{1\text{per}} \leq t \leq t_{2\text{per}} \qquad (6\text{-}5)$$

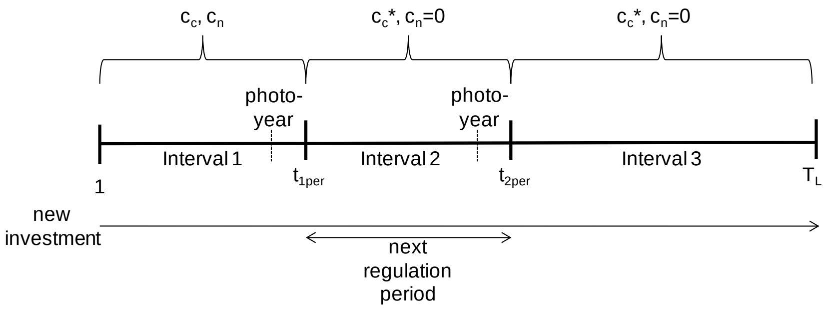
Equation (6-5) is the basic formula for the following derivations in Interval 2. There are no more opportunity costs and therefore no payments P_t. Equation (6-5) is the only amount contributing to the annual payment flows from this point in time onwards. In order to implement the decrease in the revenue cap in the annual repayments, due to the reduction in influenceable costs, equation (6-6) is derived:

$$c_c* = (c - \frac{c_i}{a_{per}} \cdot n_{per}) \tag{6-6}$$

The considered costs $c*$ are thus calculated by subtracting the influenceable costs c_i from the total cost base c. The length of the regulation period a_{per} is fixed (e.g. 5 years). The particular year within the regulation period is relevant for the payment flows, since it describes how many of the influenceable costs have to be reduced up to that year and how much the revenue cap has been lowered. The year is denoted by n_{per} and can assume values from the set $\{1,\ldots,a_{per}\}$. At the end of the regulation period, all influenceable costs must be eliminated.

For Interval 3, the influenceable costs resulting from the new investment are no longer relevant, since this amount must already be reduced to zero. With consideration of the compound interest, from this point on it is calculated with a perpetual annuity until the end of the (calculated) lifetime of the assets. This seems reasonable, since the regulation regime and the input and output parameters are not known for this time interval. In a next step, the derivation of the annual earnings with respect to the influence of the efficiency objective, which is relevant for both Intervals 2 and 3, is finalized. Prior to this and for the sake of clarity, the previously determined influences for calculating the different time intervals are illustrated by being integrated in Figure 6-3.

In order to finalize the derivations for the annual earnings E_t for Interval 2 and 3, the individual efficiency value θ of each grid operator is considered in the calculation. This step is necessary, since θ determines the level of influenceable costs which have to be reduced to zero within the regulation period. As described in Subsection 6.2.3, θ is determined as an individual value for each grid operator by a benchmark. In order to implement the efficiency value directly into the calculation, the relationships $c=c_{pni}+c_{tni}+c_i$ and $s_{pni}=c_{pni}/c$ are considered, which are described above. Furthermore, the temporarily non-influenceable costs c_{tni} are calculated by multiplying the efficiency value by the difference of total costs c and permanent non-influenceable costs c_{pni}.



Opportunity costs for new investment	yes	no	no
Pressure to reduce influenceable costs	no	yes	no, but consideration of reduced revenue cap for period 2
Efficiency value takes effect	no	yes	no

Figure 6-3: Overview of the intervals in the economic calculation (detailed)

$$c_{tni} = \theta \cdot \ (c\text{-}c_{pni}) \tag{6-7}$$

Now the equations (6-6) and (6-7) are combined considering the described relationships in equation (6-5) to reveal the influence of the efficiency value and the share of permanent non-influenceable costs (the complete derivation is shown in Appendix A.6.II):

$$E_t = \frac{c(1-\frac{(1-s_{pni})\cdot(1-\theta)}{a_{per}}\cdot n_{per})}{t_L}\cdot\left(1+r_{all}\right)^{t_c} \qquad \text{for } t_{1per} \leq t \leq t_{2per} \tag{6-8}$$

This equation enables the calculation of annual repayments of CAPEX within the incentive regulation. In a final step, the influence of the compound interest is readjusted. Because the investment alternatives differ with respect to their consideration as costs in the revenue cap, the interest also differs. While the counting of years starts immediately for the existing asset base (already implemented in the revenue cap), the time lag for the costs of new investments being considered in the revenue cap leads to a delay of interests for the tied up capital. Therefore, the repayment formula has to be extended. It has to be distinguished in (different) numbers of years for the costs considered in the revenue cap. For the two different durations of the existing cost base c_c and the new investment c_n, we use t_c and $t_{c,n}$, respectively. Thus, the costs c in equation (6-8) have to be split up into c_c and c_n to implement t_c and $t_{c,n}$. For the sake of transparency, this step is performed in formula (6-9) after deriving the formula for the impact of efficiency value θ and the share of permanent-non-influenceable cost s_{pni} (equation (6-8)). For the readjusted earnings, we obtain:

$$E_t = \frac{c_c(1-\frac{(1-s_{pni})\cdot(1-\theta)}{a_{per}}\cdot t_{per})}{t_L}\cdot\left(1+r_{all}\right)^{t_c} + \frac{c_n(1-\frac{(1-s_{pni})\cdot(1-\theta)}{a_{per}}\cdot t_{per})}{t_L}\cdot\left(1+r_{all}\right)^{t_{c,n}} \qquad \text{for } t_{1per} \leq t \leq t_{2per} \tag{6-9}$$

Equation (6-9) is valid, given all costs are considered in the revenue cap and the efficiency value takes effect. In addition to equations (6-3) and (6-4) for the prior years (Interval 1), the annual earnings and payments are derived that can be integrated into equation (6-4) for Interval 2. Furthermore, the perpetual annuity for Interval 3 can be integrated as described previously. For this purpose, equation (6-9) is also integrated into equation (6-2), since, for Interval 3, all influenceable costs caused by the new investment have been reduced to zero in the preceding Interval 2. However, in Interval 3, no further decline of the revenue cap is intended, so that the annual earnings differ only as a result of the effect of compound interest.

Using the presented approach, the internal rate of return IRR corresponding to the ‘real’ rate of return r can be calculated. This enables the calculation of different investment scenarios. The impact of different investments on the efficiency values (θ) and the corresponding individual efficiency objectives x_{ind} can now be evaluated. Furthermore, the influence of the share of permanent-non-influenceable costs s_{pni} and the time lags for costs, as being integrated into the revenue cap on the real IRR, can be demonstrated. The specific impacts by means of a case study are shown in Section 6.4.

6.4 Case study

In this section, the profitability of different investment strategies is determined. In order to do so, the IRR for the complete asset base and the isolated investment is investigated. Both perspectives are necessary, because the latter depicts the attractiveness of new investments in incentive regulations, while the former shows the impact of the new investment on the overall profitability. In particular, overall profitability is influenced by the changing individual efficiency objective x_{ind}, which is influenced by the investment strategy for the new investments. In other words, the IRR is not a weighted average of the IRR of existing assets and new investment. Instead, the new investment exerts an impact on overall profitability due to the influenced efficiency objective, which is also valid for the complete asset base. Furthermore, the time lag for the costs of the new investment as considered in the revenue cap exerts an impact on the IRR of the complete asset base. Five cases are investigated, focusing on the perspective of a single grid operator:

- In the basic scenario (Scenario I), all grid operators invest in conventional reinforcements of the grid. In Scenario (Ia) the costs of the additional assets for the considered grid operator are not classified as permanent non-influenceable costs and are therefore faced with efficiency pressure, while in Scenario (Ib), they are classified as permanent non-influenceable costs.
- In Scenario II, the grid operator refuses grid access to the new RES-E plants, because it claims that the costs of connection and transport of this renewable energy generation plant are not ‘economically reasonable’.[34]
- In Scenario III, the grid operator invests in smart solutions like local storage capacities or voltage regulation appliances (see Subsection 6.2.1). This scenario differs from Scenario I in terms of the different individual efficiency objectives x_{ind} and the investment level, since investment in smart solutions can be more expensive than conventional reinforcement (see Subsection 6.4.1). Note that as described above, these innovations may positively influence efficiency in the long run. However, this dynamic efficiency has not yet been considered and encouraged by current regulation regimes (cf. Müller et al. (2011)). In Scenario (IIIa), the costs are not classified as permanent non-influenceable costs, while in Scenario (IIIb) they are classified as such.[35]

Firstly, some basic conditions for the different scenarios are given. The investment decision is taken in year t_0. This is the year for cost determination and efficiency estimation (photoyear). The investment decision changes the input and output parameters, since it increases the costs and can have an impact on structural data (e.g. length of cables). This can influence the efficiency objective and a new efficiency objective affects the curve of

[34] In several feed-in laws (this also applies to the German EEG), grid operators can decline a connection of RES-E if costs are not ‘reasonably economical’. This legal term is anchored in the laws, in order to avoid economically pointless investments on grid side, often without further specifications (see later in the discussion in Section 6.5).

[35] Note that Scenarios Ia and IIIb, with a classification of the costs as permanent non-influenceable, are enabled in current German incentive regulation only by approval of investment budgets (see Subsection 6.2.3). Nevertheless, the impact of the classification of costs can be shown considering these scenarios.

the revenue cap in the next regulation period. The next regulation period starts in t_3 and lasts five years, so that the determined inefficiencies must be eliminated from period t_3 to t_8. Beyond t_8, the annual contributions are calculated with a perpetual annuity as described in Section 6.3.

This scenario can be changed to show the influence of a longer time lag. If investment is made in t_0, but the photoyear is at t_1, the costs will be effective for the revenue cap in t_4 and the (potentially) new efficiency objective affects the revenue cap between t_4 to t_9. The only way to achieve an earlier consideration of costs as revenues is by using the enlargement factor (as described in Subsection 6.2.3). The time lag between costs and their consideration in the revenue cap can also be extended to seven years, as shown in Figure 6-1 and described in Subsection 6.2.3.

The scenarios I/III a and I/III b differ with regard to the classification of costs of the new investment - considered as permanent non-influenceable costs or influenceable costs, which are faced with efficiency pressure. For the existing asset base, it is important to consider the share of permanent non-influenceable costs as well. This share for the existing asset base is calculated with s_{pni}=50 %. Furthermore, for the regulation period a_{per} a duration of 5 years is chosen. The allowed rate of return r_{all} is set with 6.3 %.

As mentioned in Section 6.3, the efficiency objective is an important parameter in incentive regulations. The calculation of profitability is only possible if an efficiency value θ is given. Thus, in the next section, it is described how the efficiency for the various scenarios is calculated.

6.4.1 Assessment of efficiency

Below, the influence of investment alternatives on the efficiency values is analyzed. For this purpose, the database from Andor (2009) is used. The data set contains the data for 50 German distribution system operators from 2007, namely the highest annually peak load in MW, the grid length in kms, the number of extraction points, the supplied area in kms and the estimated total costs in Euros. Except for the estimated total costs, all information were published by the distribution system operators, because they are obliged to do so by German law (§ 27 StromNEV and § 17 StromNZV). Because total costs are confidential, they had to be estimated. The basic assumption for this estimation is that revenue equals cost. This assumption is indeed valid, since German DSOs were regulated by cost-based regulation in 2007. Although this estimate may be rather rough, it is sufficient for our purposes. The following analysis does not aim at estimating the correct individual efficiency values, but to evaluate the influence of new investments on an existing DSO and its efficiency values, i.e. the variation of efficiency values due to the new investment. Hence, the input variable is the estimated total cost in Euros and as output variables, the highest annual peak load in MWs, the grid length in kms and the number of extraction points per km of supplied area.

For the investment alternatives, it is assumed in this use case that there is a need to enlarge the current grid length by 10 percent in one regulation period, in order to integrate the growing decentralized RES-E generation. This must be regarded as a conservative estimate of projected values for German grid operators (see Section 1.2). Furthermore, it is assumed that one km of grid length costs 100.000 Euros. For the investment in smart solutions, two different assumptions are made. Firstly, in Scenario (III*), it is assumed that an investment in smart solutions, needed to achieve the same effect for the integration of RES-E, is as expensive as the grid extension. Secondly, in Scenario (III**), its cost is twice as high. These assumptions probably underestimate the cost advantages of conventional investments with respect to current smart solutions, for instance, in regard to storage capacities. VDE (2008), for example, estimates that the costs of local storage capacity are at least five times higher than those of conventional investments. However, as shown in this thesis in Section 4.5, this value may also be significantly lower depending on the prevailing grid situation.

Of course, an investment in storage capacity is only viable, if the advantages (see Section 2.2) outweigh the possible investment cost disadvantages, at least in the long run. We assume that without regulation, the grid operator would be indifferent between the two investment options, i.e. the advantages of smart solutions compensate exactly for the cost disadvantages. Thus, in this approach without incentive regulation, the grid operator would expect the same IRR for the alternatives.

The following results are the elementary efficiency estimates of SFA and DEA. Thus, it is abstracted from other specific German rules to determine the efficiency value, because these rules veil the general effects.[36] The reference scenario is that all distribution system operators (DSOs) invest in the conventional grid extension (scenario I). Table 6-1 shows the results for DEA and SFA, in the case that each DSO undertakes this type of investment. It is obvious and in the literature well-known, that the efficiency estimates of SFA and DEA differ to some degree for most of the DSOs and can differ substantially (for some). This effect is visible in Figure 6-4, which provides the efficiency values for the DSO, whereby each number corresponds to a certain DSO. An example of these large differences

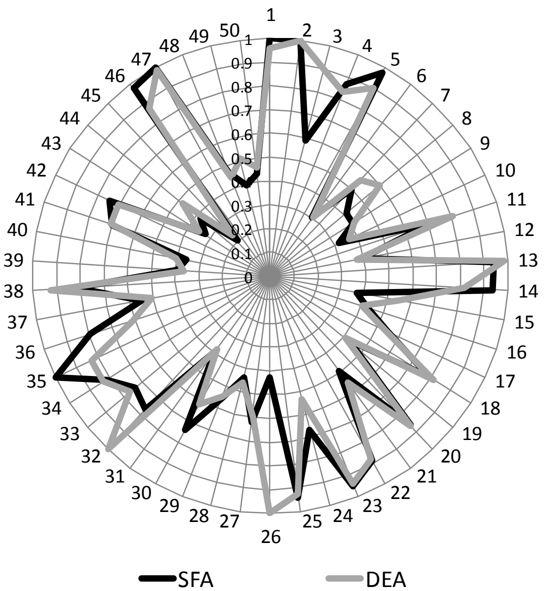


Figure 6-4: Results of DEA/SFA - all DSOs invest in conventional reinforcement (scenario I)

[36] These rules are the Best-of-Four-Approach and an efficiency minimum level of 60%. In the German incentive regulation, the efficiency of a single grid operator is determined by the so-called Best-of-Four-Method. Within this approach, DEA and SFA are each executed twice with two different input parameters (costs and standardized costs). The individual efficiency is then the highest of the four resulting efficiency estimates. Furthermore, there is an efficiency minimum level of 60%, i.e. independent of the estimates, the efficiency value of a DSO can never be lower than 60%.

is the result for DSO 3, with deviations between SFA and DEA for Scenario I of over 30%. However, for the purpose of our research, these differences are not relevant. It is more important to compare the results of the different scenarios for the investment strategies.

Now it is analyzed how an individual DSO influences its efficiency value, by choosing a different investment option to the other DSOs. Each DSO can choose between the options of investing in grid enlargement (Scenario I), in smart solutions (Scenario III) or not investing at all (Scenario II). The presented data in Appendix A.6.III show for all DSOs, how the individual efficiency value is influenced by the investment decision. Accordingly, the efficiency is estimated for one specific DSO changing its strategy, while the other DSOs' decisions are fixed for the basic reinforcement strategy of conventional investment. Below, the results are discussed based on Table 6-1, which highlights the results for two elected DSOs.

- For some DSOs, the investment decision exerts only a minor influence on the efficiency value. Thus, for example for DSO 50, the efficiency value differs at most by 2.29 percentage points for a given method (SFA and DEA).
- In contrast, for some other DSOs, the investment decision can have a crucial impact on the efficiency value. The efficiency value of DSO 3 varies from 51.83% (SFA) or 72.88% (DEA), if it invests in smart solutions, to 66.77% (SFA) or 93.89% (DEA) if it refuses the investment.

The last row in Table 6-1 gives the average results of the four scenarios for all 50 DSOs. On average, the best investment decision regarding the efficiency value, is to refuse the investment altogether. In comparison to the conventional investment, the DSO can improve its efficiency value by about 2.90 (SFA) or 2.4 (DEA) percentage points, respectively. If the DSO is forced to invest, the conventional reinforcement investment is preferable. Even if the investment in smart solutions costs the same as the conventional one, the mean efficiency value is lower. The efficiency value declines by 0.54 (SFA) and 0.98 (DEA) percentage points, if the DSO invests in smart solutions, instead of conventional grid extension. In the case that the smart solution is more expensive, which is much more realistic, this effect intensifies.

Figure 6-5 shows the average results calculated by SFA and DEA, respectively. It is clear that the numeric results are only valid under the specified assumptions and the specific data used. However, the results obviously indicate that the investment decision has

Table 6-1: Influence of investment alternatives on efficiency values for elected DSOs.

Scenario / DSO	SFA				DEA			
	I Conventional	**II Refused**	**III* Smart***	**III** Smart****	**I Conventional**	**II Refused**	**III* Smart***	**III** Smart****
3	58.93%	66.77%	58.36%	51.83%	90.26%	93.89%	82.06%	72.88%
50	43.61%	44.29%	43.19%	42.15%	46.18%	47.36%	46.18%	45.07%
Average (all)	63.59%	66.49%	63.05%	59.46%	65.63%	68.04%	64.65%	61.27%

*Smart solution has the same costs as the conventional investment;
**Smart solution has twice the costs as the conventional investment.

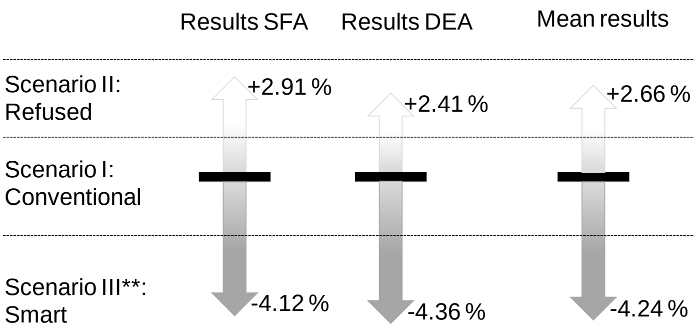


Figure 6-5: Average influence of investment alternatives on efficiency values

crucial impact on the efficiency values. Furthermore, it demonstrates the general tendency that DSOs have incentives to avoid investment and disincentives to innovate.

According to Figure 6-5, the average efficiency value of a conventional investment and a smart solution are around 2.7 and 6.9 percentage points lower, respectively, than in the case of refusing the investment. Given these results, the following case study considers an efficiency value

- for Scenario I (‘conventional reinforcement’) of 97.3 %,
- for Scenario II (‘investment refused’) of 100% and
- for Scenario III (‘smart solution’) of 93.1%.

6.4.2 Calculation of profitability

In this section, the results for the profitability of investments are presented, calculated using the approach derived in Section 6.3. For analyzing the different scenarios, first the focus is on the profitability of the new investment. The new investment leads to different levels of investments and – even more important – different efficiency objectives. These effects have to be considered in the calculation.

For the isolated view of the new investment, the IRR is shown in Figure 6-6. The possible scenarios are conventional reinforcement (Scenario Ia) and the smart solution (Scenario IIIa). For these two cases, the investment costs are declared as influenceable. Scenarios (Ib) and (IIIb) can be regarded as one case, since the costs for both investment strategies are classified as permanent non-influenceable. Thus, no efficiency objective leads to pressure to reduce costs, regarding this investment, and no difference regarding the strategy (conventional or smart solution) has to be considered. Hence, the Scenarios Ib and IIIb are aggregated in the third relevant scenario. The existing asset base is excluded, so that Scenario II is not relevant, since no investment is undertaken and no profitability can be calculated. The IRR of the different scenarios is depicted in Figure 6-6, depending on the corresponding time lag between costs and their inclusion in the revenue cap.

The results show that the changed efficiency values estimated in the benchmark are a major influence factor on the IRR. As the smart solution scenario is the one with the lowest efficiency value, it clearly lowers the profitability of the new investment. The difference in the classification of influenceable (a) and permanent non-influenceable (b) costs has a minor impact. Furthermore, the time lag is a very important factor. If the new investment is considered in the revenue cap with a delay, the IRR is affected considerably. For example,

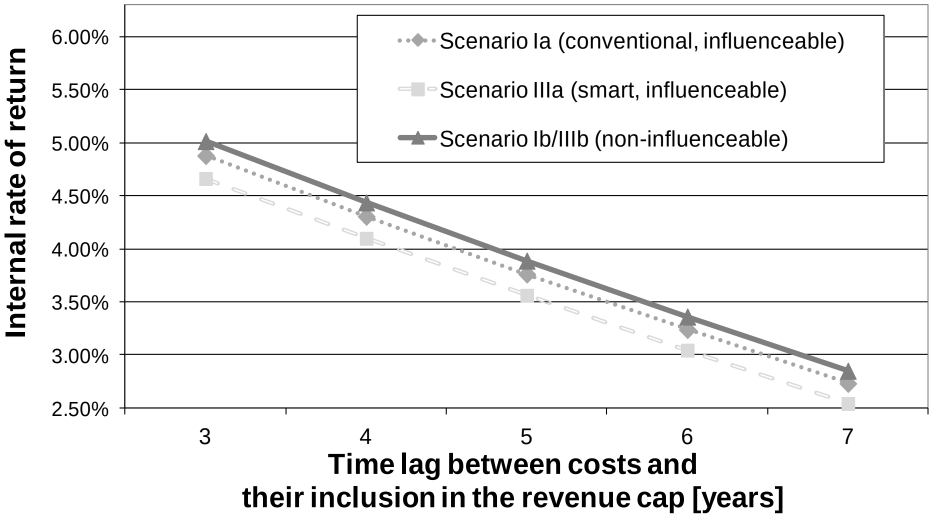


Figure 6-6: IRR of new investment

if in Scenario (Ia) the time lag for the new investment rises from 3 to 7 years, the IRR for the investment decreases from 4.9% to 2.7%.

In the remainder of the analysis, the IRR of the complete asset base is calculated. When considering this base, the efficiency objective remains essential. The change in the efficiency objective is caused by the new investment, but, nevertheless, the new efficiency objective is relevant also for the complete asset base. Five scenarios are relevant for calculating the complete asset base IRR.

- Scenario I: the new investment in conventional assets is declared as influenceable costs (Ia) or permanent non-influenceable costs (Ib).
- Scenario II: the reinforcement is refused, so that only the IRR of the existing asset base is relevant.
- Scenario III: the new investment in smart assets is declared as influenceable costs (IIIa) or permanent non-influenceable costs (IIIb).

Figure 6-7 shows the IRR for the complete asset base for the different scenarios. The results confirm the statements with respect to the analysis of the isolated view of the new investment. The changed efficiency value clearly reveals the changed profitabilities of the different strategies; the smart solution – the scenario with the lowest efficiency yields the lowest profitability. The deterioration with respect to the other strategies (conventional reinforcement or refusal of investment) is quite pronounced. The difference in the classification of influenceable (a) and permanent non-influenceable (b) costs is almost negligible in Figure 6-7, since it describes only whether or not efficiency pressure affects the additional investment. This effect is cushioned by the existing asset base, since the CAPEX of the new investment is considerably smaller than that of the existing asset base. Note that only the impact of the classification of costs is considered by the differentiation of (a) and (b), and not the impact of the efficiency values. Furthermore, in Figure 6-7 the significance of the time lag is again evident. Hereby, a rise of the time lag from 3 to 7 years is again only relevant for the new investment for being considered in the revenue cap. However, the IRR of the complete asset base is affected. Considering again Scenario Ia, the

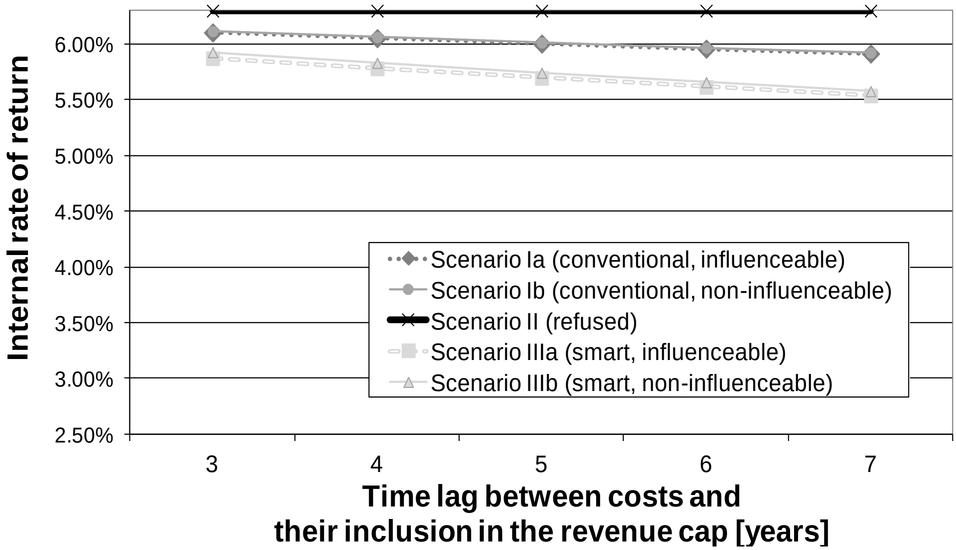


Figure 6-7: IRR of complete asset base

IRR is reduced from 6.1 to 5.9%. This decrease is relevant for the complete asset base and, thus, also for the preceded investments.

The strategy of refusing investment (Scenario II) is clearly rational, since this scenario does not lower the efficiency value and therefore future revenues. It cannot be a policy and overall economic objective to support this strategy, as the further integration of renewable energy is hampered. As mentioned before, refusal is only possible with the argument of a ‘reasonable economic’ decision.[37] Only if the resulting IRR in the scenarios of conventional reinforcement (I) and smart solutions (III) is higher than comparable alternative interest rates under consideration of risk surcharge, the grid operator is willing to invest. Nevertheless, based on economic considerations, the decision is never made in favor of smart solutions.

Summarizing, the strategy of avoiding reinforcement at all is clearly preferable because the highest profitability values can be achieved. If forced to integrate decentralized RES-E, the strategy of conventional reinforcement is preferable.

6.5 Political implications

The results presented in this section show that ‘standard’ incentive regulation hampers the implementation of innovative smart solutions. Hence, in addition to the funding and further support of research and development of innovative smart solutions, innovation should be also considered within the context of regulation of grids. In this context, a minimum requirement should be that regulation at least does not discourage innovation. Below, we

[37] Note that the definition of ‘reasonably economical’ investment is not at all clear. Hence, legal proceedings may have to judge isolated cases, leading to less investment security of RES-E and an increase in legal cost and complexity.

briefly discuss some ways to establish a level playing field for smart solutions in the regulation system.

- Innovations could be integrated in the efficiency estimation. However, based on the characteristics of the estimation methods, it is not straightforward how this can be realized. One problem is, that an output which is used only by a small subsample, can distort the efficiency estimates of all DSOs. Since it can be assumed that only a small subsample will have smart solutions in the near future, this issue has to be taken into account when incorporating innovation in the efficiency estimation. Furthermore, the determination of an output parameter describing appropriately 'smart solutions' is not only very difficult, it may even hamper an open technological search for suitable solutions to integrate RES-E.
- Our results show that the classification of investments costs as non-influenceable has only a minor impact. Hence, the classification of new smart solution investments (e.g. storage assets, voltage regulation appliances) as non-influenceable costs will probably be insufficient to compensate for the regulatory disincentives.
- The time lag between the appearance of investment costs and considering these costs in the revenue cap, should be as short as possible. A simple shortening of the regulation period is not very conducive, because, in this case, the incentive regulation loses more and more its incentives. The application of an enlargement factor seems an appropriate instrument for shortening the time lag, without losing the cost reduction incentives. An instrument which avoids the time lag at all and compensates the DSO for the reduced IRR, would improve profitability even more. Since this is the case with the investment budgets for TSOs, investment budgets for innovative DSO projects could be an appropriate way of incentivizing innovations. However, this instrument can imply high administrative burden and regulatory involvement, especially with a large number of different DSOs (as it is the case, for example, in Germany).
- Another way to consider innovation is to adjust the allowed rate of return for innovative investments. Because innovations are riskier than conventional investments and, as the results show, are even disadvantaged in the regulation design, the expected rate of return is lower than for conventional investments. Hence, a rational investor only invests in innovations, if he can benefit from the potentially higher returns. Thus, a higher allowed rate of return provides incentives to innovate. However, the determination of the magnitude of the allowed higher rate of return is not simple. The questions 'what is a fair rate of return for risky innovations' or 'what are comparable innovations' are difficult to answer.
- As described above, the funding and further support of research is also a key element. The R&D costs, such as for human resources, are classified as OPEX. Thus, the regulation regime should enable the 'allowance' of these costs as non-influenceable costs for a specific time period. However, external learning effects (so-called spillover effects) can be achieved not only through R&D, but also through learning-by-doing. The implementation of smart solutions yields substantial insight into how potential innovations operate in the real world. The CAPEX for the installation and testing of new assets in demonstration projects enable further market penetration through economies of scale and learning effects. The knowledge and experience gained by these projects could be used for adapting regulation methods to future developments. For instance, determining an

appropriate output parameter for the benchmark, as described at the beginning of this section, could be less complicated as soon as a breakthrough of certain smart assets is evident.

In general, likewise quality regulation, an additional ‘innovation regulation’ may lead in the short run to incentives which are contrary to the aim of the incentive regulation; ‘innovation regulation’ may create incentives to increase costs. However, incentive regulation should not aim only to decrease costs, but to increase efficiency and productivity. If the investment in innovative smart solutions is efficient from an economic point of view, despite the fact that the costs are higher in the short run, it should not be hindered by the regulation design.

Nevertheless, as mentioned previously, we see a need for further, more detailed research of instruments to incorporate innovation into the regulation design. Furthermore, it is necessary to investigate how high the level of additional incentives for innovation should be to establish a level playing field. The consideration of innovation should not lead to an overinvestment in inefficient, expensive potential innovations, but should compensate for the disincentives of the regulation design and leave investors with the decision to invest or not invest in innovations. In fact, this will constitute a major challenge for the regulatory authorities.

In general, we postulate that regulation should not hinder any promising development and thus should be adjusted to new advancements. As an example, Jamasb and Pollitt (2008a) point out that regulation should not exclude a development from a centralized to a highly decentralized electricity system, as described by Patterson (2007).

6.6 Conclusion

The growing, decentralized RES-E generation necessitates investments in the distribution grids. Besides the conventional reinforcement investments like additional cables and transformers, the grid operator may also invest in innovative smart solutions. The purpose of this chapter is to analyze the effects of incentive regulation on the decision of distribution system operators to integrate RES-E. Hence, this work constitutes a contribution to adapting the regulation systems to both current and future requirements.

First of all, the presented results show that the regulation regime incentivizes grid operators to avoid investing at all. In general, German grid operators are obliged to integrate RES-E, but there is the exception that they can refuse connection of distributed RES-E generation, if costs are not ‘reasonably economical’. Such refusal should not be a preferred solution or a policy or overall economic objective, as by this, the further integration of renewable energy is hampered. Therefore, it should be ensured that there are no disincentives for investments in the regulation design.

Secondly, the analysis illustrates that ‘standard’ incentive regulation creates disincentives to invest in smart solutions (e.g. local storage capacities or local voltage regulation appliances). If a grid operator is forced to invest, it is economically better to invest in conventional reinforcement, even when the grid operator is indifferent between the investments, because the regulation design fosters conventional investments. The most important influences in this context are the effects on the efficiency objectives and the time lag between the investment and the consideration of costs in the revenue cap. The classification of costs as influenceable or non-influenceable plays only a subordinate role. The results highlight the need to consider innovation in the regulation design of electricity distribution system operators. Further research should tackle the specific instruments needed to account for innovation. The brief discussion provides some initial ideas and concepts of ways to consider innovation in regulation. However, in order to obtain better founded conclusions, this topic definitely needs more research.

Thirdly, the above conclusions show that regulators should continuously rethink their regulation design. The development within a market or sector may cause new challenges for the regulator. It has been expedient not to consider innovation in the regulation design for electricity grid operators in the past, because innovation played only a minor role. Today, however, it is necessary to take innovation into consideration, due to the need for innovations to integrate the decentralized RES-E generation.

6.7 Appendices of Chapter 6

A.6.I: Notations used in the economic calculation:

a_{per}	length of the regulation period
c	total costs of the grid operator (CAPEX)
c_c	costs considered in the revenue cap
c_c*	total costs of the grid operator (CAPEX) in the next regulation period
c_i	influenceable costs
c_n	costs not considered in the revenue cap
c_{pni}	permanent non-influenceable costs
c_{tni}	temporarily non-influenceable costs
E_t	earnings in period t
E_t*	earnings in period t with effectiveness of efficiency value
I_0	payment (investment) in t=0
IRR	internal rate of return (here: IRR=r)
L_n	earnings for liquidation in period n
n_{per}	specific year within the regulation period with t=1,…, aper
P_t	payment in period t
r	'real' internal rate of return (here: r=IRR)
r_{all}	allowed rate of return
s_i	share of influenceable costs
s_{pni}	share of permanent non-influenceable costs
s_{tni}	share of temporarily non-influenceable
t_c	number of years for costs being considered in the revenue cap
$t_{c,n}$	number of years for costs being considered in the revenue cap for costs cn
T_L	(calculatory) lifetime
t_n	number of years for costs not being considered in the revenue cap
t_{1per}	starting point of the next regulation period
t_{2per}	end point of the next regulation period
x_{ind}	individual efficiency objective
θ	efficiency value

A.6.II: Derivation for the economical approach in Section 6.3 (equation (6-9)):

$$E_t = \frac{c_c{}^*}{t_L} \cdot (1 + r_{all})^t C$$

$$= \frac{(c - \frac{c_i}{a_{per}} \cdot n_{per})}{t_L} \cdot (1 + r_{all})^t C$$

$$= \frac{c - \frac{c - c_{pni} - c_{tni}}{a_{per}} \cdot n_{per}}{t_L} \cdot (1 + r_{all})^t c$$

$$= \frac{c - \frac{c - c \cdot s_{pni} - (c - c \cdot s_{pni}) \cdot \theta}{a_{per}} \cdot n_{per}}{t_L} \cdot (1 + r_{all})^t c$$

$$= \frac{c(1 - \frac{1 - s_{pni} - (1 - s_{pni}) \cdot \theta}{a_{per}} \cdot n_{per})}{t_L} \cdot (1 + r_{all})^t c$$

$$= \frac{c(1 - \frac{(1 - s_{pni}) \cdot (1 - \theta)}{a_{per}} \cdot n_{per})}{t_L} \cdot (1 + r_{all})^t c$$

A.6.III: Influence of investment alternatives on efficiency values:

Scenario / DSO	SFA				DEA			
	I Conventional	**II Refused**	**III* Smart***	**III** Smart****	**I Conventional**	**II Refused**	**III* Smart***	**III** Smart****
1	100.00%	100.00%	100.00%	96.32%	95.73%	100.00%	95.73%	89.82%
2	100.00%	100.00%	99.79%	87.85%	100.00%	100.00%	100.00%	100.00%
3	58.93%	66.77%	58.36%	51.83%	90.26%	93.89%	82.06%	72.88%
4	86.96%	96.88%	86.12%	77.51%	83.24%	93.64%	83.24%	74.92%
5	97.61%	100.00%	96.67%	88.61%	90.04%	99.04%	90.04%	82.53%
6	30.22%	30.68%	29.93%	29.22%	30.77%	31.54%	30.77%	30.04%
7	49.89%	51.33%	49.41%	47.62%	55.33%	57.48%	55.33%	53.32%
8	41.32%	42.66%	40.92%	39.32%	59.71%	61.83%	59.30%	56.98%
9	41.35%	43.39%	40.95%	38.77%	41.76%	40.37%	38.10%	36.07%
10	32.17%	33.42%	31.86%	30.44%	36.84%	35.46%	33.81%	32.30%
11	70.79%	78.83%	70.11%	63.13%	80.90%	82.87%	73.70%	66.36%
12	39.33%	40.70%	38.95%	37.34%	36.87%	38.52%	36.87%	35.35%
13	94.42%	100.00%	93.51%	86.95%	98.37%	100.00%	98.37%	91.47%
14	93.78%	100.00%	92.88%	84.77%	81.78%	90.43%	81.78%	74.64%
15	37.33%	38.59%	36.97%	35.48%	54.85%	54.40%	52.12%	50.02%
16	42.93%	44.42%	42.52%	40.78%	40.30%	42.10%	40.30%	38.65%
17	54.59%	56.59%	54.06%	51.75%	53.47%	55.97%	53.47%	51.18%

18	79.36%	85.42%	78.60%	72.78%	81.51%	88.59%	81.51%	75.48%
19	42.79%	44.64%	42.38%	40.34%	40.63%	42.79%	40.63%	38.68%
20	86.08%	96.90%	85.25%	76.11%	86.39%	89.30%	78.57%	70.14%
21	49.41%	50.64%	48.93%	47.33%	55.23%	57.16%	55.23%	53.43%
22	88.77%	91.81%	87.91%	84.33%	88.40%	92.32%	88.40%	84.80%
23	95.20%	100.00%	94.29%	87.37%	94.10%	100.00%	94.10%	87.20%
24	66.90%	70.98%	66.26%	62.13%	53.62%	56.90%	53.12%	49.81%
25	94.40%	100.00%	93.49%	85.54%	92.64%	100.00%	92.64%	84.76%
26	42.57%	43.47%	42.16%	40.93%	100.00%	100.00%	100.00%	100.00%
27	62.14%	63.19%	61.54%	59.97%	59.80%	61.41%	59.80%	58.28%
28	44.23%	44.80%	43.81%	42.86%	46.09%	46.09%	46.09%	45.09%
29	54.96%	57.29%	54.43%	51.84%	54.40%	57.26%	54.40%	51.82%
30	73.88%	78.86%	73.17%	68.19%	61.57%	61.30%	56.82%	57.38%
31	39.56%	41.12%	39.18%	37.42%	37.86%	36.51%	34.79%	33.23%
32	76.80%	81.85%	76.06%	71.03%	100.00%	100.00%	100.00%	100.00%
33	73.90%	77.58%	73.18%	69.26%	76.73%	76.73%	76.73%	72.62%
34	81.28%	85.58%	80.50%	75.99%	83.19%	88.44%	83.19%	78.52%
35	100.00%	100.00%	100.00%	99.78%	83.38%	90.04%	83.38%	77.64%
36	79.64%	81.75%	78.88%	76.20%	60.97%	63.19%	60.97%	58.90%
37	55.43%	57.60%	54.90%	52.43%	50.68%	53.18%	50.68%	48.41%
38	81.90%	87.20%	81.12%	75.82%	92.84%	99.81%	92.84%	86.78%
39	39.14%	40.67%	38.76%	37.02%	36.27%	38.06%	36.27%	34.65%
40	35.69%	36.23%	35.35%	34.59%	40.22%	41.22%	40.22%	39.27%
41	70.03%	74.15%	69.35%	65.14%	70.31%	70.31%	70.31%	66.04%
42	74.85%	80.26%	74.13%	68.86%	70.66%	76.52%	70.66%	65.64%
43	32.49%	33.78%	32.18%	30.68%	35.20%	35.20%	32.01%	30.52%
44	38.24%	39.13%	37.87%	36.70%	47.63%	47.63%	47.63%	46.15%
45	20.16%	20.45%	19.97%	19.66%	23.21%	23.70%	23.21%	22.74%
46	97.97%	100.00%	97.03%	94.06%	86.83%	86.83%	86.83%	84.18%
47	100.00%	100.00%	100.00%	98.20%	99.09%	100.00%	99.09%	93.72%
48	47.06%	48.91%	46.61%	44.52%	44.33%	46.51%	44.33%	42.33%
49	39.26%	41.88%	38.88%	36.29%	51.34%	50.28%	46.69%	43.58%
50	43.61%	44.29%	43.19%	42.15%	46.18%	47.36%	46.18%	45.07%
Average	63.59%	66.49%	63.05%	59.46%	65.63%	68.04%	64.65%	61.27%

*Smart investment has the same costs as the conventional investment;
**Smart investment has twice times the costs as conventional.

7 Conclusions and future work

The electricity transition towards a power generation based on renewable energy resources (RES-E) poses major challenges on the distribution system operators (DSOs). These DSOs will play a central role in this transformation process since the vast majorities of RES-E technologies (photovoltaic (PV), wind and biomass) are connected to distribution grids. Also new powerful consumption devices emerge which can be controlled by external steering signals (such as prices) to shift the demand of electricity in time (Demand Side Management (DSM)). Examples for these kinds of appliances are electric heat pumps, electric vehicles or new types of controllable white good devices. Furthermore, storage technologies installed in distributed grids (decentralized storage assets) are expected to play an important role in future systems. Both, DSM and storage assets, are expected to provide substantial contributions for the transformation process, since the flexibility of the power consumption (and for storage also of the withdrawal of electricity) can be exploited to compensate for the fluctuations in the feed-in of PV and wind generation.

Hereby, the challenges to cope with these new appliances and technologies for an efficient integration and operation of the consumption, generation and storage devices in distribution grids are multidimensional. Furthermore, multiple stakeholders with different optimizations objectives are involved. Both technical and economic aspects need to be considered, since e.g. not all (economic) trading transactions may be possible due to (technical) restrictions on grid levels and not all (technically required) investments on grid levels for a full exploitation of RES-E and DSM potential in distribution grids may be the best choice from an (economic) welfare point of view. Moreover, the regulation method may significantly influence the investment decisions of grid operators and the strategy whether to innovate or not. As shown in this work, these technical, economic and organizational issues are essential and should be considered for implementing smart grids and realizing the energy transition by increasing the fraction of RES-E on the total power generation.

7.1 Contributions

As mentioned in Chapter 1 several contributions from different scientific disciplines are provided in this thesis. Therefore, first the background of the electricity supply chain, natural monopolies and markets as well as technical restrictions in distribution grids and the described vision of a ‘Smart Grid’ are presented (Chapter 2) and the importance of investigations in these research fields is illustrated.

Feed-in characteristics

Next, as a basis for the analysis and enabling further research on the integration of RES-E, an extended insight in the RES-E feed-in characteristics is provided in Chapter 3. The feed-in profiles of photovoltaic, wind and biomass generators connected to one distribution grid area (in the case considered approximately 100 km²) are investigated. The values are given with 15 minutes interval for the years 2010 and 2011 and for 10 generators of each considered technology. It is shown that the profiles of the feed-in of the different technologies neither indicate supplement nor complement behavior - in other words, grid planning should not rely on the actual feed-in of PV and wind (also when considering different PV/wind portfolios) since numerous time periods without any feed-in from PV and wind are given. Furthermore, also a worst-case calculation of feed-in values based on the nominal power of the generators is too pessimistic due to the diversity factors occurring with an increased number of generators and a mix of different RES-E technologies.

For the biomass generators, no correlation of the feed-in profiles to each other is given, but a high reliability for the electricity generation (up to 97.6% of the theoretical possible value). This implies that this technology can be seen as a constant contribution to electricity generation under current feed-in schemes.[38] Between different PV generators and between different wind generators, as expected, high correlation coefficients exist, so that grid planning aiming on an appropriate dimensioning of grid assets is aggravated due to seldom, but high feed-in peaks. Considering the relation between the feed-in values of PV, wind and biomass generation among themselves (e.g. PV to wind feed-in), no statistical relevance for the correlation coefficiencies is detectable.

Based on the derived results, a tool is introduced to determine characteristic feed-in values based on the RES-E portfolios at hand. The analyzed profiles and presented results enable

- the appropriate dimensioning of storage assets for peak shaving (e.g. to avoid conventional reinforcements with bigger and/or additional grid assets such as cables and transformers),
- the evaluation of Demand Side Management (since the generation profiles are determined the DSM-appliance may have to react on) and
- the assessment of congestion management to reduce the feed-in peaks by throttling RES-E in certain time periods in distribution grids.

Storage dimensioning

Because storage assets are likely to play important roles for a further integration of RES-E, the elaborations in Chapter 4 focus on the introduction of storage assets in distribution grids. Based on typical parameters of battery systems, a model for storage assets is derived. Using this model, cost-driving parameters such as the capacity of the storage assets as well as the Depth of Discharge, the (in-)efficiency and the degradation factor can be considered appropriately. The real world feed-in data of the RES-E profiles from Chapter 3 are used in the model to determine the values of storage parameters for an appropriate introduction of these assets in distribution grids. It is shown that both, the RES-E technology considered and the diversity factor, have significant impact on the energy to power (*E2P*)-ratio of the storage. This ratio determines the required capacity depending on the power of the storage asset and is seen as important and meaningful indicator because capacity is cost-driving and the *E2P*-ratio is very technology-specific. As it is shown in the analysis, storage for the peak-shaving of wind power leads to a higher *E2P*-ratio by a factor of 20. The diversity factor has a substantial influence as well. If the feed-in of ten instead of one generator needs

[38] Note that the feed-in data are derived from generators located in a German distribution grid and hence, also the current German supporting scheme for RES-E needs to be considered. As it is the case in a lot of other countries, RES-E is incentivized in Germany to feed-in as much as possible, regardless of grid constraints or market needs.

to be peak shaved, the *E2P*-ratio is reduced by 9% to 42% (PV) and 17% to 91% (wind), depending on the power to be reduced. However, such a more central storage is only possible when there are no further grid constraints between the placement of the storage asset and the location of the generators. The investigations presented in this chapter are useful to narrow down the possible choices of storage technologies depending on the feed-in profiles in the specific grids.

Storage profitability

In the second part of Chapter 4, a methodology is presented to derive break-even points for storage assets if they are used as a substitute to conventional grid reinforcements. The presented methodology considers the time value of money as well as capital and operational expenditures for both alternatives (storage asset and conventional reinforcement). Furthermore, the positive impact of decentralized storage assets for upstream grid levels due to reduced feed-in peaks is taken into account. For a case study on a real world low voltage grid area faced with reinforcement needs due to the installation of PV generators, these break-even points are shown to range between 100 and 500 € per kWh of installed capacity. These values depend on the main influencing parameters being the costs per meters of cable (conventional reinforcement) and the lifetime of the storage asset. Further influencing parameters on the break-even point are evaluated using a sensitivity analysis indicating also a significant influence of the Depth of Discharge of the storage asset on the break-even point. The profitability can be increased significantly if not all of the seldom, but high feed-in peaks need to be stored since then, the required capacity can be chosen smaller. Furthermore, the cooperation of stakeholders seems to be promising for an increased market penetration since in the presented use case, in more than 50% of the year, the storage asset is completely unused for peak-shaving purposes and could be used to gain benefits for other objectives (such as arbitrage at spotmarkets or to provide primary balancing power).

This cooperation of stakeholders is further investigated in Chapter 5. In liberalized markets as given in a lot of countries, the market roles are either faced with competition (for example for generation, supply, trading and services) or operating in natural monopolies (transmission and distribution grids). These market roles are unbundled and strive towards their own objectives and thus, different interests are given for using the increased flexibility of consumption devices (DSM-appliances such as heat pumps) and the potentials of new emerging technologies (such as decentralized storage assets). Hence, the interaction of the stakeholders becomes an important topic for an efficient integration of RES-E.

Interaction of stakeholders

The operation of decentralized storage assets and heat pumps is modeled in Chapter 5 considering different steering approaches of a distribution system operator (objective: peak shaving) and a trading company (objective: arbitrage to exploit price spreads at the spotmarket).

For the storage case it is shown for a 30/10-kV grid area that the resulting profiles of the storage usage do not deviate significantly. However, seldom situations occur when price signals at the day ahead and intraday market incentivize the trader to withdraw the electricity from the storage and feed it into the grid although a local surplus is given. The simulations even show that grid reinforcement may be induced only because of the additional feed-ins of the storage assets. These situations occur because price signals at the spotmarket are not only influenced by RES-E in distribution grids and local consumption and generation profiles. As it is shown in this chapter, the prices are overcompensated by other influencing factors such as a lack of decentralized feed-in of RES-E in other areas or a lack of conventional power generation and high consumption in the (global) market area. Although the RES-E share increased from 2011 to 2012, the measured correlations of the local feed-in values for the considered area to the global price signals of the spotmarket did not increase accordingly. Hence, a steering of decentralized assets only based on price signals without considering (local) grid constraints will be harmful for the society due to unreasonable high costs for the required reinforcements in distribution grids. This effect is further documented with a simulation where a cooperation of the stakeholders is integrated. For this, the objective is defined as maximizing the profit by arbitrage while taking the grid constraints into account. The peaks for the considered use case are reduced from 10.29 MW to 6.43 MW (-37.5%) for the day-ahead simulations with a decrease of the profits by only 1.86%. For the intraday prices, the decrease of the peak amounts to 26.7% whereas the profit decreases only by 1.28%. Considering the absolute values for the reinforcements required to cope with the peaks and the lost profits on the trading side, a combined operation seems to be highly recommended from a welfare point of view. Further suggestions to efficiently integrate storage assets in distribution grids are also presented in this chapter, such as a) enabling the DSO to operate storage assets for own purposes and b) incentivize stakeholders for an investment in storage assets by reduced grid fees only if the local grid constraints are taken into account.

The recommendation for a cooperation of stakeholders is also valid in the heat pump use case. As presented in this second main part of Chapter 5, the amounts of required investments in a low voltage grid depend on the stakeholder which steers the heat pumps. Hereby, the objective of peak shaving used by the distribution system operator leads to lower investments costs (-10% compared to the status quo) and a steering only based on prices will increase the investment costs in the considered region by up to 71%. In the latter case, the end-user may benefit if real-time pricing is applied and the operation of the heat pump can be shifted to low-price periods. However, a payback period from an overall economic and welfare point of view is not even reached if uncontrolled steering of heat pumps based on (uniform) prices is enabled for the considered grid area. In other words, the costs for the reinforcement required to cope with the consumption peaks of heat pumps outweigh the benefits with lower costs for the operation of the electric pumps by up to a factor of 3.6. This effect is caused by the steering of heat pumps based on one steering signal, so that, e.g. in low-price periods all heat pumps operate with the maximal power and, as a consequence, the grid assets need to be reinforced. Especially in existing residential areas these investments are very high due to the high quality surfaces and as presented in the case study, may overcompensate the benefits for the households by reacting on low-price periods.

Hence, in both cases a cooperation of the stakeholders is beneficial, at the latest when the steering of these flexible devices is possible for different stakeholders, e.g. due to an increase usage of information and communication technologies. Since this process already started in a lot of countries and the cooperation may even improve the profitability of decentralized storage assets, the need for adaptions in the design of the supply chain and the interaction of the stakeholders is highlighted. Furthermore, the results show that assuming a ‘copperplate’ scenario without considering grid constraints will be unreasonable expensive in the end for the whole society.

Regulation of innovations in grids

The perspective of economic decisions and investment behavior in distribution grids and the incentivizing for innovations is taken up in Chapter 6. Since distribution grids are faced with the characteristics of a natural monopoly and thus, DSOs are regulated by an authority (in most case a national regulation agency) the economic framework for DSOs differs significantly compared to ‘usual’ competitive markets. Hereby, the regulation method has significant influence on the investment decisions of the DSOs. Taking into account the central role of DSOs in the energy transition, the research focuses on identifying and evaluating incentives for DSOs to participate in this transition process. More precisely, in Chapter 6 it is investigated which incentives are provided by the regulation method on whether or not and how to integrate RES-E. The elaborations are oriented on the German revenue cap regulation and include efficiency analyses of 50 different grid operators. A methodology is derived to determine internal rate of returns for investments considering the special functionalities of cap regulations. It is shown that the allowed rate of return will never be achieved due to the influence of time lags for the costs occuring with investments and their consideration in the revenue cap. Furthermore, the highest efficiency (and, thus, the highest profitability also for the existing asset base) is reached if the DSO refuses access of RES-E and the lowest incentives are provided to invest in innovations. However, this cannot be the political objective for a further increase of the RES-E share.

The methodology derived in Chapter 6 enable a determination of the influencing parameters on investment decisions in grids and illustrate that - next to the technological issues and opportunities occurring with a further transition to sustainable electricity generation - the perspective of economic regulation is crucial to provide incentives for the investments in innovations in distribution grids.

7.2 Recommendations for future work

In the research presented in this thesis, several scientific disciplines involved in the ‘electricity transition’ with a focus on distribution system operators are considered. Hereby, a basis is given for an appropriate addressing of the current and future issues occuring with the integration of RES-E which should be deepened in future work.

A first important topic in this context is the efficient integration of RES-E in grids and markets for the further increase of RES-E shares. Since in several countries the RES-E technologies have experienced significant growth rates, the market design needs to include appropriately the operation of RES-E. First of all, this integration can be seen from a market point of view. Eurelectric (2011) state that the electricity sector is seen as one of the most complex and fragmented sectors of all. Further research should focus on decreasing this complexity, e.g. by incentivizing RES-E to be a more active part of the market, so that selling and meeting of schedules, nomination and balancing requirements is task of the RES-E operator and not (as it is today) task of the transmission system operator and of the suppliers. For this, the research should also deal with appropriate support mechanisms. Since wholesale markets and transmission grids are embedded in a European context, national ‘solo runs’ seem to contradict the initial objectives of the European Commission to liberalize the energy markets and enable a European-wide wholesale and retail market. Further research may highlight the need for a redesign of the current regimes with respect to the markets and supply chains itself (e.g. the merit-order approach described in Section 2.1) since PV and wind generation are operating with marginal costs close to zero, but fluctuate, so that additional generation is required as back-up capacity or massive investments in storage capacities are needed. These organizational issues and the goal to efficiently integrate RES-E need to consider local grid constraints to avoid external effects from a cost perspective (externalities). Hereby, externalities are defined as costs resulting from an activity of a party A but having impact on an uninvolved party B which is not compensated by A (cf. Buchanan (1962)). The costs for the connection of RES-E in areas with no further need for generation but inducing high reinforcement needs to transport the surplus energy to other consumption areas can be seen as externality, since currently, the end-users consuming the electricity in that area have to bear the costs for the reinforcements. Hereby, the electricity is produced in a (mainly rural) area and the costs for the needed infrastructure are paid by the inhabitants of the area although the electricity is consumed by end-users in other (mainly urban) areas. In the current market design, these end-users as well as the RES-E investor are not involved in paying the costs for the reinforcement although they have the benefits from the investments. This effect has already led to first political discussions in Eastern parts of Germany (see e.g. the request for a nationwide compensation in Walsmann (2010)).

The above example shows how in Germany costs are allocated, but in other countries national regulations and legal frameworks may differ significantly (cf., for example for Europe in Zane, et. al. (2012)). Hence, harmonization seems to be advisable also for this topic. Hereby, it has to be considered that there exist a trade-off between reducing the complexity of the market design and considering appropriately the local grid constraints and externalities. Future designs for supply chains, markets and regulation methods need to be as transparent as possible and only as complex as implicitly required. Hence, a lot of research is needed to determine appropriate suggestions for these organizational issues. In any case, a more integrated view on the interactions of decentralized generation, decentralized storage, transmission and distribution as well as of supply, trading and consuming of electricity is required.

Secondly and as mentioned in Chapter 1 and 2, there will be a need for short, mid and long-term storage of RES-E to be able to react on fluctuations in the generation profiles with storing and withdrawal of electricity in seconds up to months. A basis for dimensioning these storage assets depending on the prevailing situations in the distribution grids is given in this work. To get further insights in the potentials of the storage assets and further challenges occuring with a wider integration of these assets in grids and markets, pilot projects are useful. The gained information on the behavior of these assets in real world situations should be distributed as far as possible to enable future stakeholders to learn from these results. In this work, the research scope was on peak-shaving in the time scale of hours. However, for an electricity generation without large generation units (such as fossil and nuclear power plants), new challenges will occur. These challenges include the problem of missing rotating masses (and hence, other consumption/generation/storage appliances will need to react in a very short time) as well as the leveling out of seasonal fluctuations in the power supply and demand. For the seasonal and, thus, long-term perspective, new assets have to be introduced which are able to level out fluctuations in the RES-E generation profiles without having cost-driving capacity restrictions. Such solutions may be by appropriately combining the sectors of electricity, natural gas and/or heat. For example, the power to gas approach to produce hydrogen or methane using surplus electricity and reuse the gas to be combusted and to generate electricity in the case of a lack of feed-in may be promising. However, the efficiency of this technology is still low and the conventional reinforcement is clearly preferable from a grid operators' perspective. In contrast and as shown in this work, the profitable investment in such innovative assets may be given sooner if multiple stakeholders and objectives are considered and costs and benefits are allocated appropriately. As storage is only one of the solutions to cope with the fluctuations of RES-E also other approaches need to be considered and benchmarked to find the best mixture of different solutions for the integration of RES-E. In future energy markets and grids, all of the solutions such as the extension of transmission grids to enable more cross-border trade of power, increased Demand Side Management to enable end-users to adjust consumption profiles based on the availability of electricity, increased interaction of the energy systems to use the advantages of the electricity, natural gas and heat sectors and centralized as well as decentralized storage of electricity will contribute to the design of the energy system. Furthermore, new solutions for voltage issues in distribution grids will emerge, such as the voltage regulation appliances briefly presented in Section 2.2. Further and intensified research on these new technologies is needed, but most likely all of them will be required to some extend in future grids and markets.

As a third aspect, additional scientific disciplines will play an important role. With an increase of communication between devices and market roles, also an increased importance for cyber security is given. As briefly presented in Subsection 5.3.2, such an interaction to steer devices and grids may consider prediction, planning and real-time control of energy streams (see details on the TRIANA approach in Molderink (2011), Bakker (2012) and Bosman (2012)). However, these approaches require communication, e.g. of expected and realized load profiles and hence, appropriate security mechanisms need to be implemented. Further aspects are to be found in psychological dimensions, which are relevant with an exploitation of the potential of Demand Side Management. Due to reservations with respect to this subject and the fear of misuse and too high transparence in consumption behavior, end-users may not participate in the steering or being steered by adjustable consumption, generation and storage appliances. Providing appropriate incentives whereby end-user needs are taken seriously will be a further task, which is relevant for a further implementation of Demand-Side Management.

Finally, the future work directly mentioned in the particular chapters should be considered. These level playing fields include the refinement of the storage model based on real world behavior to reproduce appropriately the technical and economic aspects of storage assets installed in real world situations. Further situations in grids with the need for conventional reinforcements should be identified to evaluate the meaningfulness of other alternatives and innovations for the integration of RES-E. Also the congestion management to throttle the feed-in of RES-E (which is currently in most countries not allowed in distribution grids) should be further investigated, e.g. to illustrate the trade-off between implementing the 'copperplate' scenario to enable the transport of all feed-in peaks of RES-E and throttling RES-E in certain time periods, if preferable from a welfare point of view. These deliberations need to take storage alternatives, DSM potentials and other grid innovations into account, showing again the complexity of finding the best option for an efficient integration of RES-E. In Chapter 6, some suggestions for adjusting the regulation of grids to incentivize innovations are given, which may be deepened and evaluated, e.g. based on further and future best-practice examples from other countries.

All these research fields are important for a successful energy transition. The results presented in this thesis are based on real world data of the first periods of this transition process (e.g. for Germany for 2012 with a RES-E fraction of 22.9% on the total electricity generation (BMU (2013)). Hence, the need to test concepts and find solutions is illustrated even more when considering an increase up to 50% of electricity from renewable sources within the next 15 till 20 years, mainly based on fluctuating RES-E technologies such as PV and wind.

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About the author

Stefan Nykamp was born in Nordhorn, Germany on August 6, 1983.

In 2004 he started a cooperative study at the University of Cooperative Education, Lingen and RWE Westfalen-Weser-Ems AG, Osnabrück, Germany. In 2007, he obtained his bachelor degree in Economic Engineering (B. Eng.). From 2008 to 2010 he studied Energy Economics extra-occupational at the University of Münster and RWTH Aachen, Germany and completed the studies with a joint master's degree of both universities (M. Sc.) and a certificate of excellence. Since 2010, he is doing his Ph.D. studies extra-occupational at the University of Twente, The Netherlands. His Ph.D. research culminates with this dissertation.

He started his professional career in 2007 with RWE Westfalen-Weser-Ems AG in Nordhorn as a project engineer, with technical and economical responsibilities for projects in the power and natural gas distribution grid. In 2010 he became team leader in the planning department of RWE Deutschland AG, Nordhorn and - after a restructuring - he currently works with Westnetz GmbH in Bad Bentheim. Furthermore, he is involved as project leader and team member in several projects in the headquarters, e.g. in research and development activities and benchmark projects.

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